L1	1		Responses to Interrogatories from Board Staff

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	3		Responses to Interrogatories from CCC
	4		Responses to Interrogatories from CME
	6		Responses to Interrogatories from Energy Probe
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M	TAB		INTERVENOR EVIDENCE
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	6		Energy Probe Evidence – Prepared by Lawerence P. Schwartz
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N			IMPACT STATEMENT
	1	1	Impact Statement
	1	2	Summary of Production and Revenue Requirement Impacts
J			UNDERTAKINGS
	1.1		To file the Ontario Government backgrounder announcing prices on electricity from Ontario Power Generation
	1.2		To provide a calculation showing the impact on the test period deficiency of an assumption that the credit spread on the long-term debt components of the capital structure was 80 basis points for 2008 and 2009.
	1.3		To provide an analysis of what is described on Page 19 of the CIBC report as option 2 in connection with the test period; show the difference and provide an explanation between the proposed method and the method recommended by CIBC and option 2 method in L-2-58.
	1.4		Determine if any additional information is available to support the statements made in paragraph referred to in the OPG Annual Report.
	1.5		Provide table similar to Note 10 showing in two parts, one for liability in respect of the prescribed assets and the other in respect of the Bruce Station.
	2.1		
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EXHIBIT LIST			
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JT			UNDERTAKINGS AT TECHNICAL CONFERENCE
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KT			MISCELLANEOUS EXHIBITS FILED AT TECHNICAL CONFERENCE
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	1.2		OPG’s Response to Board Staff Follow-up Questions on OPG Responses to Interrogatory Number 2
	1.3		OPG’s Response to Board Staff Follow-up Questions on OPG Responses to Interrogatory Number 3
	1.4		OPG’s Response to Board Staff Follow-up Questions on OPG Responses to Interrogatory Number 4
	1.5		OPG’s Response to Board Staff Follow-up Questions on OPG Responses to Interrogatory Number 5
	1.6		OPG’s Response to Board Staff Follow-up Questions on OPG Responses to Interrogatory Number 6
	1.7		OPG Response to matters Under Advisement at the Technical Conference (Transcript Reference: page 108 line 28 – page 109 line 1)
	1.8		OPG Response to matters Under Advisement at the Technical Conference (Transcript Reference: page 99 line 7)
	1.9		OPG Response to matters Under Advisement at the Technical Conference (Transcript Reference page 28 line 17)
	1.10		OPG Response to matters Under Advisement at the Technical Conference (Transcript Reference – pg 35 line 26)
	1.11		OPG Response to matters Under Advisement at the Technical Conference (Transcript Reference pg 112 line 4)

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing April 1, 2008.

APPLICATION

1. The applicant, Ontario Power Generation Inc. ("OPG") is a corporation, incorporated under the *Ontario Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.

2. In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, for an order or orders approving the payment amounts for generating facilities prescribed under Ontario Regulation 53/05 ("O. Reg. 53/05"), as amended, of the Act for the period from April 1, 2008 through December 31, 2009 ("test period"), or for such other period determined to be appropriate by the OEB. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB use a forecast cost of service methodology to approve payment amounts for the test period as established in EB-2006-0064, "A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc." and "Filing Guidelines for Ontario Power Generation."

3. OPG also seeks an order of the OEB declaring the current payment amounts interim effective April 1, 2008. OPG seeks an order establishing payment amounts that allow full recovery of the test period revenue requirement over the test period.

4. OPG also seeks an interim order for increased payment amounts effective April 1, 2008 in the amount of $35.35/MWh for the output of Sir Adam Beck I, Sir Adam Beck II, Sir

Adam Beck Pump Generating Station, DeCew Falls I, DeCew Falls II, and R.H. Saunders Generating Stations (together the "regulated hydroelectric facilities") and $53.00/MWh for the output of Pickering A Generating Station, Pickering B Generating Station, and Darlington Generating Station (together the "nuclear facilities"), all subject to adjustment once final payment amounts are determined. These interim payment amounts are calculated based on 50 percent recovery of the test period revenue deficiency on a unit of energy basis. During the period of interim rates, OPG expects to retain the hydroelectric incentive mechanism under O. Reg. 53/05 under which the output from the regulated hydroelectric facilities in excess of 1900 MWh in any hour receives market price.

5. OPG is seeking approval for disposition of the balances in the deferral and variance accounts, using a payment rider for the nuclear accounts and as part of the payment amount for the regulated hydroelectric facilities. OPG is also seeking an order continuing and/or establishing deferral and variance accounts during the test period.

6. To achieve the revenue requirement and disposition of the balances in the deferral and variance accounts, OPG is seeking payment amounts and riders as follows:
   - For the regulated hydroelectric facilities, $37.90/MWh for the average hourly net energy production (MWh) from the regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO") – administered energy market. Where production from the regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO - administered market.
   - For disposition of the regulated hydroelectric variance account, recovery of $0.7M by including this amount in the revenue requirement used to calculate the hydroelectric payment amount.
   - For the nuclear facilities, a payment amount of $58.2M/month plus $41.50/MWh for the output generated from the nuclear facilities.

- For disposition of the nuclear variance and deferral accounts, recovery of $342M at a rate of $1.45/MWh for the output from the nuclear facilities.

7. The Application will be supported by written and oral evidence. The written evidence filed by OPG may be supplemented or amended from time to time by OPG prior to the OEB's final decision on the Application.

8. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

9. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

10. OPG requests that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule 24 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

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Dated at Toronto, Ontario, this 30th day of November 2007.

Ontario Power Generation Inc.

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Michael A. Penny
Torys LLP

APPROVALS

In this Application, OPG is seeking the following specific approvals:

- An order from the OEB declaring OPG's payment amounts interim as of April 1, 2008.

- An order from the OEB establishing interim payment amounts of $35.35/MWh for the output of Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station, DeCew Falls I, DeCew Falls II, and R.H. Saunders Generating Stations (the "regulated hydroelectric facilities") and $53.00/MWh for the output of Pickering A Generating Station, Pickering B Generating Station, and Darlington Generating Station (the "nuclear facilities") effective April 1, 2008. During the period of interim rates, OPG expects to retain the hydroelectric incentive mechanism under O. Reg. 53/05 under which the output from the regulated hydroelectric facilities in excess of 1900 MWh in any hour receives market price.

- The approval of a revenue requirement of $1283M for the regulated hydroelectric facilities and a revenue requirement of $5152M for the nuclear facilities for the period of April 1, 2008 through December 31, 2009 (the "test period") as set out in Ex. K1-T1-S1.

- The approval of a rate base forecast of $3886M and $3870M for the regulated hydroelectric facilities for the years 2008 and 2009, respectively and $3515M and $3484M for the nuclear facilities for the years 2008 and 2009, respectively, as summarized in Ex. B1-T1-S1. OPG's request for this approval is supported by an examination of the asset and liabilities values and other related matters in the 2006 audited financial statements pursuant to paragraph 6 (2) 5 of the Regulation and asset forecast as found in Exhibit B.

- Approval of a capital budget for the regulated hydroelectric facilities for the test period, as presented in Ex. D1-T1-S1 and for the nuclear facilities for the test period, as presented in Ex. D2-T1-S1.

- Approval of a production forecast of 31.5 TWh for the test period for the regulated hydroelectric facilities and 88.2 TWh for the test period for the nuclear facilities. Production forecast is presented in Ex. E.

- Approval of a deemed capital structure of 42.5 percent debt and 57.5 percent equity and a combined rate of return on rate base of 8.48 percent and 8.56 percent for 2008 and 2009, respectively, including a rate of return on equity (“ROE”) forecast of 10.5 percent, as presented in Ex. C1-T1-S1 and Ex. C1-T2-S1.

- Approval of the automatic adjustment mechanism to adjust the rate of return on common equity in future periods, as discussed in Exhibit C1-T1-S1.

- Approval of a payment amount for the regulated hydroelectric facilities of $37.90/MWh for the average hourly net energy production (MWh) from the regulated facilities in any given month (the “hourly volume”) for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator (“IESO”) – administered energy market. Where production from the regulated hydroelectric facilities is less than the hourly volume, OPG’s revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO - administered market. The payment amount for the regulated hydroelectric facilities is set out in Ex. K1-T2-S1 and the design of the regulated hydroelectric payment amount is set out in Ex. I1-T1-S1.

- Approval of a payment amount for the nuclear facilities, of $58.2M/month plus $41.50/MWh, as set out in Ex. K1-T3-S1.

- For the nuclear facilities, approval for recovery of $342M from the variance and deferral accounts using a payment rider of $1.45/MWh, as presented in Ex. J1-T1-S1 and Ex. J1-T2-S1. For the regulated hydroelectric variance account, recovery of $0.7M by adding this amount to the revenue requirement used to calculate the hydroelectric payment amount, as presented in Ex. J1-T2-S1 and Ex. K1-T1-S1.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:

  - A variance account to record the deviation from forecast revenues associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions.
  - A variance account to record the deviation from forecast revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
  - A variance account to record the deviation from forecast non-capital costs associated with work to increase capacity or to refurbish a generation facility. The account would include deviations in costs associated with the potential refurbishment of Pickering B and Darlington Generating Stations.
  - A variance account to recover the deviation from forecast non-capital costs for planning and preparation for the development of proposed new nuclear generation facilities.
  - A variance account to record the deviation between actual and forecast nuclear fuel costs.
  - A variance account to record the customer's share of revenues from energy sales to Hydro Quebec as a result of segregated mode of operation at R.H. Saunders, and from water transactions at the regulated hydroelectric facilities.
  - A variance account to record the deviation between actual and forecast pension and other post-employment benefit expenses related to changes in the discount rate.
  - A deferral account to record non-capital costs associated with the planned return to service of units at the Pickering A Generating Station.
  - A deferral account to record the revenue requirement impact of the change in the nuclear decommissioning liability arising from the December 2006 approved reference plan as defined in the Ontario Nuclear Funds Agreement.
  - A variance account to capture the tax impact of changes in tax rates, rules

and assessments.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. J1-T3-S1.

SUMMARY OF APPLICATION

This is OPG's first application for an order of the Ontario Energy Board approving payment amounts for certain generating facilities prescribed by regulation under the *Ontario Energy Board Act, 1998*. This summary provides background on the regulatory framework governing the prescribed facilities, an overview of the key drivers of cost in OPG's business and addresses certain timing considerations associated with the Application.

By way of background, OPG is different from other electricity generators in Ontario in at least three significant respects. First, OPG is the largest generator of electricity in Ontario and its prescribed facilities represent a large proportion of Ontario's total electricity generation. In 2006, the output from the prescribed facilities met approximately 45 percent of total annual demand in the IESO - administered electricity market. Further detail with respect to the prescribed facilities is provided in Ex. A1-T4-S2 and Ex. A1-T4-S3. Second, OPG is subject to a Memorandum of Agreement with its shareholder, the Province of Ontario, as well as directives from its shareholder which substantially influence the nature and manner of OPG's operations. Information with respect to the Memorandum of Agreement is found at Ex. A1-T4-S1. OPG has, for example, been directed by the Province to examine both refurbishment of existing nuclear generating units and the approval of new nuclear units at an existing site. Third, in 2006 approximately 72 percent of the output from the prescribed facilities was produced by nuclear generation. The nuclear industry stands apart from most other regulated businesses due to the complexity of the technology and the overarching importance of safety. All of OPG's nuclear operations are comprehensively regulated by the CNSC. Further details on nuclear regulation of OPG is found at Ex. A1-T6-S1.

REGULATORY FRAMEWORK GOVERNING THE PRESCRIBED FACILITIES

OPG is prescribed by Ontario Regulation 53/05, as amended, as a generator for the purposes of section 78.1 of the Act. Under section 78.1, OPG receives payments for units at generating facilities in amounts that are prescribed by the Regulation until at least April 1, 2008 and, following the first order of the OEB, in the amounts the OEB determines to be just and reasonable.

Section 6 of the Regulation establishes rules governing the determination of payment amounts by the OEB. The rules authorize the OEB to establish the methodology for determining payment amounts. The OEB engaged in consultations on the methodology for determining payment amounts for OPG beginning on March 21, 2006 and on November 30, 2006 issued a report in EB-2006-0064 entitled "A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc." In this report, the OEB concluded that the regulatory methodology to be used to set initial payment amounts for the prescribed generation facilities would be a cost of service review, focusing on operations, maintenance, and administration costs and rate of return on equity as well as the particular matters required to be addressed by the Regulation.

Apart from the specific items prescribed by the Regulation, it is clear from section 78.1 of the Act that the OEB is charged with determining payment amounts that are just and reasonable. The concept of just and reasonable rates (or, in this case, payment amounts) is a familiar one in the field of utility regulation. Sections 36 (gas distribution, transmission, and storage) and 78 (electricity distribution and transmission) of the Act also establish the requirement that rates for those services be just and reasonable. Ontario is but one of many jurisdictions in Canada and the United States which has adopted the just and reasonable standard for rate setting.

It is well established at common law that the phrase "just and reasonable" in the context of setting payment amounts means payments which are fair to the consumer on one hand and which will yield fair compensation to the utility on the other. These two principles are also embodied in the OEB's objects regarding the regulation of electricity: 1) the protection of consumer interests and 2) facilitating a financially viable electricity industry.

Fair compensation to the utility encompasses two key elements: first, the right to recover all prudently incurred costs of providing the service (where prudence is evaluated without the benefit of hindsight but on the basis of information that was reasonably available to management at the time the relevant decisions were made); and, second, the right to a fair return on invested capital. A fair return on capital, in this context, means that the company will be allowed the opportunity to recover in its rates a return on the capital invested in its enterprise equivalent to the return which shareholders would receive from investing in other securities possessing an attractiveness, stability, and certainty equal to that of the company's enterprise.

The dual requirement that OPG recover prudently incurred costs and a fair return is essential to the preservation of its financial integrity. This is because OPG must be able to raise the money it needs to safely and reliably operate, maintain, and develop the prescribed facilities.

FUNDAMENTAL COST DRIVERS FOR OPG

1. A Financially Sustainable and Commercial Enterprise

In accordance with the Memorandum of Agreement from its shareholder, OPG is required to operate as a financially sustainable and commercial enterprise. OPG requires significant financial resources to fund required capital improvement projects and related maintenance programs at the prescribed facilities. OPG is, therefore, seeking a fair rate of return on the prescribed assets. The current payment amounts were established on the basis of a forecast five percent return on equity. At the time, it was acknowledged that a five percent return on equity was significantly less than the appropriate return for regulated utilities in North America[1]. A move to a commercial rate of return is required for OPG to operate as a financially sustainable and commercial enterprise in accordance with the Memorandum of Agreement and to raise the money it needs to discharge its obligation to operate, maintain, and expand the prescribed facilities safely and reliably.

2. The Cost of Operating and Maintaining the Prescribed Facilities

The prescribed facilities play a key role in supplying the Province's electricity needs and thus are fundamental to a stable, reliable electricity supply for residential, commercial, and industrial consumers. Accordingly, payment amounts set by the OEB must be sufficient to cover the cost of operating, and maintaining the prescribed assets so they can continue to

[1] *Ontario Government Announces Prices on Electricity from Ontario Power Generation,* Ministry of Energy Backgrounder, Feb. 23, 2005

fulfill this essential role and provide the greatest benefit to the people of Ontario. Because the prescribed assets provide baseload generation, they are part of the fundamental underpinning to the Ontario Power Authority's Integrated Power System Plan, which is currently before the OEB. In this context, the efficient, cost-effective, and reliable operation of the prescribed assets is critical to the reliability and security of the electricity system.

OPG is required to meet stringent nuclear safety requirements pursuant to the *Nuclear Safety and Control Act* as well as to meet all requirements of the nuclear regulator, the Canadian Nuclear Safety Commission. With respect to the regulated hydroelectric facilities, OPG is required to comply with a myriad of complex and overlapping legislative regimes satisfying both federal and provincial regulators as detailed in Ex. A1-T6-S1 and Ex. A1-T4-S2.

Beyond this, OPG is mandated by the Memorandum of Agreement to operate in accordance with the highest corporate standards, including corporate governance, social responsibility, and corporate citizenship, as well as environmental stewardship.

The task of operating within the confines of the extensive regulatory environment and the Memorandum of Agreement is made even more complex by the fact that the prescribed facilities are aging. For example, OPG's nuclear stations contain the first large-scale commercial CANDU units ever built, the result being that many of the technological issues OPG faces are being addressed for the first time ever in the nuclear industry.

In addition, although all ten of OPG's nuclear units are CANDU reactors, they reflect three generations of design philosophy and technology, as the reactors were each built in a different decade (Pickering A in the 1960's; Pickering B in the 1970's, and Darlington in the 1980's). Each station, therefore, differs from the others with respect to technology and design. Again, this adds complexity and attendant cost to station operations, while limiting OPG's ability to integrate operations and achieve economies in the operation and maintenance of these facilities.

Another aspect of nuclear operations creating cost pressures is the need to fund OPG's long-term used fuel and plant decommissioning obligations. OPG has specific contractual obligations to the Province of Ontario to fund the safe long-term storage of used fuel and nuclear plant decommissioning. Increased production forecasts and updated financial assumptions required by applicable accounting standards have caused the cost of OPG obligations to the Province in this area to increase. Details of OPG's nuclear waste management and decommissioning obligations are at Ex. H1-T1-S1.

OPG's regulated hydroelectric stations are also aging, with the result that there is an increased need for work programs to maintain, improve, and refurbish these facilities over their life cycle. Specific examples include:

- Saunders is 49 years old and requires extensive instrumentation and ongoing monitoring of concrete "growth" associated with alkali-aggregate reaction at the station.
- Sir Adam Beck I is 85 years old and the "power train" equipment is reaching end of life. It requires rehabilitation or replacement.
- Sir Adam Beck Pump Generating Station, in addition to its role in pumping water for use during peak periods, is used to control the cross over elevation of the Sir Adam Beck canals, to assist in automatic generation control, as well as to provide flexibility and optimization of operations at the Sir Adam Beck complex. This complex and unique role leads to wear and tear resulting in increased maintenance costs.
- DeCew Falls I is108 years old and a major overhaul of some of the units is required.

OPG is also experiencing aging workforce demographics and a shortage of skilled workers. Over 30 percent of OPG's workforce is expected to retire in the next four years. OPG's business operations require a highly skilled workforce. OPG simply cannot wait until one worker retires before another is hired. The lead time for training skilled workers can extend, in some cases, up to eight years. OPG must, therefore, actively manage its need for skilled, fully-trained workers to replace the significant numbers of employees expected to retire over the next few years.

Approximately 90 percent of OPG's workforce is unionized. Much of OPG's labour costs for the test period are determined by existing contracts. The details of what OPG is doing to manage labour costs are set out in Ex. F3-T4-S1.

The demographics of OPG's large workforce also creates significant financial obligations for the funding of employee pension and benefit plans, both of which are subject to the collective bargaining regime. In addition, changes in investment return and interest rate assumptions required by applicable actuarial standards are having a significant impact on the cost of these funding obligations during the test period.

3. Developing Additional Supply

OPG is also pursuing major projects to increase output or generating capacity at the prescribed facilities. For example, on June 16, 2006 OPG was directed by the Province to begin feasibility studies on refurbishing its existing nuclear units, including an environmental assessment on Pickering B, and to begin a federal approvals process, including environmental assessment, for new nuclear units at an existing site. In addition, OPG is undertaking a refurbishment of one of the older generating units at Sir Adam Beck I to increase both its capacity and output.

4. Safety

OPG places an extremely high priority on safety. OPG's Board of Directors has approved policies in the areas of health and safety, nuclear safety, and dam safety all of which have a direct impact on the operation of the prescribed facilities. These Board mandated safety policies emphasize OPG's commitment to a culture of safety, with the goal of ensuring the health and safety of its employees, contractors performing work on behalf of OPG and members of the public.

In the nuclear context, safety is a cost driver. OPG is required to meet stringent nuclear safety requirements as a condition of its operating licenses at the nuclear facilities. In addition, OPG has established a positive safety culture which ensures that nuclear plant safety is the overriding priority and that prudent and necessary resources are devoted to ensuring the safe operation of its nuclear facilities. With respect to radiation protection, for example, OPG operates under the “ALARA” principle which requires that radiation exposure be controlled, not only to regulatory requirements, but to a level that is As Low As Reasonably Achievable.

RECOVERY PURSUANT TO ONTARIO REGULATION 53/05

The Regulation specifies a number of costs that must be recovered through the payment amounts (see Exhibit J). These include:

- Any balance recorded in the variance account for differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions, to the extent that the Board is satisfied that the costs recorded in the account were prudently incurred and are accurately recorded in the account (section 6 (2) 1).
- Any balance in the Pickering A Generating Station Return to Service deferral account (section 6 (2) 3).
- Any balance in the nuclear liability deferral account (section 6 (2) 7).
- Costs and firm financial commitments incurred for investments to increase the output of, refurbish or add operating capacity to a nuclear or regulated hydroelectric generating facility if they were within the budgets approved for the projects by the OPG Board of Directors or, if not, where the OEB is satisfied that they were prudently incurred (section 6 (2) 4).
- Costs and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear facilities, where the OEB is satisfied they were prudently incurred (section 6 (2) 4.1).
- All of the costs OPG incurs in connection with the Ontario Nuclear Funds Agreement (section 6 (2) 8).
- All of the costs OPG incurs with respect to the Bruce Generating Stations and the excess earnings over cost from the lease of the Bruce Generating Stations shall be applied to reduce the revenue requirement of the nuclear generating facilities (section 6 (2) 9, 10).

Finally, in addition to the specific costs referenced above, the OEB must accept the values from the most recently audited financial statements for assets and liabilities; the revenues earned and costs associated with the Bruce Generating Stations lease; capital cost allowances; the revenue requirement impact of accounting and tax policy decisions; and capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a nuclear or regulated hydroelectric generating facility (section 6 (2) 5, 6).

DRIVERS OF REVENUE DEFICIENCY

OPG has forecast a total revenue deficiency of $1029.2M for its prescribed facilities for the 21 month test period starting April 1, 2008 - December 31, 2009. This consists of $244.6M for the regulated hydroelectric facilities and $784.6M for the nuclear facilities over the test period. (Ex. A1-T3-S1 Tables 1 - 3). There are a number of key drivers of this revenue deficiency which are discussed below.

1. Return on Equity

A major driver of total revenue deficiency results from the move to a commercial rate of return and capital structure. OPG is seeking a return on common equity that reflects the business risks associated with its regulated operations.

2. Nuclear Liabilities

A significant portion of the nuclear revenue deficiency is attributable to the revenue requirement impact of increased nuclear liabilities. These costs relate to the handling and storage of used fuel and low and intermediate level waste and the eventual safe shutdown and decommissioning of OPG's nuclear plants. During the fourth quarter of 2006, the liability increased by $1,386M as a result of updated cost estimates under an Approved Reference Plan under the Ontario Nuclear Funds Agreement. The Regulation established a deferral account for the recovery of the revenue requirement impact of the increase in the liability during the interim period. This revenue requirement impact of the nuclear liabilities is considered in Ex. H1-T1-S2.

3. Operating Cost Increases

Other Post Employment Benefits Interest Cost

The OM&A expenses in the proposed revenue requirement reflect the inclusion of interest on

OPG's OPEB obligations. Although the development of the current interim rates did not include this interest component; recognition of this expense in the revenue requirement is consistent with Generally Accepted Accounting Principles and OPG's financial statements, which include the interest component in OPEB costs.

OM&A Costs

The chief contributors to these increases in connection with the nuclear facilities are escalation in labour costs, increased pension and other post-employment benefit costs, and additional expenditures for new initiatives such as:

- Planning and preparation for the development of proposed new nuclear facilities.
- Improving material condition of plants.
- Safe storage of Pickering A Units 2 and 3.
- Addressing the demographic challenges of OPG's aging workforce and the shortage of skilled replacements for those scheduled to retire.
- Transitioning to a 36 month outage strategy at Darlington.

Many of the same issues are creating upward cost pressures on regulated hydroelectric OM&A costs, including escalating labour costs; increased pension and other post-employment benefits costs; expenditures to enhance civil works; and increased investment in hiring and training to address emerging demographic and skilled labour challenges.

Fuel and Gross Revenue Charges

Fuel and related costs increase primarily as a result of increased nuclear fuel costs due to increasing world prices for raw uranium.

Other Costs

Other costs consist of depreciation, interest, income, property and capital taxes, and are offset by other revenues. Decreases in these costs have reduced the revenue requirement in regulated hydroelectric and nuclear. The main contributors to these reductions are reductions in depreciation, interest and return on equity due a lower asset base; and reduced depreciation due to extended nuclear service lives. These are partly offset by reductions in expected ancillary and net Bruce Lease revenues.

Mitigation of the revenue requirement increase during the test period is proposed through accelerated application of tax losses to reduce the test period revenue requirement, resulting in a decrease in payment amount increases from 19.0 percent to 14.8 percent (Ex. K1-T1-S2). The end result of OPG's proposed increase in payment amounts is a less than three percent increase in consumer's monthly electricity bills (Ex. K1-T1-S3).

TIMING OF NEW PAYMENT AMOUNTS

The revenue requirement for the test period is the forecast level of revenue that will provide OPG with an opportunity to recover its costs and to earn a fair return with respect to the prescribed facilities, thereby resulting in just and reasonable payment amounts for the 21 month period ending December 31, 2009. In order that the required revenue is available to offset the expected cost of service for the prescribed generating facilities during this period, the revised payment amounts must be effective beginning on April 1, 2008. OPG is therefore seeking an order of the OEB making OPG's current payment amounts interim as of April 1, 2008 and an order setting payment amounts that will recover the full amount of OPG's revenue requirement during the test period.

OPG operates on an accounting year ending December 31 for financial reporting purposes. In order to accommodate April 1, 2008 as the effective date of the OEB's first order for payment amounts, OPG developed forecasts for the two-year period 2008 - 2009 and made adjustments to back-out costs and production for the period January 1 – March 31, 2008. The forecasts presented in this Application are all based on annual data to permit comparisons of year-over-year trends and are consistent with OPG's business planning process and fiscal year. The adjustments from a 24 month forecast to a 21 month test period for determination of the requested payment amounts are presented in Exhibit K. OPG anticipates that future applications will be based on a two year test period beginning on January 1 of the first year and ending on December 31 of the second year. This will allow OPG to align its test period with its fiscal year.

To address OPG's need for additional revenues and to smooth the implementation of the new payment amounts for consumers, OPG is seeking interim increases to current payment amounts, effective April 1, 2008, of approximately half of the full payment amount increases requested in this application.

OPG is planning on filing 2007 actual financial results in March 2008, once OPG's 2007 audited financial statements have been approved by the Board of Directors. Additional information to update the application to reflect material changes may be provided at that time.

Table 1
Summary of Revenue Requirement - Regulated Hydroelectric ($M)
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	2008[1] Annual	2008[1] Adjustment[2]	2008[1] Apr. 1-Dec. 31	2009[1]	Test Period
		(a)	(b)	(c)	(d)	(e)
	Rate Base					
1	**Net Fixed Assets**	3,863.1	(5.2)	3,857.8	3,847.5	N/A
2	**Working Capital**	0.6	0.0	0.6	0.6	N/A
3	**Cash Working Capital**	21.8	0.0	21.8	21.8	N/A
4	**Total Rate Base**	3,885.5	(5.2)	3,880.2	3,869.9	N/A
	Capitalization					
5	**Short-term Debt**	99.4	0.0	99.4	99.6	N/A
6	**Long-Term Debt**	1,551.9	(2.3)	1,549.7	1,545.0	N/A
7	**Common Equity**	2,234.1	(3.0)	2,231.1	2,225.2	N/A
8	**Total Capital**	3,885.5	(5.3)	3,880.2	3,869.9	N/A
	Cost of Capital					
9	**Short-term Debt**	5.8	0.0	5.8	6.0	11.8
10	**Long-Term Debt**	89.3	(23.8)	65.4	91.5	156.9
11	**Return on Equity**	234.6	(58.9)	175.7	233.6	409.3
12	**Total Cost of Capital**	329.7	(82.7)	246.9	331.1	578.0
	Expenses					
13	**OM&A**	119.0	(25.9)	93.1	119.0	212.0
14	**GRC**	228.2	(48.3)	179.9	244.1	423.9
15	**Depreciation & Amortization**	63.0	(15.6)	47.4	63.6	111.0
16	**Property and Capital Taxes**	8.7	(2.2)	6.5	8.7	15.2
17	**Total Expenses**	418.9	(92.1)	326.8	435.4	762.2
19	**Less: Ancillary and Other Revenue**	32.4	(8.1)	24.3	33.1	57.4
20	**Income Tax**	0.0	0.0	0.0	0.0	0.0
21	**Revenue Requirement**	716.2	(166.7)	549.5	733.3	1,282.8

1 All data sourced from Ex K1-T1-S1 Table 1 and Ex. K1-T1-S1 Table 2.
2 Adjustment to remove activity from January 1, 2008 to March 31, 2008 as described in Ex. K1-T1-S1.

Numbers may not add due to rounding.

Table 2
Summary of Revenue Requirement - Nuclear ($M)
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	2008[1] Annual	2008[1] Adjustment[2]	2008[1] Apr. 1-Dec. 31	2009[1]	Test Period
		(a)	(b)	(c)	(d)	(e)
	Rate Base					
1	**Net Fixed Assets**	2,794.0	(6.3)	2,787.7	2,696.0	N/A
2	**Working Capital**	705.4	0.0	705.4	771.8	N/A
3	**Cash Working Capital**	16.0	0.0	16.0	16.0	N/A
4	**Total Rate Base**	3,515.4	(6.3)	3,509.1	3,483.8	N/A
	Capitalization					
5	**Short-term Debt**	89.9	0.0	89.9	89.7	N/A
6	**Long-Term Debt**	1,404.1	(2.7)	1,401.4	1,390.9	N/A
7	**Common Equity**	2,021.4	(3.6)	2,017.7	2,003.2	N/A
8	**Total Capital**	3,515.4	(6.3)	3,509.1	3,483.8	N/A
	Cost of Capital					
9	**Short-term Debt**	5.2	0.0	5.2	5.4	10.6
10	**Long-Term Debt**	80.8	(21.6)	59.2	82.4	141.5
11	**Return on Equity**	212.2	(53.3)	158.9	210.3	369.2
12	**Total Cost of Capital**	298.3	(74.9)	223.3	298.1	521.4
	Expenses					
13	**OM&A**	2,184.6	(521.9)	1,662.7	2,168.7	3,831.4
14	**Fuel**	162.4	(36.7)	125.7	204.2	329.9
15	**Depreciation & Amortization**	350.1	(72.8)	277.2	388.9	666.1
16	**Property and Capital Taxes**	21.8	(5.5)	16.3	22.0	38.4
17	**Total Expenses**	2,718.8	(636.8)	2,082.0	2,783.8	4,865.7
	Less:					
	Other Revenues					
18	**Bruce Lease Revenues Net of Direct Costs**	69.1	(17.4)	51.8	82.6	134.3
19	**Ancillary and Other Revenue**	65.5	(16.0)	49.4	50.9	100.3
20	**Total Other Revenues**	134.6	(33.4)	101.2	133.4	234.6
21	**Income Tax**	0.0	0.0	0.0	0.0	0.0
22	**Revenue Requirement**	2,882.5	(678.4)	2,204.1	2,948.4	5,152.5

1 All data sourced from Ex K1-T1-S1 Table 1 and Ex. K1-T1-S1 Table 2.
2 Adjustment to remove activity from January 1, 2008 to March 31, 2008 as described in Ex. K1-T1-S1.

Table 3
Summary of Revenue Deficiency by Production Technology
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Regulated Hydroelectric 2008 (Apr. 1-Dec. 31)	Regulated Hydroelectric 2009	Regulated Hydroelectric Test Period	Nuclear 2008 (Apr. 1-Dec. 31)	Nuclear 2009	Nuclear Test Period
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Production (TWh)[1]**	12.9	18.5	31.5	38.3	49.9	88.2
2	**Prescribed Payment Amount ($/MWh)[2]**	33.0	33.0	33.0	49.5	49.5	49.5
3	**Indicated Production Revenue ($M)**	427.1	611.1	1,038.1	1,897.7	2,470.2	4,367.9
	(line 1 * line 2)						
4	**Revenue Requirement ($M)[3]**	549.5	733.3	1,282.8	2,204.1	2,948.4	5,152.5
5	**Revenue Requirement Deficiency ($M)**	122.4	122.3	244.6	306.4	478.2	784.6
	(line 4 - line 3)						

1 From Ex. K1-1-1 Table 3. Production from January 1, 2008 to March 31, 2008 has been removed as described in Ex. K1-T1-S1.
2 From O.Reg. 53/05
3 From Ex. K1-T1-S1 Table 1 (2008) and Ex. K1-T1-S1 Table 2 (2009)

OVERVIEW OF OPG

1.0 PURPOSE

This evidence provides an overview of OPG, including a brief description of OPG's corporate history, an overview of its key assets, operations, corporate governance and organization, and an explanation of OPG's mandate and objectives. This information is intended to provide context that is relevant to understanding the evidence presented within the Application. OPG's hydroelectric and nuclear businesses are described in a similar manner in Ex. A1-T4-S2 and Ex. A1-T4-S3, respectively.

2.0 CORPORATE OVERVIEW

OPG is an electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generation assets, while operating in a safe and environmentally responsible manner.

OPG was incorporated on December 1, 1998 under the *Ontario Business Corporations Act*. The generating assets of OPG's predecessor, Ontario Hydro, along with related liabilities, were subsequently transferred to OPG in April 1999. OPG's sole shareholder is Her Majesty the Queen in Right of the Province of Ontario, as represented by the Minister of Energy. OPG's head office is located in the City of Toronto.

OPG owns a diversified portfolio of electricity generating facilities. In 2006, OPG assets generated approximately 70 percent of the electricity consumed in Ontario. As of December 31, 2006, OPG's generating portfolio had 22,147 MW of total in-service capacity, comprised of the following:

- Three nuclear generating stations, with 6,606 MW capacity.
- 64 hydroelectric generating stations, with 6,956 MW capacity.
- Five fossil generating stations, with 8,578 MW capacity.
- Three wind generating stations (one of which is co-owned with Bruce Power), with 7 MW capacity.

In addition to the above:

- The Bruce A and B Generating Stations are owned by OPG but leased on a long-term basis to Bruce Power L.P.
- OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach gas-fired generating station.
- OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre, a gas-fired generating station that is now under construction.

The prescribed facilities which are the subject of this Application consist of three nuclear generating stations and six hydroelectric generating stations for a combined generating capacity of 9938 MW. The prescribed facilities are:

- Niagara Plant Group, comprised of:
  - Sir Adam Beck I Generating Station (447 MW capacity)
  - Sir Adam Beck II Generating Station (1499.2 MW capacity)
  - Sir Adam Beck Pump Generating Station (174 MW capacity)
  - DeCew Falls I and II Generating Station (166.8 MW capacity)
- R. H. Saunders Generating Station (1045 MW capacity)
- Pickering A Generating Station (1030 MW capacity)
- Pickering B Generating Station (2064 MW capacity)
- Darlington Generating Station (3512 MW capacity)

The locations of the regulated facilities and other OPG facilities are illustrated in the map provided at Appendix A.

In 2006, the regulated hydroelectric facilities represented 3,332 MW or 15 percent of OPG's in-service generation capacity and generated 18.3 TWh or 17 percent of OPG's energy production. The nuclear facilities represented 6,606 MW or 30 percent of OPG's in-service capacity and generated 46.9 TWh or 45 percent of OPG's energy production. Together the prescribed facilities represent 45 percent of the total generating capacity in the Province of

Ontario. Further details on the regulated facilities are provided in Ex. A1-T4-S2 and Ex. A1-T4-S3.

In addition to generating electricity for sale to the IESO-administered market, OPG's prescribed assets enable the sale of ancillary products to the IESO markets, including operating reserve, voltage control/reactive support, black start capability, and automatic generation control. Revenues associated with sales of ancillary products from the regulated facilities to the IESO markets are considered in Exhibit G Other Revenues.

3.0 OPG GOVERNANCE AND ORGANIZATION

OPG's Board of Directors are appointed by the shareholder. The Board of Directors currently has twelve members, who bring substantial expertise in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government, and public relations. The Board of Directors (the "Board") has established the following committees of the Board to focus on areas critical to the success of the Company:

1. Audit and Risk Committee: This Committee is responsible for reviewing the Company's regulatory filings including financial statements, management discussion and analysis, and press releases prior to their disclosures to the public. This Committee is also responsible for overseeing the internal audit function, the work of external auditors including their nomination and compensation, that the Company has adequate controls in the financial reporting process and the risk management process, and is in compliance with regulatory and internal policies.

2. Governance and Nominating Committee: This Committee develops governance principles for OPG that are consistent with high standards of corporate governance and reviewing and assessing on an ongoing basis OPG's system of corporate governance with a view to maintaining these high standards. This Committee also identifies and recommends candidates for election or appointment to the Board to be put before the shareholder in the event of a vacancy on the Board.

3. Nuclear Operations Committee: This Committee is responsible for oversight of safe and efficient operations of OPG's nuclear business, regulatory compliance of OPG's nuclear facilities, review of reports from independent oversight of OPG's nuclear operations, reviews of OPG nuclear management and organization matters, security of OPG's nuclear facilities and substances, and oversight of OPG's nuclear waste and decommissioning liabilities and management.

4. Investment Funds Oversight Committee: This Committee assists the Board in fulfilling its responsibilities for the OPG pension fund, the used fuel fund, and decommissioning fund. The Committee provides oversight of the investment of assets, investment-related liabilities, and the management of any surplus (deficit) of the funds.

5. Compensation and Human Resources Committee: This Committee focuses on human resources related areas including compensation practices, CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review including succession planning, human resources policies related to employee complaints, diversity and pay equity, organizational design, labour relations, pension plans and policies, and Board compensation, education and evaluation programs.

6. Major Projects Committee: This Committee assists the Board in providing oversight of major non-nuclear electricity supply projects, including project development, contracting, financing, and construction monitoring.

7. Nuclear Generation Projects Committee: This Committee was formed in 2006 following direction from the shareholder to: (1) begin feasibility studies on refurbishing its existing nuclear units, and (2) to begin a federal approvals process, including an environmental assessment, for new nuclear units at an existing site. This Committee assists the Board in providing oversight of the new nuclear plant projects and the refurbishment and life extension projects for existing nuclear plants.

OPG's senior management team is led by OPG's President and Chief Executive Officer, who is also a member of the Board of Directors. Reporting to the President from the operations side of the company is the Executive Vice President and Chief Operating Officer. There are five business units that report to the Chief Operating Officer: Nuclear, Nuclear Waste Management, Nuclear Generation Development and Services, Hydroelectric, and Fossil. The nuclear business units and the hydroelectric business unit, which are the subject of this Application, are described in greater detail at Ex. A1-T4-S2 and Ex. A1-T4-S3.

On the corporate side of the company, reporting directly to the President, are the various functions that provide the necessary support to the operational business units. These include functions such as Corporate Finance, Human Resources, Law, Energy Markets, and Corporate Affairs. Please refer to the organizational chart provided at Ex. A1-T5-S1 for further detail.

4.0 OPG MANDATE AND OBJECTIVES

In addition to being governed by the various policies established by OPG's Board of Directors and its senior management, such as in the areas of safety, disclosure and the environment, OPG is subject to the terms of a Memorandum of Agreement between the shareholder and OPG, dated August 17, 2005 (the "Memorandum of Agreement"), which sets out the shareholder's expectations regarding OPG's mandate, governance framework, generation performance and investment, financial framework and communications. The Memorandum of Agreement articulates the shareholder's expectation that "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." The Memorandum of Agreement is provided in Appendix B.

In accordance with the Memorandum of Agreement, OPG is obligated to focus on its core business of electricity generation and to operate its generating assets as efficiently and cost-effectively as possible, within the applicable legislative and regulatory frameworks and while mitigating risk to the Province. The Memorandum of Agreement specifically calls upon OPG to continue to operate with a high degree of vigilance with respect to nuclear safety, to seek continuous improvement in its nuclear generation business, as well as to improve and invest in existing and new hydroelectric generating capacity. Importantly, the Memorandum of Agreement also obligates OPG to operate "in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship", as well as "in accordance with the highest of corporate standards for environmental stewardship."

The Memorandum of Agreement further states that the shareholder may at times direct OPG to undertake special initiatives, which will be communicated as written declarations by way of a Unanimous Shareholder Agreement, or directives, in accordance with section 108 of the *Ontario Business Corporations* Act and made public. As of the date of this Application, OPG had received five such directives. While three of the directives are not relevant to this Application, an October 14, 2005 directive related to the Bruce Power Lease Agreement and a June 16, 2006 directive related to 'refurbishment' feasibility studies and beginning federal approvals processes, including an environmental assessment, for 'new nuclear' are significant. In response to the Memorandum of Agreement and directives, as well as other government procurement efforts aimed at ensuring sufficient electricity supply, OPG is pursuing several major projects to increase generating capacity at the prescribed facilities.

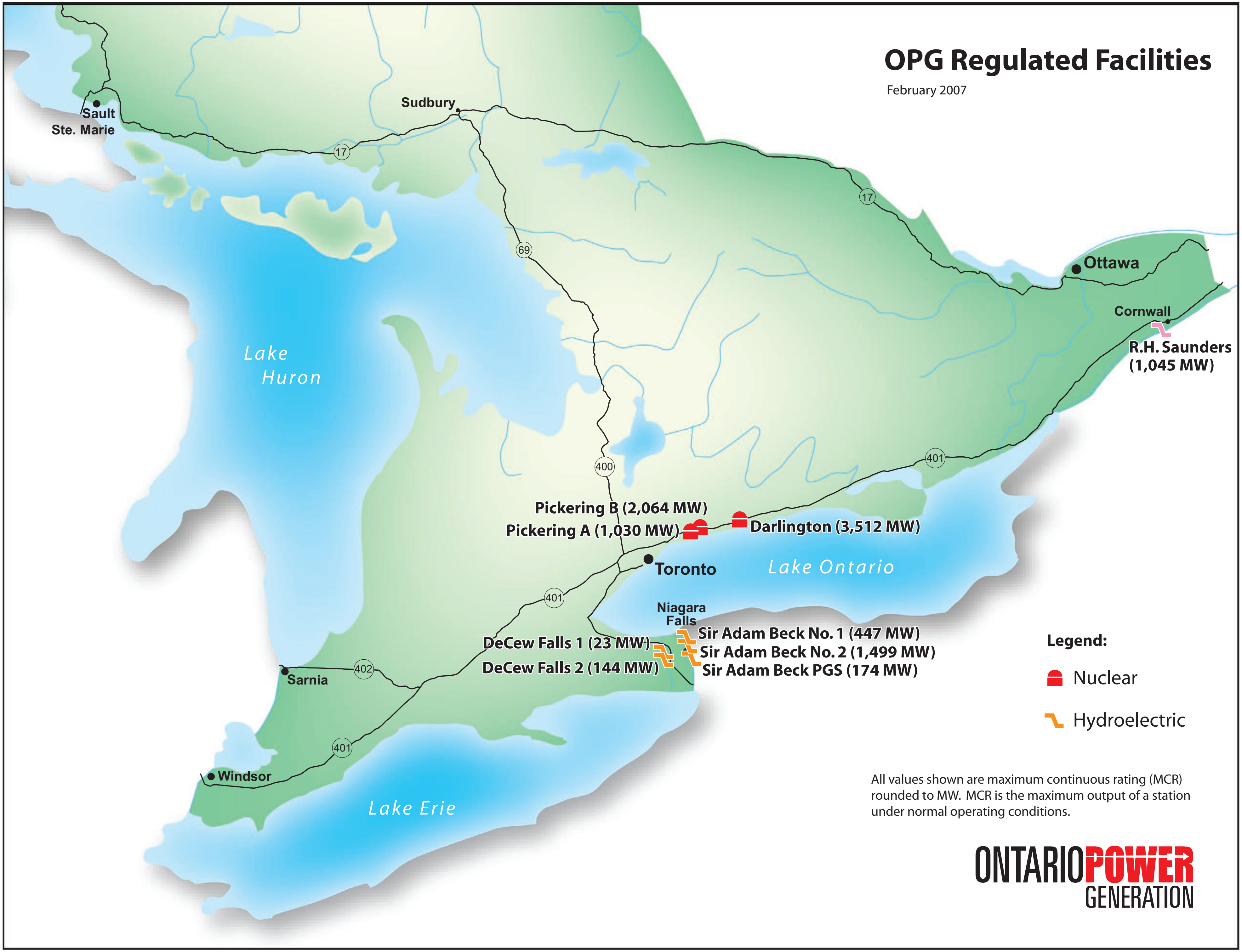
OPG is focused on the following corporate strategies for accomplishing its mandate and objectives:

- Improving its generating asset performance.
- Increasing its generating capacity.
- Achieving financial sustainability.
- Achieving excellence in corporate governance, safety, social responsibility, corporate citizenship, and environmental stewardship.

LIST OF ATTACHMENTS

Appendix A: Map showing locations of the regulated facilities and other OPG facilities

Appendix B: Memorandum of Agreement between the Shareholder and OPG


OPG Regulated Facilities
February 2007
Sault Ste. Marie
Sudbury
Ottawa
Cornwall
R.H. Saunders (1,045 MW)
Lake Huron
Pickering B (2,064 MW)
Pickering A (1,030 MW)
Darlington (3,512 MW)
Toronto
Lake Ontario
Niagara Falls
Sir Adam Beck No. 1 (447 MW)
Sir Adam Beck No. 2 (1,499 MW)
Sir Adam Beck PGS (174 MW)
DeCew Falls 1 (23 MW)
DeCew Falls 2 (144 MW)
Sarnia
Windsor
Lake Erie
17
69
400
401
402
Legend:
Nuclear
Hydroelectric
All values shown are maximum continuous rating (MCR) rounded to MW. MCR is the maximum output of a station under normal operating conditions.
ONTARIO POWER GENERATION

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 <u>Governance Framework</u>

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. <u>Generation Performance and Investment Plans</u>

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. Financial Framework

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. Communication and Reporting

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

OVERVIEW OF REGULATED HYDROELECTRIC FACILITIES

1.0 PURPOSE

The purpose of this evidence is to provide a description of the regulated hydroelectric facilities, an overview of the hydroelectric mandate, objectives, organization, management framework, key performance targets, benchmarking, as well as a discussion of key regulations, agreements and programs.

2.0 DESCRIPTION OF REGULATED HYDROELECTRIC FACILITIES

OPG's regulated hydroelectric facilities consist of the Niagara Plant Group generating stations (Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station ["PGS"], DeCew Falls I and DeCew Falls II) and the R.H. Saunders Generating Station ("Saunders").

Chart 1 presents some basic facts about the regulated hydroelectric facilities.

Chart 1

Regulated Hydroelectric Facilities Basic Information

River System	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)	Original Unit In-Service Dates
Niagara Region	Sir Adam Beck I	9	447	1922 – 1930
	Sir Adam Beck II	16	1,499	1954 – 1958
	Sir Adam Beck PGS	6	174	1957 – 1958
	DeCew Falls I and II	6	167	1898 – 1948
St. Lawrence River	R.H. Saunders	16	1,045	1958 – 1959

The Niagara Plant Group facilities and Saunders are situated on two different drainage sub-basins within the Great Lakes/St. Lawrence River system. Sir Adam Beck and DeCew Falls operate on water from Lake Erie/Niagara River. R.H. Saunders utilizes water from the St. Lawrence River.

The Sir Adam Beck and DeCew Falls facilities form the Niagara Plant Group. They are controlled from a single control centre located at Sir Adam Beck I. R.H. Saunders is part of the Ottawa St. Lawrence Plant Group, which also includes nine unregulated OPG hydroelectric facilities on the Ottawa River and Madawaska River systems. It is operated from a control centre within the station (see photos of stations in Appendix A).

Sir Adam Beck Facilities

Sir Adam Beck I Generating Station

The Sir Adam Beck I Generating Station consists of ten hydroelectric generating units (seven in-service 60 Hz units, two in-service 25 Hz units, and one de-registered 25 Hz unit) and a frequency changer. The station receives water drawn from the upper Niagara River via the Welland River and through a man-made open-cut canal that travels through the City of Niagara Falls. Water is discharged from the station into the Lower Niagara River.

Sir Adam Beck II Generating Station

Sir Adam Beck II Generating Station consists of 16 hydroelectric generating units. The station receives water drawn from the Niagara River via two 14 metre diameter tunnels under the City of Niagara Falls. The tunnels travel for 9 km surfacing at outlet portals to a single 3.5 km long open cut canal which conveys the water to the Sir Adam Beck stations. The open cut canal crosses the open cut canal for Sir Adam Beck I Generating Station at a location known as the ‘cross-over’. Water downstream of the ‘cross-over’ is capable of reaching both the Sir Adam Beck I and the Sir Adam Beck II Generating Stations. Water is discharged from Sir Adam Beck II into the Lower Niagara River.

Sir Adam Beck Pump Generating Station

The Sir Adam Beck Pump Generating Station began operating in 1957. It consists of six mixed-flow variable-pitch reversible pump-turbines. The station was designed and built for integrated operation with the other two Sir Adam Beck plants and is generally used to pump/store water during off-peak periods for use during peak periods. During off-peak periods, the station pumps water from the cross-over location of the Sir Adam Beck open cut canals into a large man-made storage reservoir. During peak demand periods it generates electricity from water stored in the reservoir and discharges the water back into the Sir Adam Beck I and Sir Adam Beck II open-cut canals at the cross-over location. The water is then utilized by the Sir Adam Beck I and Sir Adam Beck II Generating Stations.

The station also assists in providing automatic generation control and operating reserve at the Beck complex, as well as controlling the amount of water diverted from the Niagara River to the Beck complex by controlling the cross-over elevation.

Sir Adam Beck Joint Works

The use of Niagara River water for power production is governed by international treaties between Canada and the United States as detailed later in this exhibit (see section 8.1). In the 1950s, the International Niagara Control Works structure (also know as International Control Dam) was constructed to control the volume and distribution of water flow over Niagara Falls and the elevation of the upstream storage area known as the Grass Island Pool. The International Niagara Control Works structure is operated and maintained by Niagara Plant Group under Memorandum of Understanding ("Niagara MOU") between OPG and the New York Power Authority ("NYPA"). OPG and NYPA equally share the costs associated with Joint Works (as defined in the Niagara MOU) which includes the International Niagara Control Works. Details of the Niagara MOU are provided later in this exhibit (section 8.2). Operation of the International Niagara Control Works structure is monitored by the International Niagara Board of Control.

DeCew Falls I and II Generating Stations

The DeCew Falls Generating Stations produce power with water from Lake Erie diverted through the Welland Ship Canal, which is owned and operated by the St. Lawrence Seaway

Management Corporation. Water flow from the Welland Ship Canal is controlled by two intake structures. Intake #2 is a control dam used to control water flow into Lake Gibson and subsequently into both DeCew stations through a series of waterways. Intake #1 is a smaller control structure that provides water to Lake Gibson and to a Region of Niagara water treatment plant. The conveyance of water is governed under an agreement between OPG and the St. Lawrence Seaway Management Corporation and through an agreement signed in 1903 between the predecessors of OPG and the Region of Niagara. Water is discharged by both DeCew Falls stations into 12 Mile Creek, which travels through the City of St. Catharines and discharges into Lake Ontario.

DeCew Falls I is a six-unit hydroelectric station (four in-service units, two decommissioned units) that began operation in 1898. DeCew Falls II is a two-unit hydroelectric station that began operation in 1943.

R.H. Saunders Generating Station

R.H. Saunders Generating Station is a 16-unit hydroelectric station spanning half the width of the St. Lawrence River at Cornwall, Ontario. R.H. Saunders is connected to the 16-unit St. Lawrence - Franklin D. Roosevelt Generating Station, which is owned and operated by New York Power Authority. Together, the two stations span the entire St. Lawrence River. The sixteen R. H. Saunders units were placed in-service between July 1958 and December 1959 and are operated from a control room located within the station.

R.H. Saunders Joint Works

Many of the associated structures and dams which operate in conjunction with R.H. Saunders and NYPA's Franklin D. Roosevelt station are operated and maintained pursuant to Memorandum of Understanding ("St. Lawrence MOU") between OPG and NYPA. Under the St. Lawrence MOU, OPG and NYPA share equally in the costs associated with the operation and maintenance of the Joint Works (as defined in the St. Lawrence MOU). The St. Lawrence Joint Works consist of all the structures associated with the R.H. Saunders and Franklin D. Roosevelt Generating Stations including dams, headworks, dykes, Barnhart Island bridge and the ice booms, with the exception of the powerhouses.

3.0 MAJOR SUPPLY PROJECTS

OPG has initiated two major projects at the regulated hydroelectric facilities to increase the output from the Sir Adam Beck facilities. Further information on these projects is provided in Ex. D1-T1-S1.

Niagara Tunnel Project

The total flow of water available to the Sir Adam Beck Generating Stations pursuant to treaties between Canada and the United States exceeds the combined capacities of the existing water diversion facilities (i.e., the Sir Adam Beck power canal and two tunnels) that serve these stations about 65 percent of the time. To capitalize on this potential, a third tunnel has been approved by the OPG Board of Directors and is being constructed to divert the additional water from the Niagara River to the Sir Adam Beck generating stations (the "Niagara Tunnel Project"). The additional water provided by the Niagara Tunnel Project will increase the efficient utilization of the existing capacity of the stations at the Sir Adam Beck complex, thereby increasing energy production by an average of 1.6 TWh per year. Based on information provided by the contractor, the in-service date of the tunnel will be delayed from the original project completion schedule of June 2010 (see Ex. D1-T1-S1).

Sir Adam Beck I Unit 7 Frequency Conversion/Rehabilitation

At present, one of the ten units at Sir Adam Beck I (Unit G7 – 25 Hz), is decommissioned and has been deregistered with the IESO. There is an economic opportunity to rehabilitate and convert this unit from 25 Hz to 60 Hz. The additional capacity and energy from this project will be 61.5 MW and 100 GWh/year, respectively. This project has been approved by the OPG Board of Directors in 2007 is expected to be completed in 2009.

4.0 HYDROELECTRIC ORGANIZATION AND MANAGEMENT FRAMEWORK

All OPG hydroelectric facilities, including the regulated facilities are under the organizational authority of the Executive Vice President ("EVP") Hydroelectric and form part of the Hydroelectric Business Unit (subsequently referred to as Hydroelectric).

Hydroelectric utilizes a decentralized organizational model based on five plant groups – including the Niagara Plant Group and the Ottawa/St. Lawrence Plant Group of which R. H. Saunders is a part. The Plant Groups operate with a high degree of autonomy. This organizational structure includes a technical and support presence located at the plants wherever practical. The local technical and support resources in the plant groups are augmented by central support/services organizations offering specialized expertise and oversight in critical areas. Organizational charts are provided in Ex. A1-T5-S1.

The Hydroelectric Business Unit was created January 1, 2006 to strengthen the efficient and cost effective operation of the existing hydroelectric facilities, and to carry out its new mandate with respect to new hydroelectric developments, such as the Niagara Tunnel Project. Before 2006, Hydroelectric was part of OPG's Electricity Production Business Unit, which included both hydroelectric and fossil generating facilities. As part of Electricity Production, Hydroelectric shared central support functions with Fossil. These Electricity Production central support functions were unbundled and allocated to Hydroelectric and Fossil in 2006. The Plant Group structure and accountabilities did not otherwise change.

The Hydroelectric central support groups perform a dual role. First, they provide oversight and due diligence support to the EVP - Hydroelectric by setting direction through high level programs and other requirements (e.g., corporate policies). Secondly, they provide the specialized support necessary for the plant groups to make effective operational and business decisions and to achieve corporate alignment. The central support groups assist the plant groups in following corporate governance obligations in areas such as planning, asset management, engineering, environment and dam and public safety, supply chain/procurement and finance. Descriptions of the key functions and activities of Hydroelectric's central support groups are provided in Ex. F1-T2-S1 Section 2.4.

Each plant group is managed by a Plant Group Manager, who reports to the EVP - Hydroelectric. Plant Group management establishes local governance to follow the above direction and to ensure that due diligence requirements are met. They are responsible for managing all aspects of the facilities assigned to them including:

- Operations
- Maintenance
- Water management
- Asset management
- Engineering
- Project management
- Employee health and safety
- Dam and waterways public safety
- Environment
- Local public affairs/relations
- Security
- Materials management

Within this decentralized organizational model, “lead” plant groups are designated and given the accountability to champion certain common business issues, processes, special projects and/or to co-ordinate matters on behalf of Hydroelectric. Plant Groups lead in maintaining and communicating certain governing documents, procedures, and drafting documentation. This “lead” plant group model is both effective and efficient, in that it leverages the existing expertise of plant group staff in certain areas, and allows for a leaner central support organization by reducing duplication and overlap.

4.1 Hydroelectric Planning and Asset/Investment Management

Hydroelectric follows an annual business planning and budgeting process that feeds into OPG’s corporate process (see Ex. A2-T2-S1). The approaches used to identify investment and base work program requirements in support of Hydroelectric’s objectives are described below.

4.1.1 Portfolio Approach to Investment Management

Hydroelectric uses a structured portfolio approach to identify and prioritize projects for its investment program. Annual engineering reviews and plant condition assessments (conducted on a cycle of approximately five to ten years) are performed to determine short-term and long-term expenditure requirements to sustain or improve each facility. These may be followed by the preparation of a facility life cycle plan, which is performed on an as-needed basis for marginal assets or assets requiring significant expenditures relative to the value of the facility. This planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility, and direct limited corporate funds at the facilities that can best maintain or enhance the value of the hydroelectric business and OPG. The cornerstone of this approach is that safety, environmental, and other regulatory programs are of the highest priority.

4.1.2 Streamlined Reliability Centred Maintenance

Hydroelectric utilizes a process known as streamlined reliability-centred maintenance to optimize the preventive maintenance program at its facilities. The streamlined reliability-centred maintenance process provides a consistent method of identifying, scheduling and executing maintenance activities at its facilities. This is an improvement over the cyclical maintenance approach used before streamlined reliability-centred maintenance was introduced.

The concept of streamlined reliability-centred maintenance dictates that the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure (i.e., balance of cost versus risk). Streamlined reliability-centred maintenance is based on the characteristics/criticality and history of the equipment, as well as knowledge and experience of maintenance and technical personnel. Streamlined reliability-centred maintenance also provides a structured process for transferring knowledge from experienced workers to the next generation of workers (e.g., trades apprentices), thereby reducing the future demographic risks associated with the retirement of experienced staff. This experience and knowledge, as well as equipment history, characteristics and maintenance programs, are captured in a maintenance management system. By focusing maintenance and associated support resources to the right areas, the business has been able to accomplish more of its base work program (including additional regulatory requirements), thereby minimizing the need for additional resources.

5.0 HYDROELECTRIC MANDATE AND OBJECTIVES

The Memorandum of Agreement between OPG and its shareholder provides that OPG's core mandate is electricity generation. It further provides that OPG will "operate its existing nuclear, hydroelectric, and fossil generation assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada." The Memorandum of Agreement also states that "OPG will operate these assets in a manner that mitigates the Province's financial and operational risk".

With respect to investment in new generation capacity, the Memorandum of Agreement provides that "OPG's priority will be hydroelectric generation capacity" and that "OPG will seek to expand, develop and/or improve its hydro-electric generation capacity." It further states that "this will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible." The Niagara Tunnel Project and Sir Adam Beck I G7 conversion from 25 Hz to 60 Hz, which are considered in Ex. D1-T1-S1, were undertaken in response to this mandate from the shareholder.

Consistent with the mandate and OPG's corporate objectives, the Hydroelectric Business Unit has the following objectives:

- Sustain and improve the existing hydroelectric assets for the long term.
- Operate and maintain hydroelectric facilities in an efficient and cost effective manner.
- Maintain and improve reliability performance where practical and economic.
- Maintain existing excellent employee safety record (top quartile performance).
- Strive for continuous improvement in the areas of dam and waterways public safety and environmental performance.
- Seek to expand, develop, and/or improve existing hydroelectric generation where feasible.

6.0 HYDROELECTRIC KEY PERFORMANCE TARGETS

Hydroelectric establishes performance targets to support its business objectives and generally benchmarks its performance against these targets. Performance targets are described below and benchmarking information is presented in section 7.0.

Availability

Availability is a measure of the reliability of a generating unit represented by the percentage of time the unit is capable of providing service, whether or not it is actually in-service, relative to the total hours for the period in question (typically 8,760 hours). It is determined by the following equation: Availability = 100% – Incapability Factor, where incapability factor is a measure of the incapability of a unit to generate over the period in question. Incapability factor is defined as the ratio of scheduled and unscheduled outage hours and adjusted derating hours to the total hours in the period.

Equivalent Forced Outage Rate ("EFOR")

EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service, including any forced deratings, compared to the amount of time the generating unit was available to operate.

OM&A Unit Energy Cost

OM&A unit energy cost is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expense plus allocated central hydroelectric costs, divided by hydroelectric electricity generation. The gross revenue charge is excluded as this cost is not within the direct control of OPG. The gross revenue charge is dictated and determined by O. Reg. 124/02 under the *Electricity Act, 1998.*

Safety – Accident Severity Rate

OPG and the Hydroelectric Business Unit spend a significant amount of time and effort in training and awareness to ensure the safety of its employees. The accident severity rate is used as a key measure of safety performance both within Hydroelectric and across OPG. It is defined as the number of days lost by employees injured on the job divided by 200,000 hours worked. This measure is used by other electric utilities and is benchmarked by the Canadian Electrical Association ("CEA").

<u>Environmental Performance</u>

An environmental performance index is utilized by Hydroelectric to measure the environmental performance of the regulated facilities. The environmental performance index consists of three main categories:

- Spills
- Regulatory compliance (e.g., regulatory infractions)
- Energy efficiency

Hydroelectric performance targets are established on the basis of the following factors:

- Historical performance trends.
- Age and condition of facility.
- Major outages and OM&A project investments plans for the current year.
- Recent major investments to improve reliability.
- Comparison with external benchmarking.
- Continuous improvement considerations.

Targets are monitored and compared to actual data as the year progresses.

<u>Availability and Equivalent Forced Outage Rate - History and Targets</u>

Chart 2 shows reliability targets and actuals from 2004 to 2007 for each regulated plant and for the regulated plants grouped together. Chart 3a and 3b show availability and EFOR targets, respectively for 2008 and 2009. The EFOR targets for 2008 and 2009 are similar to 2007, and better than the CEA and Electric Utility Cost Group ("EUCG") averages. It should be noted that availability targets fluctuate based on the planned outage program, as well as forced outages which cannot be predicted. In 2009, availability will decline due to overlapping planned outages at Sir Adam Beck I for the rehabilitation and/or conversion of each unit at the station. Overall, availability is expected to improve in the long run as the major outages for conversions/rehabilitation of Sir Adam Beck 1 are completed.

Chart 2

Regulated Hydroelectric Facilities - History and Targets for Availability and EFOR

Measure	Name of Station/Grouping	2004 Target	2004 Actual	2005 Target	2005 Actual	2006 Target	2006 Actual	2007 Target	2007 Actual	Notes
Availability Factor (%)	DeCew Falls II	96.4	97.7	80.4	84.3	65.3	64.4	75.1	77.6	major outages and overhauls in 2006 & 2007
	SAB I	91.9	85.4	88.2	87.4	90.3	91.8	93.9	92.3	Major outages starting in 2008
	SAB II	89.5	89.5	92	94.6	96.9	97.3	96.0	96.9	Station rehabilitated and upgraded from 1996 to 2005
	SAB PGS	86.6	79.9	90.8	90.2	90.2	90.7	89.7	86.1	
	Saunders	95.3	96.4	95.7	95.9	96.6	97.4	95.3	97.3	Station rehabilitated and upgraded from 1992 to 2001
	Aggregate of all 5 regulated plants (excl. DeCew Falls I)	n/a	90.1	91.8	92.7	93.5	94.2	93.8	94.1	2007 actual is better than CEA, EUCG and NERC averages
EFOR (%) (Reliability)	DeCew Falls II	1.1	0.3	1.6	1.5	1	17.0	1.1	1.0	
	SAB I	1.7	5.1	1.6	1.7	1.9	3.2	2.0	3.7	Unit 9 on a permanent derating until rehab in 2009
	SAB II	0.7	0.02	0.70	0.2	0.5	0.1	0.5	0.4	
	SAB PGS	2.8	12.5	2.7	2.2	3.3	2.0	3.5	9.7	
	Saunders	0.7	0.1	0.7	1.6	0.5	0.0	0.6	0.0	
	Aggregate of all 5 regulated plants (excl. DeCew Falls I)	n/a	2.1	1.1	1.2	1.0	1.5	1.1	1.8	2007 actual is better than CEA, EUCG and NERC averages

Note: The availability and EFOR of DeCew Falls I is not tracked since this station basically utilizes the available water that is in excess of what can be utilized by the newer, more efficient DeCew Falls II station.

EUCG – Electric Utility Cost Group   CEA – Canadian Electrical Association

Chart 3a

Availability Targets (%)

	SAB I	SAB II	SAB PGS	DeCew Falls I	DeCew Falls II	Total Niagara	Saunders	Total
2008	95.3	96.9	81.1	n/a	93.4	93.4	96.4	94.4
2009	88.6	98.0	92.3	n/a	96.8	94.2	95.2	94.6

Chart 3b

EFOR Targets (%)

	SAB I	SAB II	SAB PGS	DeCew Falls I	DeCew Falls II	Total Niagara	Saunders	Total
2008	2.0	0.5	3.5	n/a	1.1	1.5	0.6	1.1
2009	2.0	0.5	3.5	n/a	1.1	1.5	0.6	1.1

OM&A Unit Energy Cost - History and Targets

Chart 3c shows OM&A unit energy cost targets for 2007 through 2009. These targets are based on planned OM&A expenditures divided by the energy forecast for each year. OM&A unit energy costs were not tracked in 2005 for the regulated facilities. In 2006, the actuals were better than target for both Niagara (target of 3.89 $/MWh versus actual of 3.65 $/MWh) and Saunders (target of 2.14 $/MWh versus actual of 2.06 $/MWh). In 2007, the actuals were also better than targets.

Chart 3c

OM&A Unit Energy Cost Targets ($/MWh)

	SAB I	SAB II	SAB PGS	DeCew Falls I	DeCew Falls II	Total Niagara	Saunders	Total
2007	n/a	n/a	n/a	n/a	n/a	4.4	2.5	3.7
2007 Actuals	n/a	n/a	n/a	n/a	n/a	3.9	2.1	3.2
2008	n/a	n/a	n/a	n/a	n/a	4.7	2.7	4.0
2009	n/a	n/a	n/a	n/a	n/a	4.5	2.6	3.8

Safety - Accident Severity Rate - History and Targets

Chart 3d shows accident severity rate accident severity rate targets for 2007 through 2009. These targets are based on CEA and other benchmarking, as well as OPG’s overall targets.

It is important to note that the accident severity rate has been zero days lost/200,000 hours worked at Niagara Plant Group for the past four years and zero days lost/200,000 hours worked at Saunders for the past nine years. This is considered excellent by any standard.

Chart 3d

Accident Severity Rate Targets (number of days lost/200,000 hours worked)

	SAB I	SAB II	SAB PGS	DeCew Falls I	DeCew Falls II	Total Niagara	Saunders	Total
2007	<5	<5	<5	<5	<5	<5	<5	<5
2008 through 2009	<4.5	<4.5	<4.5	<4.5	<4.5	<4.5	<4.5	<4.5

In 2007, the regulated hydroelectric facilities maintained their excellent safety record. The accident severity rate remained at zero days lost/200,000 hours.

<u>Environmental Performance Index – History and Targets</u>

Hydroelectric has a very good track record with regard to environmental performance. Environmental management systems have been in place since 2000 and are registered under the International Organization of Standardization ("ISO") 14001. The ISO 14001 registration ensures compliance with legal requirements and continual improvement of the environmental management system. Hydroelectric also has a number of environmental programs in place to manage priority environmental issues and risks in the business.

The environmental performance index for the regulated facilities has been better than the target of 100 percent from 2004 to 2007. The environmental performance index target for 2008 to 2009 is 100 percent or greater.

7.0 REGULATED HYDROELECTRIC FACILITIES BENCHMARKING

Hydroelectric benchmarks reliability, cost and safety performance with comparable businesses to assess and understand the performance of its stations, as well as to identify opportunities for improvement.

Benchmarking data provides a useful starting point to compare the costs and reliability of Hydroelectric's regulated assets to those of other hydroelectric facility owners. Because of the differing geographic locations and distribution of the plants, as well as differences in regulatory regimes, direct comparisons cannot be readily made between Hydroelectric's regulated station costs and those of other utilities. In addition, specifics of a station's design, site configuration, the number of, type of and physical dimensions of its dams, the way the station has historically been operated and maintained, and its equipment age/condition can result in its costs and reliability performance deviating, positively or negatively, on some of the benchmarking indicators. Water conditions (i.e., flows and water levels) also impact the relative benchmarking results for any particular year because they affect the amount of energy generated and ultimately have an impact on the unit energy cost ($/MWh), which are not driven by changes in costs. Thus, benchmarking results for individual plants are not definitive, and should only be used as a guide in making comparisons.

Hydroelectric uses three sources for benchmarking:

- EUCG Inc. (formerly known as Electric Utility Cost Group)
- Canadian Electrical Association ("CEA")
- Haddon Jackson Associates (acquired by Navigant Consulting in 2007)

<u>EUCG and CEA Reliability Benchmarking</u>

Hydroelectric has participated in the Generation Equipment Reliability Information System benchmarking programs carried out by the EUCG Inc. and the CEA since the mid 1990s. EUCG benchmarking includes participation by Canadian and American utilities, including Manitoba Hydro, BC Hydro, Pacific Gas & Electric, U.S. Army Corps of Engineers, U.S. Bureau of Reclamation and Bonneville Power Authority. For this benchmarking the data are not aggregated, thus individual OPG plants can be compared to the individual plants in the entire group (i.e., "quartile" analysis can be done). Nine Canadian utilities participate in the CEA benchmarking, including Hydro-Quebec, Manitoba Hydro, BC Hydro, Churchill Falls, Newfoundland and Labrador Hydro, Nova Scotia Power, Saskatchewan Power, Alcan and Aquila. The CEA benchmarking is done on an aggregate basis. OPG plants (aggregated) are compared to the aggregate of the plants in the entire group of utilities.

Benchmarking results for reliability, cost and safety are presented below.

7.1 Equivalent Forced Outage Rate and Availability

Hydroelectric benchmarks the reliability indicators of EFOR and availability using data from the EUCG and CEA.

The results of the 2003 to 2006 reliability benchmarking of the regulated hydroelectric facilities are presented in the two charts below.

Chart 4a
EUCG Reliability Benchmarking

Measure	Name of Station/Grouping	Value In 2003 & Quartile	Value In 2004 & Quartile	Value In 2005 & Quartile	Value In 2006 & Quartile
Availability Factor (%)	DeCew Falls II	97.6 (Q1)	97.7 (Q1)	84.3 (Q4)	64.4 (Q4)
	SAB I	93.9 (Q2)	85.4 (Q4)	87.4 (Q4)	91.8 (Q2)
	SAB II	91.5 (Q3)	89.5 (Q3)	94.6 (Q2)	97.3 (Q1)
	SAB PGS	92.5 (Q3)	79.9 (Q4)	90.2 (Q3)	90.7 (Q3)
	Saunders	97 (Q1)	96.4 (Q2)	95.9 (Q2)	97.4 (Q1)
Equivalent Forced Outage Rate (Reliability) (%)	DeCew Falls II	1 (Q3)	1.1 (Q2)	1.5 (Q2)	17.2 (Q4)
	SAB I	0.5 (Q3)	5.6 (Q4)	1.7 (Q2)	3.2 (Q3)
	SAB II	0.14 (Q1)	0.02 (Q1)	0.2 (Q1)	0.1 (Q1)
	SAB PGS	5.9 (Q4)	12.5 (Q4)	2.17 (Q3)	2.0 (Q3)
	Saunders	0.08 (Q1)	0.07 (Q1)	1.6 (Q2)	0.0 (Q1)

Notes: 1) EUCG includes 670 units; 2) High availability is good. Low forced outage rate is good.
3) Q1 means that a station is in the top/best quartile of the benchmarked EUCG stations.

Chart 4b

CEA Reliability Benchmarking

Measure	Name of Station/Grouping	Value In 2003	Value In 2004	Value In 2005	Comparison Details/Notes
Availability Factor (%)	Availability CEA (excluding OPG)	90.9	90.8	89.4	
	Aggregate of all 5 OPG large plants (including Beck PGS)	94.1	90.5	92.7	CEA does not provide quartile comparisons. Data is provided on aggregate basis.
Equivalent Forced Outage Rate (Reliability) (%)	Forced Outage Rate CEA (excluding OPG)	1.9	2.0	2.5	
	Aggregate of all 5 OPG large plants (including Beck PGS)	0.7	2.1	1.2	CEA does not provide quartile comparisons. Data is provided on aggregate basis.

Note: CEA benchmarking includes 692 generating units. 2006 CEA benchmarking information is not available.

The above data demonstrates that the availability and reliability for the individual and/or grouping of regulated plants, is generally better than, or comparable, to the EUCG and CEA benchmarks. It should be noted that Sir Adam Beck PGS is included in the OPG data for completeness. This station is generally inherently less reliable than conventional hydroelectric stations due to its technically complex "reversible pump turbine" design and its multi-faceted role in the electricity system (e.g., pumping, generation, automatic generation control, and water diversion control). To accomplish this role, more frequent stops and starts are required than conventional stations, leading to more wear and tear on equipment.

The two largest plants, Sir Adam Beck II and Saunders, were generally in the upper two quartiles for both availability and EFOR from 2003 to 2006. In fact the availability and EFOR of both SAB II and Saunders improved in 2006 to the point that they both attained first quartile status in the EUCG benchmarking. The availability of Sir Adam Beck II was lower in 2003 and 2004 compared to 2005 due to the planned outages to install upgraded runners and rehabilitate the units. All Sir Adam Beck II units have now been rehabilitated and upgraded (completed in 2005). As such, availability improved to 97.3 percent in 2006. The equivalent forced outage rate was .05 percent in 2006 which is in the top quartile. This is considered to be excellent performance.

The availability of DeCew Falls II in 2003 and 2004 was very good, but its EFOR was deteriorating due to the age of the units, the fact that the last major overhaul was performed over 25 years ago, as well as emerging operational problems caused by unit misalignment. Before 2003, the EFOR for this station had consistently been in the upper two quartiles. As such, major overhauls were planned to ensure continued long term reliability and performance of the station. From 2005 to 2007, DeCew Falls II has had below average availability performance due to long major planned outages to rehabilitate the two units. The outage program started in 2005 and was completed in 2007. The reliability of this station is expected to improve in 2008, as both units have now been overhauled. The operational problems, which have been prevalent since 2002, are expected to be resolved after completion of the overhauls in 2007.

With regard to Sir Adam Beck I, performance is below average for its peer group due to the age and poor condition of most of the units. One of the units (Unit 9) is derated until the unit is rehabilitated in 2008/2009. Sir Adam Beck I is slated for a full station rehabilitation starting in late 2007, including the conversion of one or more of the 25 cycle units to 60 cycle. This is expected to improve reliability at the station in the long term.

With regard to Sir Adam Beck PGS, availability and reliability has generally been in the third and fourth quartiles between 2003 and 2005. Since the station is unique in its technical design, vintage and role, there are no real comparators in the EUCG database for PGS. The reliability comparisons with the rest of the EUCG stations have been put in the above chart for information purposes only. In 2004 the rotor frame on several units exhibited unexpected severe cracking, which had to be repaired. This contributed to the very poor reliability value in 2004. Reliability in 2005 and 2006 has improved to reasonable levels. Availability was 90.1 percent in 2005 and 90.7 percent in 2006. The EFOR was 2.2 percent in 2005 and 2 percent in 2006. This is considered to be very good for this station.

7.2 OM&A Unit Energy Cost

Haddon Jackson Associates Benchmarking (now Navigant Consulting)

Hydroelectric benchmarks OM&A cost performance of its regulated stations by participating in the Hydroelectric Generation Benchmarking Program that is carried out by Haddon Jackson Associates.

Haddon Jackson Associates' benchmarking program includes over 330 stations, comprised of about 1,255 units that represents about 87,000 MW of installed capacity. The participants are predominantly in Canada (i.e., BC Hydro, Hydro-Quebec, Nova Scotia Power, Great Lakes Power, Newfoundland and Labrador Hydro) and the United States (i.e., New York Power Authority, Tennessee Valley Authority, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, Southern California Edison). The group of participating stations is diverse in size, type of facility and age, and includes a mix of run-of-the-river, reservoir, and pumped storage.

Costs included in the Haddon Jackson Associates' benchmarking are operations, plant maintenance, waterways and dam and other maintenance, support (i.e., engineering, finance, corporate support) and public affairs and regulatory. Public affairs and regulatory costs include items such as water rentals and usage fees, gross revenue charge, major environmental costs such as fish/wildlife operations and studies, as well as special licensing fees (e.g., FERC re-licencing in the U.S.).

The study results are generally segmented into various peer groupings. Drivers used to determine peer groupings include unit/station sizes, number of units, and age.

The cost benchmarking data presented is for OM&A costs only (referred to as "Partial Function Costs" in the Haddon Jackson Associates Benchmarking Program). Haddon Jackson Associates also performs a Total Cost Analysis which includes public affairs and regulatory costs, such as gross revenue charge. Public affairs and regulatory costs such as gross revenue charge are not within the control of a utility (i.e., externally dictated), thus they are not relevant when assessing and benchmarking operations, maintenance and administration costs (which are generally within management control).

For the years 2005 and 2006, all six regulated facilities were included in the Haddon Jackson Associates program. For the year 2004, Sir Adam Beck I and DeCew Falls I and II were included in the Haddon Jackson Associates' benchmarking program, and for 2003, Sir Adam Beck II and Saunders, were included in the Haddon Jackson Associates' benchmarking program.

The results of the Haddon Jackson Associates' OM&A unit energy cost benchmarking are summarized in the chart below.

Chart 5

Hydroelectric Benchmarking Results

Name of Station/Grouping	Value In 2003 & Quartile	Value In 2004 & Quartile	Value In 2005 & Quartile	Value In 2006 & Quartile	Comparison Details/Note for 2006	Source and Peer Group
DeCew Falls I	n/a	n/a	26.1 (Q3)	47.7 (Q4)	Q4 from 29.6 to 78.4	Haddon Jackson Associates (HJA): 22 micro plants (< 30 MW)
DeCew Falls II	n/a	3 (Q2)	4.8 (Q3)	7.7 (Q3)	Q3 from 4.8 to 7.7	HJA: 41 medium plants (150 to 400 MW)
SAB I	n/a	4.2 (Q4)	5.8 (Q4)	5.3 (Q4)	Q4 from 4.2 to 6.1	HJA: 13 med-large plants (400 to 700 MW)
SAB II	2.4 (Q2)	n/a	1.7 (Q1)	1.6 (Q1)	Q1 from 0.6 to 1.7	HJA: 25 large plants (700 MW or more)
SAB PGS	n/a	n/a	63.3 (Q4)	47.1 (Q4)	Q4 from 22.0 to 60.5	HJA: 15 PGS plants
Saunders	2.5 (Q3)	n/a	2.4 (Q3)	2.1 (Q3)	Q3 from 2.0 to 3.2	HJA: 25 large plants (700 MW or more)
5 OPG plants as above (Beck PGS excl'd)	n/a	n/a	2.6 (Q1)	2.6 (Q1)	Q1 from 0.6 to 3.3	HJA: 163 plants
All 6 OPG plants (including Beck PGS)	n/a	n/a	3.0 (Q1)	2.9 (Q1)	Q1 from 0.6 to 3.3	HJA: 187 plants

Note: The above unit energy costs are in U.S. dollars and include both hydro common cost allocations and corporate cost allocations. Official Bank of Canada average midpoint Canadian to U.S. exchange rates (2003 = .7135; 2004=.7683; 2005=.8253, 2006 = 0.8829)

For 2005, the above chart shows that Sir Adam Beck II, OPG's largest hydroelectric station, is in the first (best) quartile, Saunders in the third quartile (middle of quartile) and DeCew Falls No. I and II the third quartile and Sir Adam Beck 1 and Sir Adam Beck PGS are in the fourth quartile of their respective peer groups. Collectively, the regulated stations are in the first quartile due to the fact that Sir Adam Beck II (OPG's largest and lowest cost facility) has a dominating impact on the results and the peer group includes a larger set of plants.

For 2006, the above chart shows that Sir Adam Beck II, OPG's largest hydroelectric station, continued to be in the first (top) quartile; Saunders improved within the third quartile (just missing the second quartile); DeCew Falls I fell to the fourth quartile (mostly due to significantly lower energy production due to penstock problems and related outages); DeCew Falls No. II remained in the third quartile; and Sir Adam Beck 1 and Sir Adam Beck PGS remained in the fourth quartile of their respective peer groups. Collectively, the regulated stations remained in the top quartile excluding SAB PGS, and fell to the second quartile (just missing the first quartile) with SAB PGS included.

The OM&A unit energy cost benchmarking demonstrates that OPG's regulated hydroelectric facilities are cost competitive, especially if their very good reliability performance is taken into account. The OM&A costs for the regulated hydroelectric facilities must be considered in the context of their generally very good availability and reliability performance, as well as the age and condition of some of the plants. Good reliability is usually a function of how well the plants are maintained. This requires a prudent investments and on-going maintenance which drives funding/costs.

It is also important to note that the OM&A unit energy cost ranking for the regulated hydroelectric facilities is negatively impacted by the significant OM&A expenditures at the Sir Adam Beck stations and Saunders required to maintain and operate the Joint Works with NYPA (i.e., ice booms and ice breaking operations, International Control Dam, Iroquois Control Dam, etc., - see section 8.2 in this exhibit). These additional structures and activities are not typical of most of the generating stations that are benchmarked, and account for over

$5M per year in OM&A costs (or seven to nine percent of total annual OM&A costs for the regulated hydroelectric facilities).

Explanations for the ranking and specific cost issues for each station are provided below.

R.H. Saunders

In addition to the special Joint Works costs identified above, the relative OM&A cost ranking of R.H. Saunders is negatively impacted by the following inherent characteristics of the facility:

- There is a need for extensive instrumentation and ongoing monitoring of concrete "growth" associated with alkali-aggregate reaction at the station. Alkali-aggregate reaction is a chemical reaction within the concrete structure (between the cement and certain types of aggregate) resulting in concrete "growth". In the mid to late 1980's this growth led to major operational and structural problems. A major rehabilitation program was implemented in the 1990's to mitigate the effects of the concrete growth and restore operational reliability. The program included cutting "slots" between each of the 16 units using a special diamond wire technique, repairing the powerhouse structure, and replacing major mechanical and electrical equipment. It is difficult to estimate when the concrete growth will stop, thus the growth, and re-established joints between the units, are being monitored. If it is determined in the future that the joints are "closing up" and lead to operational problems, re-slotting of the units will be required. Based on monitoring to date, re-slotting will likely not be required in the next five to ten years.

- R.H. Saunders has on-site operators for both operations and site security. Because Saunders is situated on the St. Lawrence River, which is transected by an international border with the United States, site presence is necessary to ensure security and public safety. The St. Lawrence - Franklin D. Roosevelt plant on the U.S. side (owned by NYPA) is connected to the Saunders plant. Local presence is also required to carry out our operational and maintenance commitments with respect to the Joint Works (including water control at the Iroquois Control Dam and annual installation and removal of ice booms), emergency preparedness, segregated mode of operation switching operations, and water transactions. Absent these unique circumstances, Saunders could be operated remotely from the control centre at Chenaux Generating Station (approximately 200 km away).

Sir Adam Beck I

The OM&A costs of Sir Adam Beck I are higher compared to its peer group due to the following factors:

- The station is over 85 years old and the "power train" equipment is reaching end of life and needs rehabilitation or replacement (condition varies with each unit).
- Three of the ten units are 25 cycle units, with only two of these units in service. The 25 cycle units generally require more maintenance than most 60 cycle units due to their very poor condition. In addition, there is a cost to maintain the additional frequency changer equipment which converts energy from 25 to 60 cycle and vice-versa, and the Niagara Transformer Station which is specifically required for the 25 cycle system.

The two in-service 25 cycle units will be taken out of service by April 2009. This project is discussed in Ex. D1-T1-S1. One or more of these units may be converted to conventional 60 cycle power. The business case for the first unit conversion from 25 to 60 cycle was approved by the Board of Directors in May 2007 and the project has started. The unit rehabilitation/conversions, and shutdown of Niagara Transformer Station and frequency changer, are expected to reduce OM&A costs at Sir Adam Beck I by the end of 2011. As such, its benchmarking performance is expected to improve thereafter.

Sir Adam Beck II

Sir Adam Beck II is expected to remain in the top quartile of its peer group. All 16 units at the station were upgraded with new more efficient equipment installed from 1996 to 2005.

Sir Adam Beck Pump Generating Station

Sir Adam Beck PGS costs are in the fourth quartile primarily due to the uniqueness of the station relative to other pumped storage stations. This plant is benchmarked with other pumped storage stations that are of much more modern and less complex in design, which have much larger units (economies of scale), and which operate differently than Sir Adam Beck PGS. In addition to its role in pumping water for use during peak periods, Sir Adam Beck PGS is used to control the cross over elevation of the Sir Adam Beck canals, to assist in automatic generation control, as well as to provide flexibility and optimization of operations at the Sir Adam Beck complex. Due to this unique role, the units are subjected to a high frequency of control actions leading to more wear and tear, and more problems and maintenance. These factors lead to significantly higher OM&A unit energy costs than a typical pump generating station, as well as below average availability and reliability.

DeCew Falls

The DeCew Falls I OM&A unit energy costs are in the third and fourth quartile due to the very old age (108 years) and condition of the plant, which results in high maintenance costs. A major overhaul of some of the units is planned to extend the life of the facility, which on completion can be expected to stabilize on-going maintenance costs. This facility is also being assessed to determine whether it will be more economic to replace it with a new unit. A detailed plant condition assessment and life cycle plan is underway to determine the preferred option for this station.

With regard to DeCew Falls II, OM&A costs increased from 2004 to 2006 due to the major overhaul work performed on one of the units in 2005/2006. This caused the ranking to decline from second quartile in 2004 to third quartile in 2005 and 2006. The overhaul program for DeCew Falls II was completed in mid-2007, thus major overhaul costs will no longer be incurred. This should improve the relative ranking of this station in 2008.

7.3 Safety (Accident Severity Rate)

OPG and Hydroelectric spend a significant amount of time and effort through training and awareness to ensure the safety of its employees. Safety performance is benchmarked through the CEA. The benchmarking data supplied by CEA is an aggregate of electrical generation utilities in Canada. Most of these utilities have a mix of various generation technologies and provide transmission service. The top quartile accident severity rate for these utilities from 2003 to 2005 was 4.6 days lost per 200,000 hours. From 2004 to 2007, regulated hydroelectric stations have not had a lost time accident. The accident severity rate for the regulated hydroelectric facilities has been zero for this period (i.e., top quartile performance).

8.0 KEY HYDROELECTRIC REGULATIONS, AGREEMENTS AND PROGRAMS

OPG's regulated hydroelectric facilities are subject to international treaties between Canada and the United States, federal and provincial legislation and regulatory requirements, as well as several contractual arrangements with third parties. Collectively these result in additional costs and program needs with respect to the operation and management of the regulated facilities.

This section provides an overview of:

- Regulations, treaties and agreements with regard to water rights for the regulated hydroelectric facilities.
- The Niagara MOU and the St. Lawrence MOU with NYPA.
- Dam and public safety governance and programs.

A summary of the broad regulatory framework applicable to OPG's regulated facilities, including the environmental requirements for the regulated hydroelectric facilities is provided at Ex. A1-T6-S1.

8.1 Water Rights

Regulation of Water Rights

Hydroelectric generation requires ongoing access to an adequate water supply. The physical availability of water is affected by numerous factors, including variations in precipitation, sublimation, and evaporation. Rights to and restrictions on the use of water are determined primarily by international treaties between Canada and the United States and certain orders and approvals thereunder, together with the application of inter-provincial agreements, federal and provincial legislation, common law as it pertains to real property and riparian rights, as well as the terms and conditions of certain leases and permits with and from the Government of Canada and the Province of Ontario.

International Rivers

OPG's regulated hydroelectric generating stations are directly or indirectly supplied by two major international waterway systems, Lake Erie/Niagara River in the case of the Niagara Plant Group and Lake Ontario/St. Lawrence River in respect of Saunders. As such, the Niagara stations are operated pursuant to two treaties between Canada and the United States and Saunders is subject to one.

The Boundary Waters Treaty of 1909 between Canada and the United States governs all boundary waters between Canada and the United States, including the Lake Erie/Niagara River and Lake Ontario/St. Lawrence River. The Niagara Diversion Treaty of 1950 between Canada and the United States, among other things, provides for the termination of certain sections of the Boundary Waters Treaty of 1909, provides for the construction of the International Niagara Control Works, determines the priority of use for the waters of the Niagara River and Welland Canal, and sets minimum flow requirements over Niagara Falls. Each of the Boundary Waters Treaty of 1909 and the Niagara Diversion Treaty of 1950 continue in perpetuity, but are terminable by either party on 12 months prior written notice. Given the significant importance of these treaties, OPG does not expect Canada or the United States to exercise their termination rights in the foreseeable future.

The Boundary Waters Treaty of 1909 and the Niagara Diversion Treaty of 1950 grant Canada and the United States equal rights to use waters available for power generation. The Niagara Diversion Treaty of 1950 recognizes certain diversion waters (5,000 cubic feet per second or approximately 142 cubic metres per second) which are diverted by Canada into the Great Lakes Basin as not being included in the allotment of waters under the provisions of the treaty, and which is therefore used solely by Canada at OPG's Niagara hydroelectric facilities. This water is diverted from the James Bay watershed by the Ogoki and Long Lac Diversions in northern Ontario, to the Niagara system via the upper Great Lakes.

Through a series of agreements between the Government of Canada and the Province of Ontario, certain Government of Canada statutes, and certain Province of Ontario statutes, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance and operation of generating facilities under the Boundary Waters Treaty of 1909 and the Niagara Diversion Treaty of 1950.

OPG and NYPA have entered into an agreement ("Operations MOU") which provides for an opportunity for the parties to maximize energy production from the total water available for generation under the relevant international treaties. The Operations MOU permits, under certain circumstances, an entity the opportunity to extract at such entity's generating facility(ies) (the "Generating Entity") the potential energy from a portion of the other entity's share of the water available for power generation. In return, the Generating Entity provides the revenues resulting from such transaction, as per the terms of the MOU and minus an accommodation charge, to the other entity.

The implementation of, and the operations governed by, the Boundary Waters Treaty of 1909 and the Niagara Diversion Treaty of 1950, are monitored and regulated by certain international entities. The Boundary Waters Treaty of 1909 created an international commission called the International Joint Commission ("IJC") to help prevent and resolve disputes over the use of boundary waters between Canada and the United States. The IJC was asked to help implement the Niagara Diversion Treaty of 1950 by overseeing the design, construction and operation of the International Niagara Control Works. The IJC monitors all activities that may impact the treaties to ensure that the interests of both countries are protected.

The IJC established the International Niagara Board of Control in 1953. The International Niagara Board of Control provides advice on matters related to the IJC's responsibilities for water levels and flows in the Niagara River. The International Niagara Board of Control's main duties are to oversee water level regulation in the Chippawa-Grass Island Pool and the installation of the Lake Erie-Niagara River ice boom. The International Niagara Board of Control also collaborates with the International Niagara Committee, a body created by the

Niagara Diversion Treaty of 1950 to determine the amount of water available for Niagara Falls and power generation.

The IJC established the International St. Lawrence River Board of Control in 1952. The International St. Lawrence River Board of Control's main duty is to ensure that outflows from Lake Ontario meet the requirements of the relevant IJC order, which includes dependable flow for hydropower, adequate navigation depths and protection for shoreline and other interests downstream in the Province of Quebec. The International St. Lawrence River Board of Control also develops regulation plans and conducts special studies as requested by the IJC. Outflows are set by the International St. Lawrence River Board of Control under such regulation plan.

Niagara Parks Commission – Niagara Plants

OPG's tenure for the immediate area surrounding the Beck generating stations, as well as the area surrounding the Beck generating stations' intakes upstream of Niagara Falls, is by way of a lease agreement with The Niagara Parks Commission pursuant to the *Niagara Parks Act* (Ontario).

The *Niagara Parks Act* (Ontario) also grants to Niagara Parks Commission the authority to grant certain rights to use the waters of the Niagara River for purposes of power generation. The Niagara Parks Commission granted franchise agreements to three entities in the late 1800's and the first decade of the 1900's. OPG is a successor to two of the three franchise agreements. Through a series of agreements with the Niagara Parks Commission, and an agreement with FortisOntario Inc., the successor to the third franchise agreement, OPG has the right to use all rights which were granted under the *Niagara Parks Act* (Ontario).

One of the agreements mentioned in the preceding paragraph is commonly referred to as the Niagara Exchange Agreement and is an agreement between OPG and FortisOntario Inc. ("Fortis"). Pursuant to a franchise agreement granted to a predecessor of Fortis for a generating station commonly known as the Rankine Generating Station, Fortis may withdraw a certain amount of water from the Niagara River for purposes of generating at the Rankine

Generating Station. Pursuant to an irrevocable agreement between OPG and Fortis, Fortis has assigned its right to use such waters from the Niagara River to OPG. In exchange, OPG provides a certain amount of energy output continuously until 2009.

The DeCew Falls stations use water that is transported along the Welland Canal from Lake Erie by the St. Lawrence Seaway Management Corporation under an agreement between OPG and the St. Lawrence Seaway Management Corporation that expires on June 30, 2008. OPG has provided notice to the St. Lawrence Seaway Management Corporation of its intent to renew the term of the agreement for a further period of 30 years, as per the terms of the agreement. Discussions have been initiated to reach mutual agreement as to the fees that will be payable during the renewal term.

8.2 Joint Works Agreements with New York Power Authority

As previously discussed, OPG has two agreements with the NYPA with respect to cost sharing and the management of joint works at each of the Niagara River and St. Lawrence River hydroelectric generation developments (collectively the "Joint Works Agreements"). The Joint Works Agreements provide the framework for defining, planning, executing and sharing costs for Joint Works (as defined in the Joint Works Agreements) in association with their respective generating facilities on each of the Niagara River and the St. Lawrence River.

Management and administration of the Joint Works Agreements is carried out by means of the following processes:

- High level, joint meetings of the Niagara and St. Lawrence Joint Works Committees between NYPA and OPG are held every fall to discuss strategic initiatives and operational concerns, to identify areas of risk and to share experience regarding "best practices" for the shared maintenance, operations and project work on the Niagara River and St Lawrence River systems. This meeting is attended by executives from both NYPA and OPG, along with their support staff.

- The overall management of the respective Joint Works Agreements has been delegated to the Services Manager for the Niagara Plant Group and the Saunders Production Manager and Site Controller for the Ottawa/St. Lawrence Plant Groups.
- Quarterly meetings of local working committees for each of the Memoranda are held with technical and finance staff from both NYPA and OPG in order to:
    - Determine if new work, or revised existing work meets the criteria for joint works as per the Memoranda of Understanding.
    - Conduct a detailed review of the five-year plan to classify, prioritize and break out work packages that qualify for joint works for both NYPA and OPG. Cost estimates and scope of work packages are reviewed and appropriate changes are made where necessary, with the agreement of both parties.
    - Review year-to-date variances from budget on a work-package-by-work-package basis to help OPG and NYPA understand and identify variances that may be permanent in nature and therefore require funding adjustments to other areas of the plan. Every effort is made to defer other recurring non-production maintenance activities when a permanent, unfavourable variance is confirmed. However, there will be occasions when deferral is not an option so the variance would be approved on an exception basis with the expectation that the following year's expenditures are returned to approved levels.
    - Review year-end projections on a work-package-by-work-package basis to feed into both NYPA's and OPG's overall forecasts and to prioritize work. This process also provides the opportunity to manage other, current year, joint works costs so that the overall impact on the whole program is minimal.

The Joint Works Agreements at Niagara and R.H. Saunders are administered separately from each other.

8.3 Dam Safety and Public Safety

OPG's Hydroelectric Business Unit operates a total of 238 dams in connection with its 64 hydroelectric plants. Of these, twenty-seven dams, including several special hydraulic structures, are associated with stations in the Niagara Plant Group and three dams are associated with the R.H. Saunders Generating Station. Dam safety legislation does not currently exist in the Province of Ontario, although the Ministry of Natural Resources is currently considering introducing dam safety legislation. While the regulatory regime concerning dam safety and public safety is currently in a state of development, OPG has well-established programs in these areas that are in many respects seen as a model for emerging standards and regulatory requirements. As such, this section will start with an overview of OPG's dam safety program and will then discuss the existing and emerging regulatory requirements in these areas.

<u>OPG's Dam Safety and Waterways Public Safety Programs</u>

OPG's Dam Safety Policy, approved by the Board of Directors directs that dams be designed, constructed, operated and maintained in a manner that meets all regulatory requirements or, in the absence of regulations, the safety guidelines published by the Canadian Dam Association or other industry best practice.

The former Ontario Hydro established a dam safety program in 1985 to ensure the safe and reliable operation of its dams and related facilities. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program and is seen to be an industry leader in many aspects of the program. External reviews conducted by the Association of State Dam Safety officials in 1997 have concluded that OPG's program is effective, well-managed and contains all necessary technical elements to minimize the risks to the public, property and the environment associated with the dams and their operations.

OPG's dam safety program includes the preparation of annual project execution plans by each plant group, including the Niagara Plant Group and the Ottawa/St. Lawrence Plant Group with which Saunders is affiliated. These plans ensure that the plant groups are accountable for their respective dam safety programs, and associated activities:

- Inspection, monitoring and surveillance of dams and hydraulic structures.
- Routine testing of flow control equipment.
- Emergency preparedness plan updates, drills and exercises.

- Staff training on all aspects of emergency preparedness, operations, maintenance and surveillance.
- Periodic reviews to ensure compliance with current standards and practices.
- Technical audits and independent expert reviews.
- Rehabilitation projects (maintenance and dam safety improvements where necessary).
- Development and maintenance of governing documents, including policies, standards, guidelines and procedures.
- Incident reporting and follow up on lesson's learned.
- Communications with regulatory agencies regarding emergency preparedness and compliance issues.
- Research and development for the purposes of continuous improvement of the program.

In regards to the periodic reviews, these involve the engagement of independent consulting engineers and are performed at five to ten year intervals, depending on the consequence rating of the structures. For dams and hydraulic structures at the regulated hydroelectric facilities, the periodic reviews are conducted on five year intervals. There are also a number of on-going studies supporting the periodic reviews and assessment of integrity. These studies are incorporated in OPG's business plans.

Over the past three years, OPG's Hydroelectric Business Unit has spent great effort to develop a number of technical documents concerning public safety around dams, as well as materials to educate the public and raise awareness of the hazards associated with the operation of our dams and hydroelectric facilities. This work was undertaken in advance of government requirements/guidelines or industry standards in this emerging area to ensure continued due diligence in public safety. Both the Ministry of Natural Resources and Canadian Dam Association, are presently in the process of developing guidelines for public safety around dams. OPG is participating in both of these initiatives.

OPG has incorporated the Waterways Public Safety Program into its managed systems with the following elements:

- Development of guidance documentation/standards.

- Delegation of accountabilities.
- Operating procedures.
- Physical control measures (installation, maintenance, inspection and testing).
- Employee training.
- Incident reporting.
- Public education and awareness.
- Program reporting.
- Oversight.

In the area of public safety around dams, OPG has worked diligently to entrench a "Stay Clear - Stay Safe" message as part of the public education program. OPG actively engages other agencies such as the Ministry of Natural Resources ("MNR"), Ontario Provincial Police, St. John's Ambulance, Life Saving Society, the Ontario Waterpower Association, and numerous other stakeholders in water safety education to partner in delivering the message to the public.

<u>Regulatory Regimes for Dam Safety and Waterways Public Safety</u>

In Canada, dams come under the jurisdiction of the provinces, with the exception of dams situated in boundary waters and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province of Ontario.

<u>Federal / International Jurisdiction</u>

The IJC has an oversight role in regards to dams and associated works on boundary waters, including the St. Lawrence and Niagara Rivers. In 1998, the IJC published a review entitled "Unsafe Dams?" which assessed the state of governance for structures located on boundary waters in both Canada and the United States. Their conclusion was that though owners such as OPG were exercising appropriate levels of due diligence in regards to dam safety, additional oversight in the form of provincial dam safety regulations was required for dams in Canada. In 2006, the IJC published an update of this report, which again concluded that owners were fulfilling their due diligence requirements, but that the Province of Ontario needed to act on the recommendation for legislation to govern the safety of dams.

Province of Ontario – Dam Safety

The Province of Ontario currently governs dams under the *Lakes and Rivers Improvement Act*, administered by the MNR*.* Sections 14 and 16 of the *Lakes and Rivers Improvement Act* require MNR approval for activities such as the construction, alteration, improvement, or repair of dams. The existing MNR Criteria for Approval under the *Lakes and Rivers Improvement Act* were developed in 1977 and are currently regarded as a guidance document relating to provincial standards for such aspects of dam safety as the classification of dams, the selection of the inflow design flood and structural stability criteria. The MNR began a process for developing an actual regulation governing dam safety in 1999. The regulation is expected to be enacted under the *Lakes and Rivers Improvement Act*. The initial release from the MNR was in the form of a draft-for-comment Ontario Dam Safety Guidelines in 1999. The MNR has since updated the draft in 2004, which included a posting on the Environmental Registry, entitled Technical Guidelines and Standards for Dam Safety and Public Safety Around Dams. Since posting the draft in 2004, the MNR has engaged industry in a consultative process to further refine the provincial standards. OPG is an active member of the MNR's Advisory Panel and Working Groups which form part of the consultation. The Ministry's consultative process is on-going with no definitive date for conclusion.

Based on OPG's preliminary review of the most recent version of the draft regulation from MNR, OPG does not anticipate that major capital improvements will be required for the dams or hydraulic structures associated with regulated hydroelectric facilities. However, the draft regulation would impact the facilities by imposing an annual administrative registration fee for dams. As well, the regulation will likely require additional engineering resources to prepare documentation required to support applications for approval under the *Lakes and Rivers Improvement Act* covering maintenance works on the dams. The MNR has not provided definitive direction as of yet in regards to the fee structure, or the exact requirements for approvals under the *Lakes and Rivers Improvement Act*.

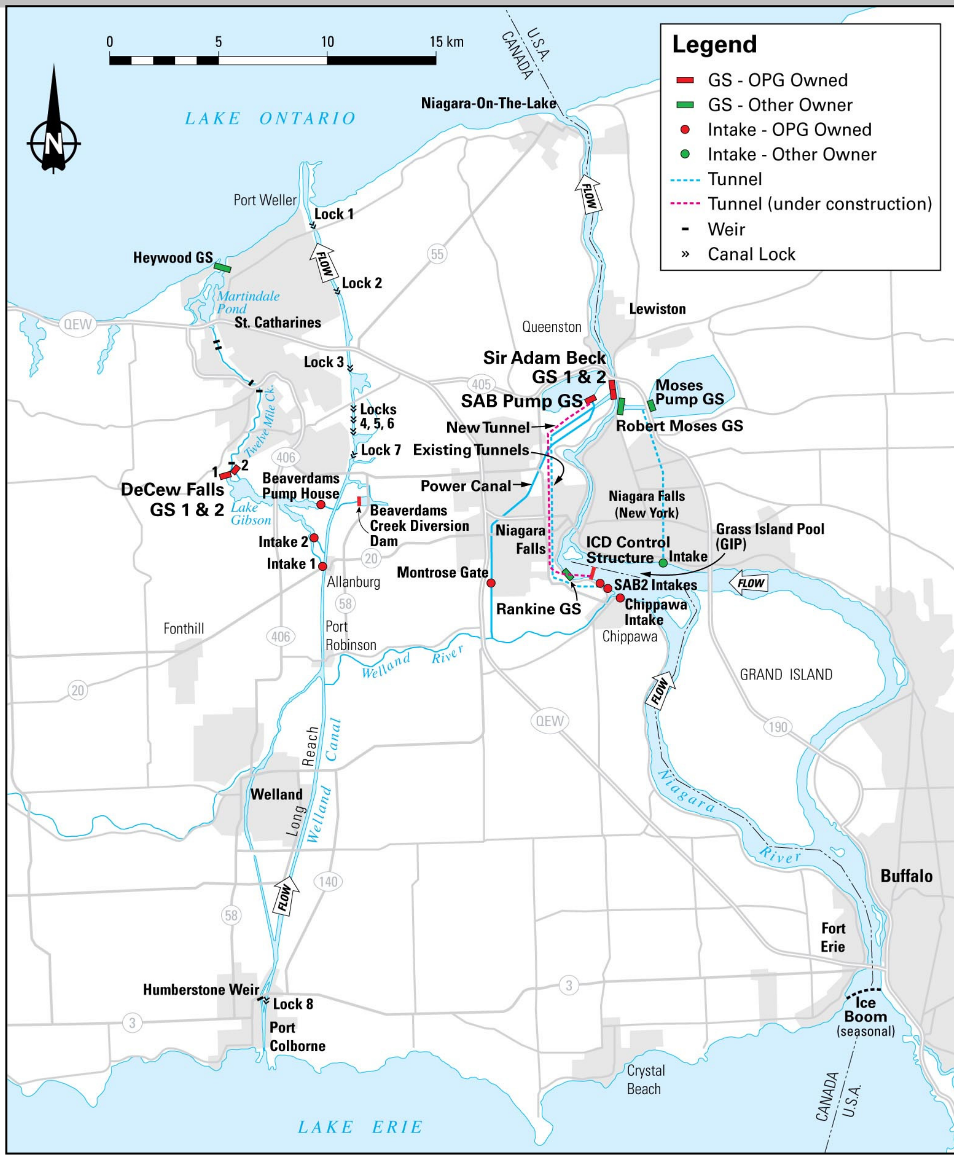
Pursuant to OPG's dam safety program, dam safety periodic reviews were completed for dams associated with the Sir Adam Beck facilities, and the International Niagara Control Works, in 2007, and for the DeCew Falls Generating Station facilities in 2003. Periodic reviews were completed for dams associated with the R.H. Saunders Generating Station in 2005. While there were recommendations for work to be carried out at each of these facilities to maintain their safe operation, there were no specific recommendations which would be likely to change as a result of the proposed new provincial dam safety regulation. Costs associated with the recommended maintenance and safety improvements have been incorporated in business plans.

Province of Ontario - Waterways Public Safety

Currently there is no provincial or federal regulation with respect to public safety around dams which would address public safety from the perspective of changes in operating water levels, discharges from the hydropower or dam facilities, as well as other waterways based hazards posed by the facilities. In this regard, OPG has exercised due diligence in undertaking a major program to develop guidelines, standards and materials to improve the public's awareness in the interest of public safety associated with dams and hydropower station operations. The Province of Ontario has indicated that it intends to incorporate a waterways public safety program as part of their proposed dam safety regulations. OPG has participated in the development of the provincial guidelines which have been based primarily on OPG's practices.

LIST OF ATTACHMENTS

Niagara Plant Group




Sir Adam Beck GS 2& 1

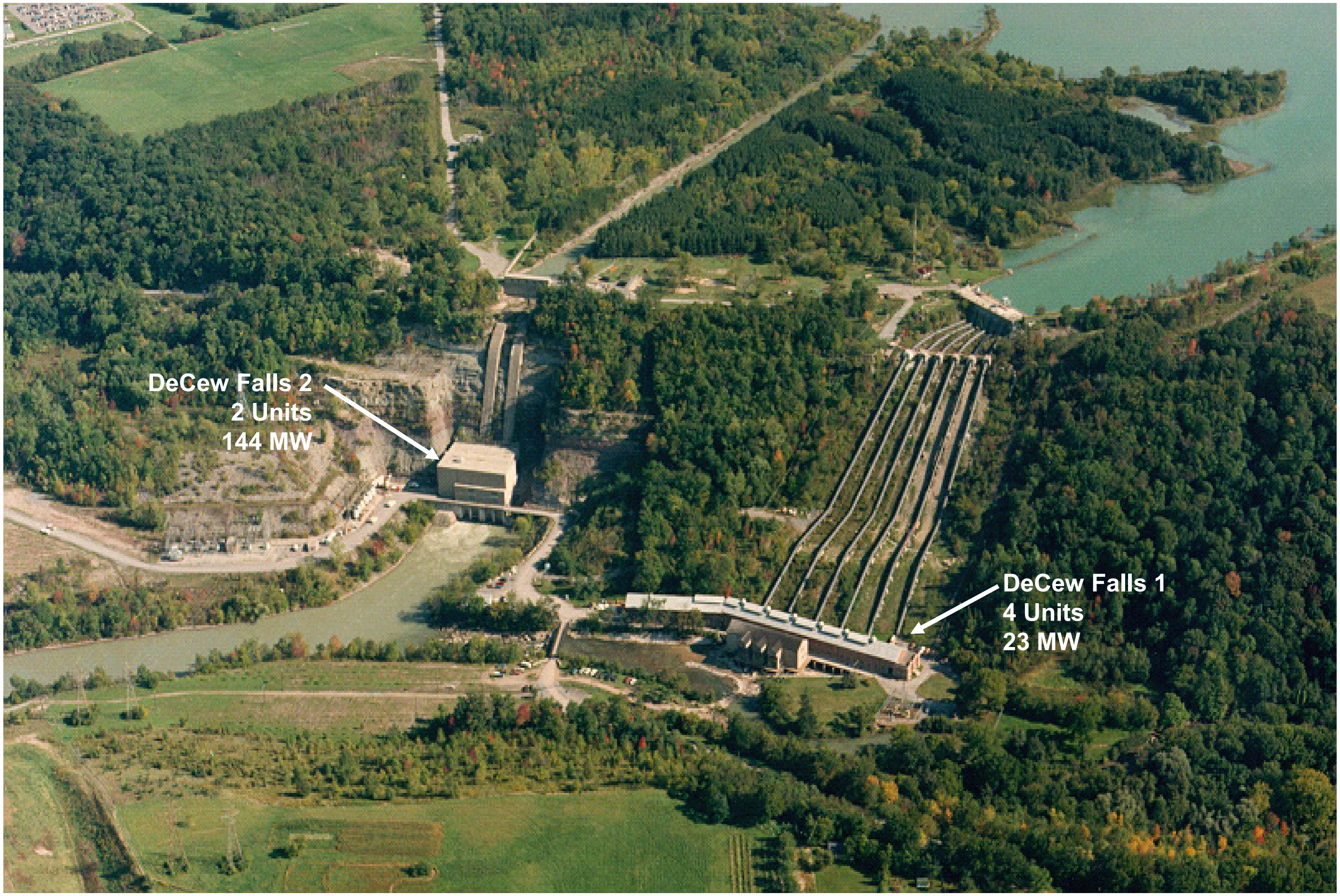

DeCew Falls GS 1 & 2

ONTARIOPOWER GENERATION

Niagara – Sir Adam Beck (SAB) Complex

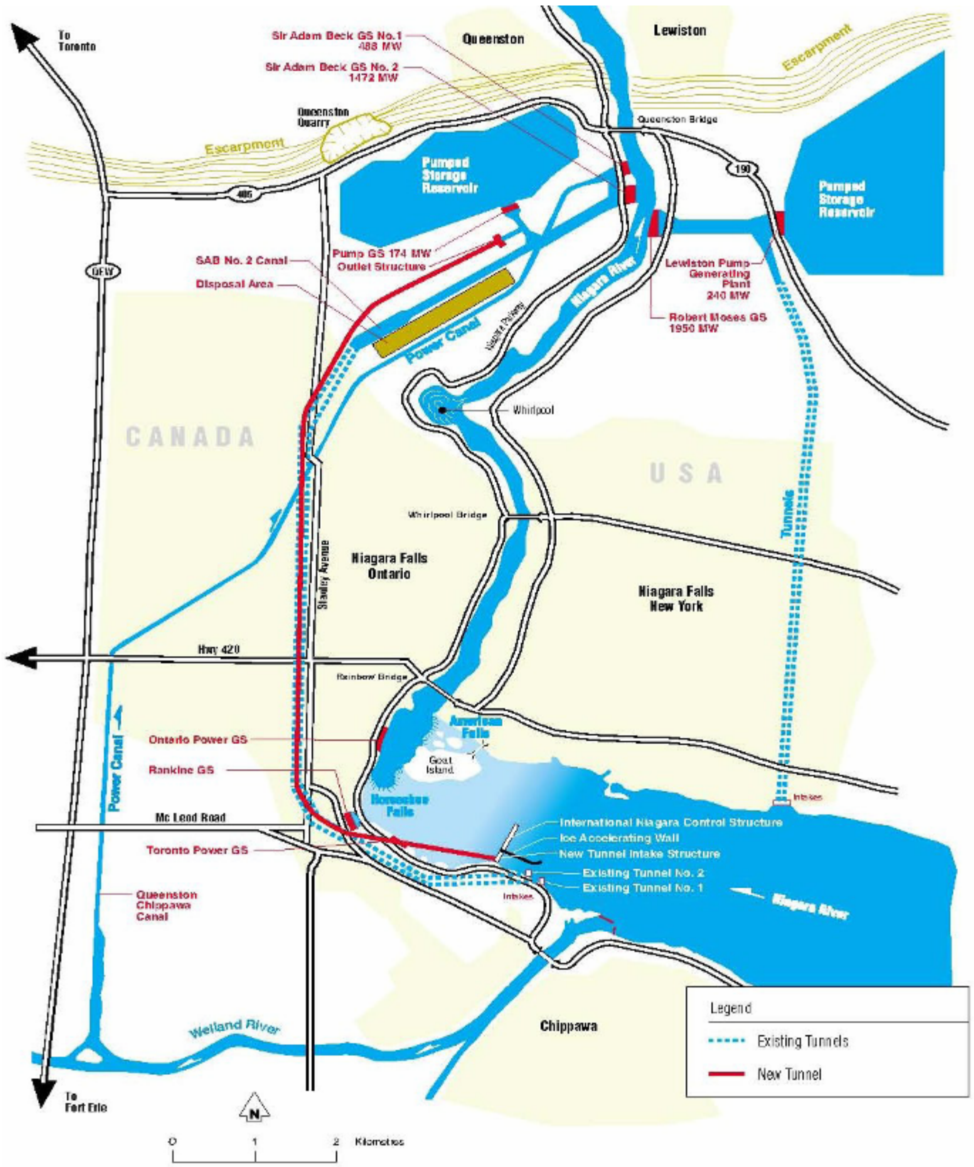
ONTARIOPOWER
GENERATION

Niagara – DeCew Falls 1 & 2



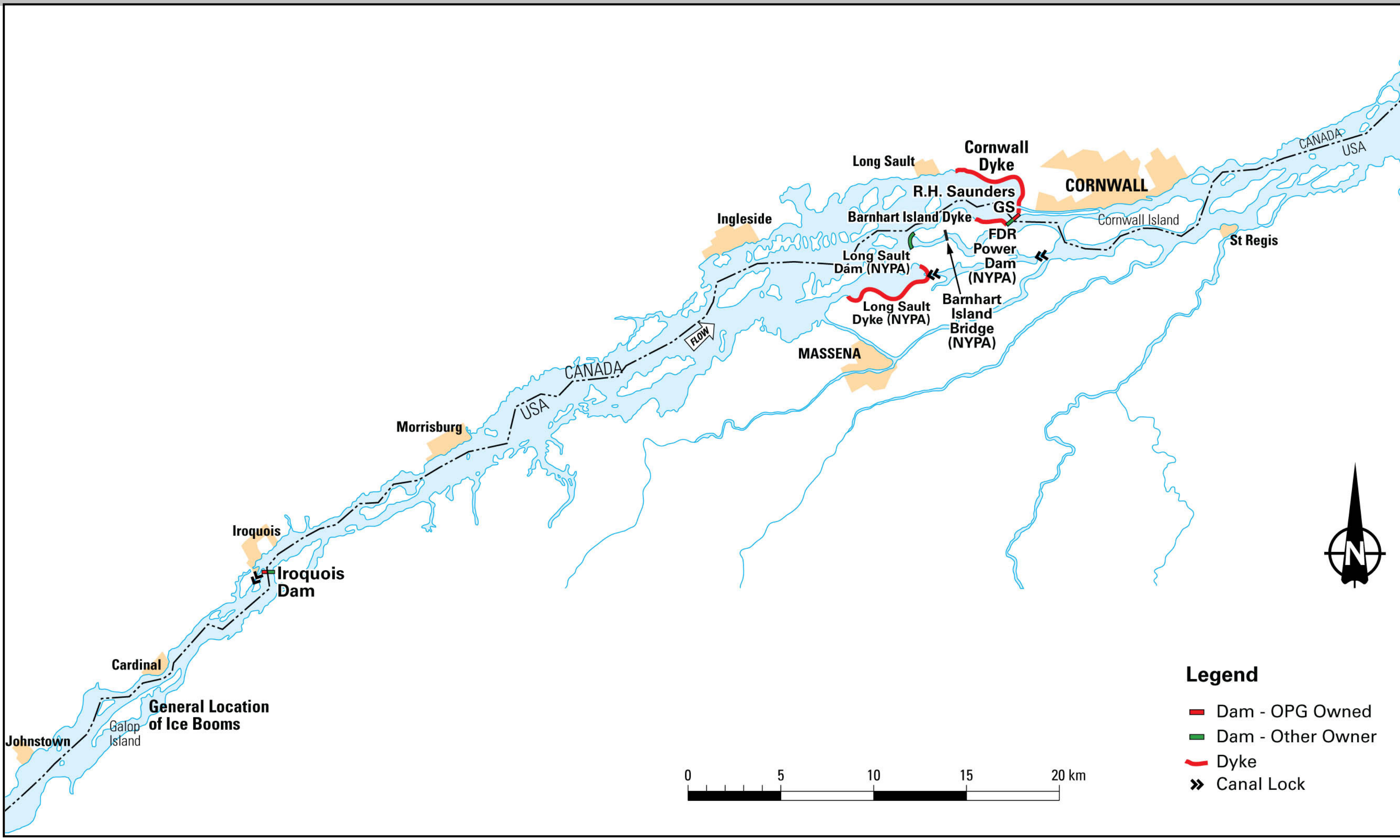
ONTARIOPOWER GENERATION

Niagara Tunnel - Overview



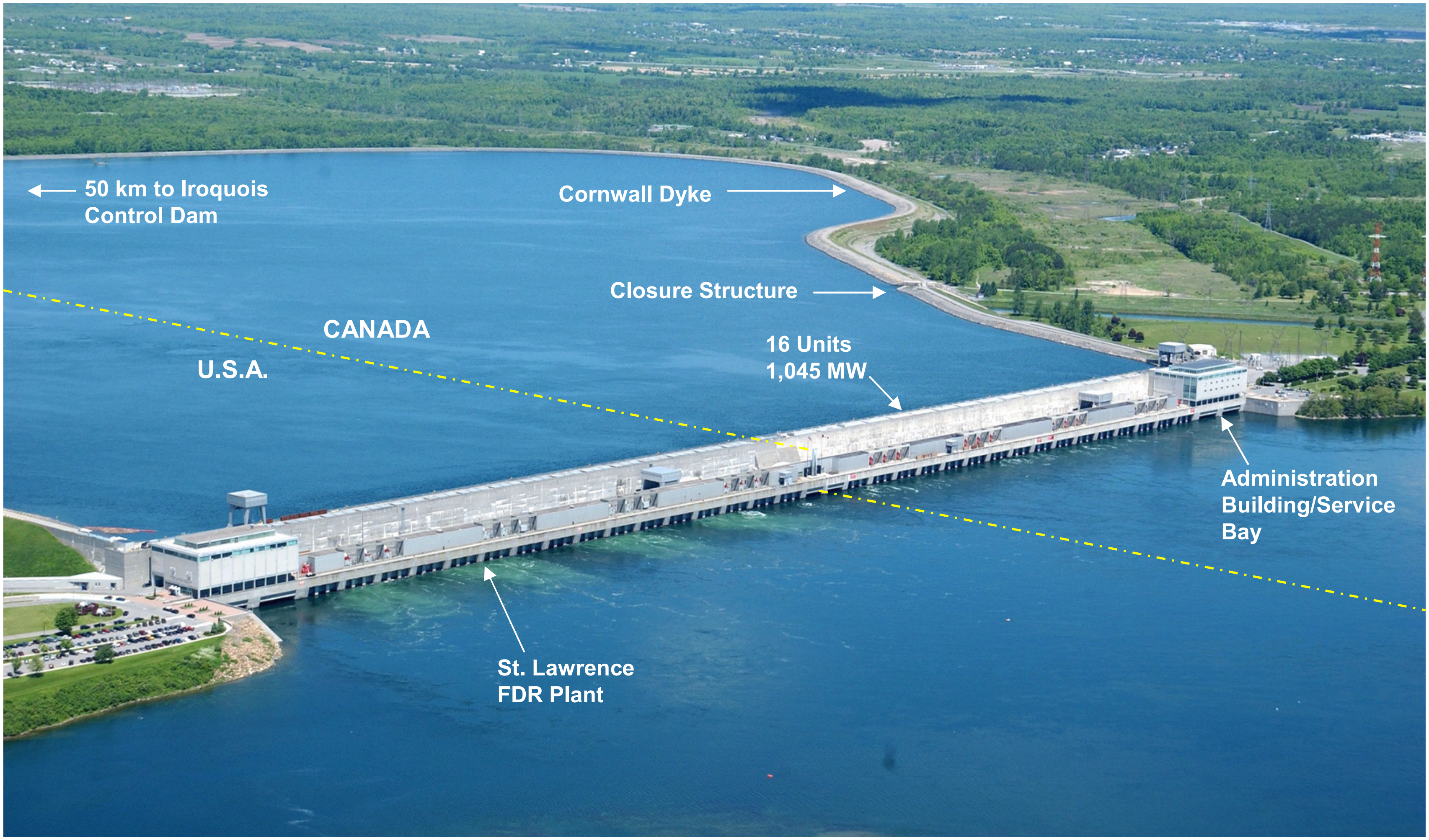
ONTARIO POWER GENERATION

St.Lawrence River



ONTARIOPOWER GENERATION

Saunders GS



ONTARIO POWER GENERATION

OVERVIEW OF NUCLEAR FACILITIES

1.0 PURPOSE

The purpose of this evidence is to provide a description of the nuclear facilities, an overview of the nuclear mandate, objectives, organization, management framework, as well as key performance targets and benchmarking information.

2.0 OPG'S NUCLEAR GENERATING FACILITIES

OPG nuclear facilities consist of Pickering A Generating Station (Pickering A), Pickering B Generating Station (Pickering B), and Darlington Generating Station (Darlington) (collectively, the Nuclear Generating Stations). All of the nuclear generating stations are CANDU reactors, which are a pressurized-heavy-water, natural-uranium technology developed in Canada. CANDU is an acronym for Canada Deuterium Uranium. CANDU reactors are unique in their use of natural uranium, deuterium oxide (heavy water) as a moderator/coolant, on-line refueling capability and two shut down safety systems. These plants serve as base load resources since they have been designed to operate at full power. A photograph of Darlington is presented in Attachment A and a photograph of Pickering A and B is presented in Attachment B. Chart 1 below provides some basic information about the nuclear generating stations.

Chart 1

Nuclear Generating Stations Basic Information

	Pickering A	Pickering B	Darlington
In-service Dates	1971 to 1973	1983 to 1986	1989 to 1992
Net In-service Capacity	1,030 MW	2,064 MW	3,512 MW
Number of Units in service & size in MW's	2 x 540	4 x 540	4 x 934

While OPG's ten nuclear units are all CANDU reactors, they reflect three generations of design philosophy and technology with: Pickering A, Pickering B, and Darlington built in the 1960's, 1970's, and 1980's respectively. This results in significant variations among the three nuclear stations including technology and overall design. Darlington has a greater number of components located outside containment and are therefore more physically accessible for on-line maintenance versus Pickering A or Pickering B. Darlington units are larger generating capacity, but have fewer major components. More extensive use of digital equipment controls was made at Darlington versus a greater reliance on analog control technology at Pickering. This lack of standardization due to "generation of design" limits OPG's ability to integrate operations and apply uniform approaches across the stations. These differences also impact on the extent and nature of operations and maintenance activity at each station. In addition, the differences impact the ability to fully leverage fleet standardization potential and optimize/streamline infrastructure. Some examples of this are presented below - additional details are in Ex. F2-T2-S1:

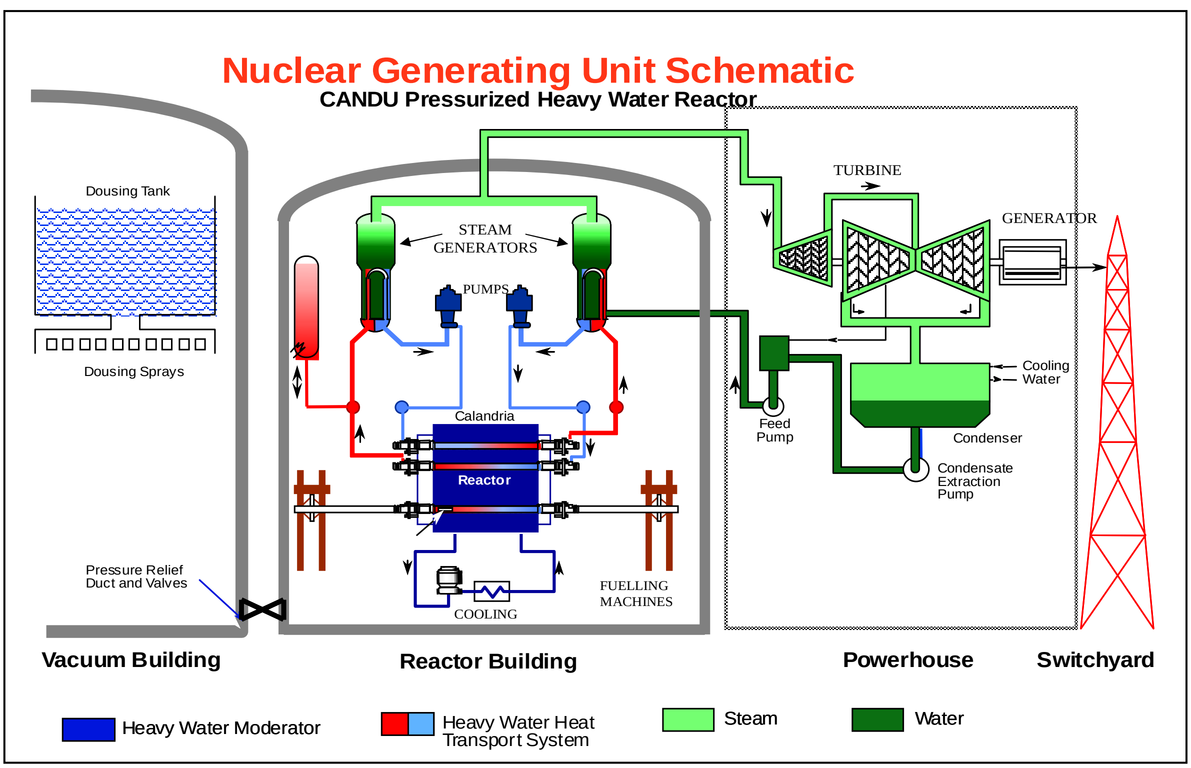
- Operator Requirements: Canadian Nuclear Safety Commission licenses are site specific, which means they are not readily transferable between plants. This affects both operating and outage flexibility with respect to demand for operators.
- Licensing Costs: Each station requires a fully separate licensing process, with associated costs.
- Training Costs: With the exception of basic skills training, the majority of technical training is not transferable between stations. The difference between stations necessitates station-specific staff training uses separate simulators to train control room operators.
- Other Costs: Differences between stations also mandate the need for station-specific technical procedures, and maintaining extensive inventories associated with station-specific parts.

The nature of the technology and the nuclear regulatory environment impacts operations and costs in other ways. While more detailed information is provided in Ex. F2-T2-S1, some of the more significant items are:

- <u>Aging Technology</u>: OPG's nuclear stations contain the first large CANDU units built, the result being that many of the technological issues OPG faces are being addressed for the first time in the nuclear industry.

- Evolving/Escalating Regulatory Standards: To conform to changing regulatory standards often stations must be retrofitted which involves significant cost (e.g., the second, enhanced shutdown system retrofitted at Pickering A). These requirements are largely mandated by the Canadian Nuclear Safety Commission as described in Ex. A1-T6-S1 with oversight through on-site Canadian Nuclear Safety Commission staff. Frequently changes to standards occur as a result of incidents or experience elsewhere in the nuclear industry, and this is a constant ongoing process. Additionally, recent world events have significantly changed security requirements.

- Advancements in Technology: Research and development activities lead to advancements that improve the operability and safety of the stations, with various impacts on cost. For example, specialized diagnostic tools and improved inspection capabilities make it possible to inspect an increasing range of components to a higher degree of precision. These new techniques are essential to the long term health of the units, but can increase the cost of OM&A.



3.0 NUCLEAR GOVERNANCE FRAMEWORK

The Chief Nuclear Officer Charter contains all the key aspects of the governance framework embodied in nuclear facility operations. OPG's Nuclear Safety Policy is derived from this Charter, and defines the principles, objectives, and responsibilities governing the safe operation of OPG's nuclear facilities. It requires that the Board of Directors regularly review nuclear safety performance. It also requires the Chief Nuclear Officer establish a Nuclear Oversight Committee and enlist the World Association of Nuclear Operators to provide independent advice regarding OPG nuclear activities that may impact on nuclear safety.

In addition, OPG is subject to various federal and provincial legislation and regulations including:

<u>Federal</u>

- Canadian Nuclear Safety Commission – All nuclear construction requirements, equipment, safety systems, operating limits, licences, emergency response, decommissioning and waste management are subject to Canadian Nuclear Safety Commission approval. The requirement to meet nuclear safety regulations and standards is imposed by the *Nuclear Safety and Control Act*.
- Environmental legislation includes the *Canadian Environmental Protection Act*, the *Fisheries Act*, and the *Canadian Environmental Assessment Act.*

<u>Provincial/Municipal</u>

- OPG is subject to provincial and municipal legislation including Ontario's *Environmental Protection Act* and the *Ontario Water Resources Act*.

4.0 NUCLEAR ORGANIZATION

The Nuclear business unit is comprised of Nuclear Operations, Nuclear Generation Development and Services, and the Nuclear Waste Management Division (per OPG's organizational chart shown in Ex. A1-T5-S1).

<u>Nuclear Operations</u>

Nuclear Operations under the direction and leadership of the Chief Nuclear Officer, is focused on the operation, maintenance, and performance of OPG's Pickering A, Pickering B and Darlington nuclear generating stations, along with oversight of various nuclear support services, which include:

- Engineering and Modifications
- Nuclear Programs and Training
- Nuclear Supply Chain
- Performance Improvement and Oversight

The description of the roles and responsibilities of the generating stations along with Nuclear Support Services is provided at Ex. F2-T2-S1.

Nuclear Generation Development and Services

The Senior Vice President Nuclear Generation Development and Services is responsible for the development work associated with consideration of life extension of Pickering B and Darlington, for undertaking the federal approvals process for new nuclear units in accordance with the shareholder direction, as well as for managing existing nuclear commercial services. This group also includes Inspection and Maintenance Services and Commercial Services (i.e., isotope sales as well as management of the Bruce Power lease), which are discussed in greater detail at Ex. G2-T1-S1.

Nuclear Waste Management Division

The Nuclear Waste Management Division is responsible for managing OPG's obligation for the ongoing long-term management of nuclear waste produced at the nuclear stations as well as the decommissioning of its nuclear generating stations after the end of their useful lives.

The Chief Nuclear Officer, the Senior Vice President Nuclear Generation and Development Services and the Senior Vice President of Nuclear Waste Management Division report to the Executive Vice President and Chief Operating Officer.

5.0 OPG NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

As they operate, OPG's nuclear reactors produce used nuclear fuel bundles, which are a form of high-level radioactive waste. Nuclear operations also give rise to other material that has come into close contact with the reactors, but which is less radioactive than used fuel. These materials include ion exchange resins and other structural material and reactor equipment, including pressure tubes (collectively, intermediate-level radioactive waste). Certain other material used in connection with station operation, but which is neither highly radioactive nor of an intermediate level of radioactivity, such as tools and protective clothing, are referred to as low-level radioactive waste. OPG is responsible for the ongoing long-term management of each of these categories of wastes. In addition, OPG will have to manage radioactive waste associated with the decommissioning of its nuclear generating stations (including the Bruce Generating Stations) after the end of their useful lives.

The liabilities of OPG's predecessor, Ontario Hydro, associated with nuclear waste management and decommissioning were transferred to OPG in April 1999. The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement between the Province of Ontario and OPG. The key provisions of the Ontario Nuclear Funds Agreement are:

- For OPG to establish two segregated funds, comprising the used fuel segregated fund (to fund future costs of nuclear used fuel waste management) and the decommissioning segregated fund (to fund the future cost of nuclear fixed asset removal and low and intermediate level waste management).
- For the Ontario Electricity Financial Corporation to be responsible for making a payment to the decommissioning segregated fund as specified within Ontario Nuclear Funds Agreement.
- For the Province to limit OPG's financial exposure in relation to the cost of used fuel management.
- For the Province to support financial guarantees to the Canadian Nuclear Safety Commission for OPG's nuclear waste management and decommissioning responsibilities by providing a provincial guarantee in return for an annual guarantee fee.

Details on nuclear waste management and decommissioning including the funding of nuclear liabilities are provided in Exhibit H.

6.0 NUCLEAR MANDATE AND OBJECTIVES

With respect to the nuclear facilities, the Memorandum of Agreement with the shareholder states:

> 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.
>
> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against 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.

Consistent with this mandate and OPG's corporate objectives, OPG Nuclear established the following objectives with the purpose of making Nuclear a more dependable, predictable, and cost effective operating entity:

- Safety: Continued focus on high performance.
- Human Performance: Continued improvements in human performance and leadership and continue to address demographics/knowledge transfer issues.
- Reliability: Maintain progress on improving material condition of the operating units and sustaining the improvements. Deliver improved outage performance with reduced duration.
- Value for Money: Improve cost structure by getting the right work and parts to the line to improve efficiency and lowering support costs.

The operating units are being maintained to ensure that OPG retains all options for extending the life of the units. OPG will continue to maintain and invest in these facilities to ensure consistent, safe, and reliable performance over the current planned asset life, regardless of whether a decision is made to refurbish these plants in order to extend their lives further.

Pickering B and Darlington Refurbishment Projects

Based on current plans, Pickering B's estimated end of life is 2014 - 2016 while Darlington estimated end of life is 2018 - 2020. In June 2006, the Ontario government directed OPG to begin economic feasibility studies on refurbishing its existing nuclear plants, and to begin an environmental assessment.

OPG has initiated phase 1 of the Pickering B and Darlington refurbishment projects, consisting of:

- Assessing options for refurbishment and continuing to operate nuclear units beyond their currently-predicted end of service life.
- Preparing a recommendation to the OPG Board with respect to Pickering B refurbishment.

New Nuclear Project

Also in June 2006, OPG was directed by its shareholder to begin investigating new nuclear generation. Specifically, OPG was directed to begin a federal approvals process, including an environmental assessment for new nuclear units at an existing site. OPG is conducting the initial planning of the work required to obtain the necessary federal approvals, including planning for an environmental assessment under the *Canadian Environmental Assessment Act* and initiating a review of available reactor designs (collaboratively with Bruce Power).
Further information on these projects is provided in Ex. D2-T1-S3.

7.0 BACKGROUND ON PERFORMANCE

Beginning in 1997, OPG Nuclear began a series of programs to address a prior lack of investment in many aspects of its operations including maintaining the material condition of its nuclear assets. In 2003, concerns remained for OPG Nuclear's future performance capabilities. The most significant risk identified was that the material condition of the plants was deteriorating as the plants entered the mid-points of their respective plant lives, with the oldest plants exhibiting greater deterioration.

Pickering A Return to Service

In August 1999, OPG's Board of Directors approved a plan to restart the four units at Pickering A which had been laid up in 1997. The project to restart the units was the Pickering A return to service project.

The project commenced with Unit 4, which was declared commercially available in September 2003. With the direction and agreement of the shareholder, OPG commenced the return to service of Unit 1. In November 2005, Unit 1 was declared commercially available for service.

In August 2005, OPG made the decision not to proceed with the return to service of Units 2 and 3 on the basis that it would not be financially viable. OPG is in the process of placing Units 2 and 3 at Pickering A into safe store condition for the remaining life of the station and an additional 30-year period prior to dismantlement. This project involves de-fueling the reactors, removing all heavy water and reconfiguring the station, including the control room, as a two unit station.

Evidence on the relevant costs of the Pickering A return to service project can be found at Ex. J1-T1-S1. Evidence on the reconfiguring of the station to achieve isolation of Pickering A Units 1 and 4 from Pickering A Units 2 and 3, as well as relocation of common system controls that are currently located in Unit 2, can be found at Ex. D2-T1-S1.

Operating Units: Pickering B, Darlington, and Pickering A Unit 1 and 4

Since 2004, OPG Nuclear has focused on increased investment in the material condition of the units, while maintaining the focus on safety performance, with an expectation that over the long-term, performance and reliability of the stations will improve resulting in increased production. During the period 2004 - 2007, the investment in improved material conditions of the nuclear generating stations has focused on completing life cycle plans and addressing known life limiting issues on major components at Pickering B and Darlington.

The 2004 plan was to ensure that Darlington, the station with the most advanced design, would not deteriorate in performance due to material condition issues but rather would sustain its high capability performance. This increased investment was incorporated into the 2004 business plan.

Pickering B was performing at poor reliability levels and was entering into major component maintenance (e.g., pressure tube and steam generators work). The plan was to drive improvements in the system and component health programs by significant and focused investment so that by the time the major component outage work was complete in 2007, the plant's overall material condition will have been restored and the effort would then go towards sustaining the performance at the improved levels. The result is that material condition of Pickering B has trended positive with significant reduction in forced losses due to material condition, and lower backlogs. Forced losses and high backlogs are indicative of poor asset health.

The Pickering A units as they came back into service over 2003 - 2005 were subject to unplanned outages, which is typical of units that have been out of service for many years. The plan was to ensure that Pickering A operated at the high standards of backlog levels for top performing plants. However, reliability has continued to be a problem due to a series of emergent issues relating to material condition of the units.

In 2007, Pickering A and Pickering B performance was negatively impacted by two major one-time extraordinary events; the inadvertent release by a third party contractor of resin into the demineralized water system, and Pickering A electrical supply system (inter-station transfer bus) problems. These events are unrelated to overall plant material condition.

OPG has also incorporated significant safety improvements over this period, which enables OPG to more effectively to address material condition issues. Other issues related to physical aspects of safety include the completion of the auxiliary power system at Pickering. These major safety related achievements provide a strong foundation for achieving predictability in operations. These key elements are recognized by international standard agencies as standards of safe operation. OPG is the first nuclear generator in Canada to achieve certification from Technical Standards and Safety Association for pressure boundary work (safe operations issue). Other factors for sound, sustainable and good performance include addressing our long standing major destiny issues such as feeders, steam generator, turbine and pressure tube (spacer relocation) issues. These are all very complex, long duration and high cost efforts. The business has also heavily invested in material condition improvements driving down backlogs in corrective and elective maintenance. Overall, the business is not yet at the industry standard, but has made considerable progress in achieving this goal.

The business has also reconstituted its security requirements as per requirements of the CNSC, following world events.

Key Initiatives

A number of measures and initiatives have been undertaken or are in the process of starting up, in support of the objectives, specifically:

- Increasing the effort to reduce elective and corrective maintenance backlogs and focus additional resources on preventive maintenance programs. A new equipment performance improvement strategy will be implemented that is designed to ensure cost effective maintenance by better integrating the roles of (1) station work management with responsibility for programming work to be done within the station and outage planning, (2) station operations and maintenance with responsibility for planned, preventive and corrective maintenance of structures, systems, components or equipment, and (3) Nuclear Supply Chain with responsibility for procurement of materials and services.
- Improving outage planning and execution processes to minimize unanticipated production shortfalls and transition OPG to a more sustainable, reliable, and predictable performance state. Components of this initiative include improvements to outage scope control, outage planning, and resource allocation.
- Implementing a three-year cycle for planned outages at Darlington (compared to current two-year cycle) and transitioning at Pickering to outage durations of 45 to 50 days from the recent life cycle outages of up to 130 days.

- At Pickering B, evaluating requests for project investments in the context of an impending decision on refurbishment. An exception to this are current large, one-of-a-kind projects (security, used fuel disposal, and auxiliary power) which are nearing completion.
- Increasing and sustaining the level of generation. Expected generation ranges from 50 to 51 TWh throughout the test period, reflecting an increase in the combined fleet output over the 2005 - 2007 period.
- Improved project review and monitoring process. This initiative includes examining the project portfolio to ensure that the number of planned projects is reasonable, that estimates of benefits are duly challenged, taking into account the ability to deliver the work (resource availability, scheduling and access to plant/equipment) as well as manage the projects both in-house and through third parties.
- Supply Chain is part way through their performance improvement plan which commenced in 2005, with a focus on three broad program objectives that include: improving material availability, establishing a competent nuclear supply chain organization, and re-establishing commercial leverage.
- Improving organizational effectiveness by taking initiatives to develop and enhance capable leadership in OPG Nuclear, addressing the aging demographics of the OPG Nuclear workforce and focusing on human operational improvements, while ensuring an effective and engaged workforce.
- Ongoing review of key processes (using an industry based peer team approach), to increase efficiency and effectiveness.

8.0 NUCLEAR TARGETS

Nuclear establishes performance targets to support its business objectives and benchmarks its performance against a number of these targets. Benchmarking information is presented in section 9.0. The targets for the Nuclear Generating Stations for 2008 and 2009 are shown in the chart below.

Chart 2

Nuclear Generating Station Targets

MEASURE	2008	2009
Generation (TWH)		
Pickering A	7.1	7.3
Pickering B	15.7	16.0
Darlington	28.6	26.5
Total Nuclear	51.4	49.8
Production Unit Energy cost (PUEC) – ($/MW/h)		
Pickering A	76	77
Pickering B	50	50
Darlington	30	34
Nuclear Avg.	43	46
Unit Capability Factor - %		
Pickering A	79.0	81.4
Pickering B	86.6	88.6
Darlington	92.7	86.2
Nuclear Avg.	89.0	86.0
Nuclear Performance Index (NPI)		
Pickering A	61.5	65.5
Pickering B	67.5	78.8
Darlington	95.7	92.9
Nuclear Avg.	78.0	82.0
Elective Maintenance Backlogs (per unit)		
Pickering A	425	375
Pickering B	700	575
Darlington	350	325
Nuclear Avg.	505	435

Nuclear production unit energy cost ("PUEC") is a measure of the cost of generating one megawatt-hour of electricity. It is derived by dividing OM&A costs plus nuclear fuel costs by total energy produced. Standard industry practice is to include in OM&A costs, the allocated corporate costs and variable costs related to used fuel disposal and the disposal of low and intermediate level radioactive waste materials. However, the costs do not include the total cost of service, e.g., PUEC excludes costs such as depreciation, taxes, and capital costs.

Unit capability factor is a standard World Association of Nuclear Operators ("WANO") indicator of performance reliability. Unit capability factor is the percentage of maximum energy generation that a unit or plant is capable of supplying to the electrical grid, limited only by factors within control of plant management. Unit capability factor is derived as the ratio of generation available from a unit over a specified time period divided by the maximum generation that the unit is able to produce under ambient conditions and at maximum reactor power during the same period. The available generation is reduced by planned and unplanned production losses deemed under station management's control. However, the derivation of available generation is not affected by losses due to events not under station management's control, including environmental conditions (e.g., loss of transmission capability, lake water temperature derates, labour disputes and low demand periods). While these events do impact actual production, they do not penalize unit capability factor as the units themselves are considered available to produce at these times. A high unit capability factor is indicative of excellence in plant physical asset condition, adherence to effective plant programs and practices to minimize unplanned energy losses and to optimize planned outages. Unit capability factor is usually presented as an average over a multi-year period in order to smooth out differing outage patterns etc.

The nuclear performance index ("NPI") is a weighted average of ten WANO indicators. It provides an overall measure of plant safety and reliability performance (70/30, safety related/reliability split) based on a number of reliability and safety measures. It is a measure of operational excellence. Plants with high NPI values have historically proven to be industry's top performers in costs and capacity factor. The inputs used are multi year data to provide a more consistent view (e.g., unit capability factor is averaged over two years.)

Elective maintenance backlogs measures pro-active investment in maintenance of plant equipment to maintain plant condition and enhance future reliability. A lower number indicates that plant equipment is being well maintained. Industry data indicate that well performing plants maintain backlogs at 350 - 400 per unit.

9.0 NUCLEAR FACILITIES BENCHMARKING

9.1 Establishing Industry Peer Groups

Nuclear benchmarks performance against CANDU nuclear plants as well as against the U.S. nuclear generators to assess and drive performance of its stations, as well as to identify opportunities for improvement from others. However, there are limits to OPG's ability to benchmark Pickering A and B due to lack of appropriate peer groups.

As reactor designs evolved from the late 1960's to the early 1990's, reactors tended to become larger, growing from 400 MW electrical output to 1300 MW electrical output. They also began to be grouped into multi-unit sites, generally in pairs in North America. Only OPG built four-unit stations. There was also a trend to greater complexity, more redundancy, more regulatory requirements such as seismic qualification, environmental qualification, and greater defense against accidents.

Darlington falls into the latest generation of North American reactors. Its large unit size and its multi-unit site are typical of U.S. stations built in the 1980s, although Darlington contains more common interconnected station systems. Cost and performance comparisons with those stations therefore, are reasonably valid.

Pickering A and Pickering B however are non-typical. At approximately 2100 MW, Pickering B falls into the mid range of U.S. stations in terms of total size. However the small size of its reactors places it at the bottom of the reactor size range. In fact, there are only five stations out of 72 in North America (U.S. and Canada) with smaller reactors and one of them is Pickering A. The four American reactors are all single unit stations with an average age of 35 years. Pickering A and Pickering B are older vintage and design. The two plants being of different designs but connected together (vacuum building, common services) adds to the complexity (cost) of operation of this facility.

Pickering B therefore, as a large station with small reactors, has no appropriate peer group. Benchmarking Pickering B with small reactors disregards the significant cost-benefit of a multi-unit site. On the other hand, comparing it with similar size stations places it at a disadvantage because of its small unit size. However, OPG uses the latter approach while incorporating correction factors, where appropriate, for reactor size.

Pickering A, as a multi-unit station with small reactors, also has no appropriate peer group.

It is worth noting that the size of units primarily impacts on cost, and not on performance.

9.2 Benchmarking Results

The measures that are benchmarked are: unit capability factor, NPI, PUEC, and elective maintenance backlogs (see section 8.0 above for additional information on these measures). These measures represent essential parameters of good and sustainable nuclear performance.

Nuclear uses two sources for benchmarking:

- World Association of Nuclear Operators - for non-cost performance data
- Electric Utility Cost Group (“EUCG Inc.”) - for cost performance data

Information on the two organizations and the facilities included in their benchmarking is provided in Appendix A.

Benchmarking results are presented in Chart 3 and then discussed in additional detail below:

Chart 3
Nuclear Benchmarking Results

Measure		Value*	Comparison	Source and Peer Group
Production Unit Energy Costs "PUEC" ($/MWh Can$)	Pickering A	68	US industry median is 24 $/MWh, US top quartile is 20 $/MWh. PA/PB U.S size peer group median 32 $/MWh DN U.S. size peer group median 23 $/MWh	EUCG** for 2006 (CANDU worldwide PUEC data is not available) U.S. – Can. $ Fx rate 0.88
	Pickering B	50		
	Darlington	26		
	Nuclear	48		
Unit Capability Factor (%)	Pickering A	69.6	CANDU : Median: 86.4 Top quartile: 92.4.	OPG/WANO data: three year average. CANDU unit capability factor scores include OPG
	Pickering B	74.3		
	Darlington	89.2		
	Nuclear	81.4		
Nuclear Performance Index (NPI)	Pickering A	56.6	CANDU: Median: 74.6; Top quartile: 85.8	OPG/WANO NPI data: up to 3 year averages for various components CANDU NPI scores exclude OPG
	Pickering B	56.9		
	Darlington	92.7		
	Nuclear	68.7		
Elective Maintenance Backlogs (# outstanding per unit)	Pickering A	450	US industry median: 348; US top quartile: 304	Sourced from WANO working group but not standard WANO measure. One year data for OPG/WANO.
	Pickering B	850		
	Darlington	400		
	Nuclear avg.	590		

*OPG benchmark data are based on current business plan information provided to the Shareholder.
**EUCG cost data are always in U.S. dollars of the year, and are not normalized in any way for unit size, age, or technology differences.

1.0 <u>Production Unit Energy Cost</u>

External information is collected via EUCG, a non-profit organization whose membership includes 99 percent of U.S. nuclear operators, as well as many others outside of the U.S. The organization collects, validates, and publishes blinded cost and production data to members. It is standard industry practice to benchmark costs by comparing the cost of production.

Darlington continues to perform very well, relative to its peer group, at $26/MWh. OPG has budgeted adequate OM&A and capital investments to ensure that Darlington's material plant condition and performance is sustained**,** as is further discussed in Exhibits D and F. Darlington is expected to further improve on this as its generation output improves.

The 2006 PUEC for Pickering B is $50/MWh. This is high for its peer group, mainly due to lower production levels and higher costs as the plant elective backlogs are reduced and life cycle outages completed. Pickering B is also an older vintage plant with smaller size units – both representing negative impacts for unit energy costs.

OPG currently does not use PUEC to benchmark Pickering A since it is not yet a meaningful measure. For completeness it has been included in this benchmarking data presentation, although it is not factored into the overall Nuclear PUEC benchmark. The plant was idle from 1997 until the restart of Units 1 and 4. Because of the transition from four to two unit operation, Pickering A has not yet achieved a stable cost profile so as to allow for the meaningful use of PUEC for benchmarking. OPG expects that Pickering A will be in a position to be effectively benchmarked in 2008, when it is more firmly established in a steady state of operation.

In addition to costs, PUEC is also impacted by generation output. Overall, the U.S. industry (pressurized water reactors/boiling water reactors) has achieved a stable "high level" of generation performance. The U.S. nuclear industry began improvement programs earlier and have achieved a steady state of top level performance in cost and output. OPG is moving in the same direction, but with the exception of Darlington, has not yet achieved this level.

The Pickering plants are making significant investments to improve the level of performance (e.g., improving material condition of plant, reducing corrective and elective maintenance backlogs). It is therefore difficult to make a meaningful comparison based solely on unit cost.

In addition, there are other factors which must be considered when assessing benchmarks for OPG plants. These include fluctuations in the Canada – U.S. currency exchange rate, accounting differences, and technology differences. While performance data across the industry are standard, the same cannot be said for the cost data. Although the EUCG strives for consistency, openness and accuracy in reporting cost data through various data audit reviews, it relies on the integrity of the data submitters. In addition, varying accounting models (e.g., allocation of corporate overhead and capitalization policies) can affect the way costs are interpreted. These aspects of variability include:

a. Canada – U.S. Dollar Exchange Rate Distortion

The cost comparisons and trending currently being used covers the years 2003 - 2006. The Canadian dollar has appreciated by almost 25 percent against the U.S. dollar during this four year period (almost 40 percent since 2002). All other things remaining equal, this has tended to show OPG costs as rising against the U.S. industry, thus distorting the comparison. The large shift in the Canadian – U.S. dollar exchange rate impacts the ability to trend costs over this time period.

b. Accounting Differences

When looking at operating costs, there are differences created by capitalization policies which vary between companies. Some companies allow more costs to be capitalized than others. This alters the costs which go into the production cost calculation. Also the way corporate costs are allocated to the plants can effect the cost calculation.

c. Technology Differences between CANDU and Pressurized Water Reactors/Boiling Water Reactors

The principal differences between reactor types are presented below. The emphasis is on differences that result in different costs. Of the world reactor fleet of 436 units, 265 or 61 percent are pressurized water reactors. Ninety-two or 21 percent are boiling water reactors, and 39 or 9 percent are CANDU type. The remaining units are mainly gas cooled reactors.

Chart 4

Technology Differences between CANDU and Pressurized Water Reactors/ Boiling Water Reactors

Components	**Pickering A**	**Pickering B**	**Darlington**	**Pressurized Water Reactor**	**Boiling Water Reactor**
Reactor	Horizontal pressure tubes	Horizontal pressure tubes	Horizontal pressure tubes	Pressure vessel	Pressure vessel
Reactor coolant and associated systems	Heavy water	Heavy water	Heavy water	Light water	Light water
Generator Output	540MW	540MW	934MW	500-1400 MW	500 – 1400 MW
Steam Generators (SG)/unit	12	12	4	2 - 4	NA
Main Coolant Pumps/unit	16	16	4	2 - 4	2
Large Isolation Valves Main Circuit	40/unit	40/unit	0	0	4/unit
Standby Generators & Emergency Power Generator	6 for 4 units	8 for 4 units	6 for 4 units	2/unit	2/unit
Computers/unit	2	2	8	1	1
Shut Down Systems/unit	2	2	2	2	2
On line Fuelling Machines	8 for 4 units	8 for 4 units	6 for 4 units	NA	NA
Tritium Removal Facility	0	0	1	NA	NA
Heat Transport System	Carbon steel	Carbon steel	Carbon steel	Stainless steel	Stainless steel

The major difference between OPG's CANDU and light water reactors (typical U.S. reactors) designs is that CANDU reactors use natural uranium for fuel, while U.S. reactors use uranium that has been enriched to higher levels of the fissile isotope, Uranium-235. This difference in fuel types necessitates major differences in technology used to support operations. This in turn drives economic differences. Examples are discussed below.

- CANDU units must use heavy water instead of light water in the moderator and heat transport systems. Management of the reactor coolant is more costly in a CANDU since the heavy water itself is more costly and also since it is more radioactive than the U.S. light water coolant due to the presence of tritium – creating a "costlier" work environment (e.g., work in plastic suits, increased monitoring etc.).
- In the OPG CANDU design, units are connected to each other by a common vacuum building containment system (safety feature at some CANDU sites). This common containment system necessitates that all units be taken off-line at the same time once every 10 to 12 years to conduct required inspections of these components. At Darlington this applies to four units while at Pickering it applies to all six operating units. These are typically complex major outages and have a significant impact on generation output.
- CANDU units must use on-line fuelling, with a consequent cost premium for sophisticated robotics and a permanent fuelling organization.
- CANDU units must have the fuel contained in pressure tubes to allow on-line fuelling. This requires additional inspection and maintenance which pressurized water reactors pressurized water reactors/boiling water reactor reactors do not have to undergo.
- The generally larger equipment inventory in a CANDU unit compared to the pressurized water reactor's/boiling water reactor's units represents a net increase in maintenance and operations workload.

The disadvantages above are offset to some extent by the advantage in the cost of fuel since natural uranium is less expensive than enriched. In addition, with on-line refueling, CANDU units should be capable of longer operating intervals between outages. The pressurized water reactors / boiling water reactors, without on-line fueling, are limited by fuel "burn-up". They must shut down to refuel every 18 to 24 months, whereas CANDU units may operate up to 36 months between outages.

There are some economic “spin-offs” from operating with natural uranium and heavy water which the other reactors do not have. These include tritium and cobalt sales (see Exhibit G2). Finally, irradiated natural uranium (“spent fuel”) is less hazardous to handle and store than enriched uranium.

2.0 Unit Capability Factor

With reference to unit capability factor, Darlington has continued to perform as one of the better CANDU plants world wide. Pickering B performance is below equivalent world wide CANDU due to major fuel channel outages and unplanned production losses. The performance of the Pickering A units, which came back into service over 2003-2005, has also been below equivalent world wide CANDU.

In 2007, Pickering A and Pickering B unit capability factors were also negatively impacted by two major one-time extraordinary events: the inadvertent release by a third party contractor of resin into the demineralized water system, and Pickering A electrical supply system (inter-station transfer bus) problems.

The expectation for 2008 and 2009, as a result of improvements made in plant material condition, is that performance will rebound at both the Pickering A and Pickering B stations. The target unit capability factor for Pickering B in 2008 and 2009 will place Pickering B within median CANDU equivalent. Pickering A unit capability factor is also expected to improve but will remain below the median CANDU equivalent.

3.0 Elective Maintenance Backlogs

With a large elective backlog, OPG’s nuclear fleet continues to lag in comparison to similar performance indicators for U.S. nuclear generating facilities, reflecting a lack of past investment in plant material condition. OPG will be increasing investments to help reduce elective maintenance backlogs. There is a consensus within the U.S. nuclear industry with regard to the acceptable level of elective maintenance backlogs for a well run plant. It is usually 350 to 400 per unit.

4.0 Nuclear Performance Index

The world CANDU median score (excluding OPG units) for Q1 2007 is 74.6, while the top quartile is 85.8. Darlington at 92.7, is thus in the upper end of the top quartile for world CANDU reactors. Pickering B is at 56.9 and Pickering A is at 56.6.

As noted previously, NPI is a weighted average of several WANO indicators. It provides an overall measure of plant safety and reliability performance (70/30, safety/reliability split) based on a number of reliability and safety measures. The low NPI scores at Pickering A and Pickering B are driven by generation performance results. The stations are recovering from lengthy planned outages to address major life cycle and backlog issues. The results also reflect the high forced loss rates due to the poor material condition, which are expected to reduce as the backlog reduction and material condition improvement work takes effect. It is important to underline that OPG Nuclear's NPI safety-related indicators average considerably better than the generation areas. Thus it is largely the generation scores that are lowering total NPI score.

Output

Generation performance is heavily weighted in NPI calculations:

- Unit capability factor (weight 15 percent)
- Forced loss rate (weight 15 percent)

Safety Related

Nuclear Safety:

- Unplanned automatic scrams (weight: 10 percent).
- High pressure injection (weight: 10 percent).
- Auxiliary boiler feedwater (weight: 10 percent).
- Emergency AC power (weight: 10 percent).

Asset Health:

- Chemistry performance index (weight: 5 percent)
- Fuel reliability (weight: 10 percent).

Worker Safety:

- Collective radiation exposure (weight: 10 percent)
- Industrial safety accident rate (weight: 5 percent).

The chart, below, shows a breakdown of the NPI index into its components and compares OPG to world fleet of CANDU reactors. It is calculated over a two year period.

Chart 5

NPI Index

		Out of points	Excluding OPG CANDU Benchmarks Q1-2007		Total Points OPG Q2 2007		
			TOP Q avg	World Median	PA	PB	DN
Output	UCF FLR	**30**	**29.2**	**20.5**	**0.0**	**0.8**	**22.9**
Nuclear Safety	RTR HPSI ABFW EACP	**40**	**40.0**	**40.0**	**34.4**	**38.6**	**40.0**
Asset Health	CPI FRI	**15**	**15.0**	**15.0**	**7.2**	**10.2**	**14.8**
Worker Safety	CRE ISAR	**15**	**15.0**	**7.8**	**15.0**	**7.3**	**15.0**
				Total	**56.6**	**56.9**	**92.7**

Source: WANO

At Pickering B, the NPI score is negatively impacted by a low collective radiation exposure score. This is a result of lengthy, extensive planned outages in 2005, 2006 and 2007. Despite this, it is important to note that all plants remain well below prescribed limits.

At no time have any of the three OPG plants exceeded either Canadian Nuclear Safety Commission mandated dose limits, or the more restrictive OPG corporate limits.

LIST OF ATTACHMENTS

APPENDIX A
Benchmarking Sources

Nuclear uses primary two sources for benchmarking:

- World Association of Nuclear Operators
- Electric Utility Cost Group

<u>World Association of Nuclear Operators</u>

OPG Nuclear participates in the World Association of Nuclear Operators database, which is updated quarterly by utilities across the world. The database does not contain cost data, but it does encompass industry standard performance indicators, including unit capability factor, unplanned capability loss factor, forced loss rate, safety performance etc.

<u>Electric Utility Cost Group</u>

This is an industry association which shares “blinded” historical cost information amongst members in fossil, hydro-electric and nuclear forms of generation. The EUCG nuclear membership currently includes 99 percent of the commercial operators in the U.S., as well as many overseas. OPG, Bruce Power, and Hydro Quebec are the Canadian members. EUCG cost data are used to compare Nuclear’s production costs to industry peers (on a fleet, site or unit basis). The EUCG affords the opportunity to compare functional costs and activity based costs.

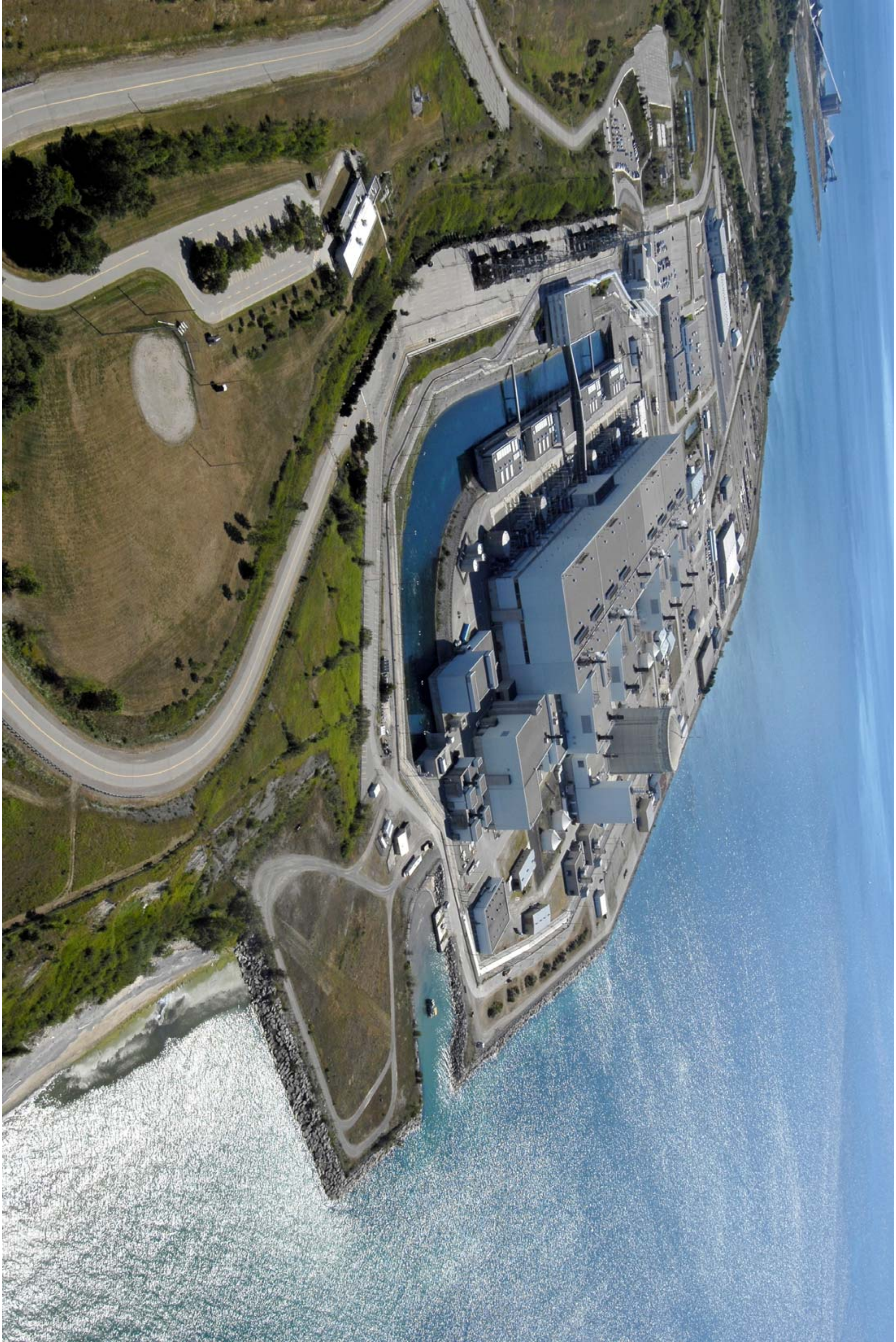
The primary goal of the EUCG is to enable member companies to optimize costs and reliability performance of participating plants through economic comparison and benchmarking studies. To achieve these objectives, the EUCG operates a database for comparing nuclear plant costs, staffing, and performance data. This database was originally developed in 1986.

ATTACHMENT A

Photo of Darlington Generating Station

ATTACHMENT B

Photo of Pickering Generating Station



ONTARIO POWER GENERATION

President and CEO

- Finance SVP & Chief Financial Officer
  - VP, Financial Planning & Corp Finance
  - VP, Treasury
  - VP Financial Services Controller
  - Chief Risk Officer
  - Nuclear Finance Vice President
  - VP Corp. Investment Planning
- Human Resources SVP & Chief Ethics Officer
  - VP, Nuclear HR & Employee Safety
  - VP, Fossil HR & Employee Safety
  - VP, Corporate HR & Employee Safety
  - VP, Labour Relations
  - VP, Compensation & Benefits
  - VP, Hydro HR & Employee Safety
- Law Division SVP, Law & Gen. Counsel
  - Supply Chain Governance Asst. Gen. Counsel
  - Large Projects Asst. Gen..Counsel
  - General Corporate Asst. Gen..Counsel
  - Labour/Employment Solicitor
  - Regulatory/Environment Asst. Gen..Counsel
- Energy Markets EVP Corporate Development
  - VP, Electricity Sales & Trading
  - VP, Sustainable Development
  - VP, Real Estate & Services
- Corporate Affairs SVP Corporate Affairs
  - VP, Regulatory Affairs & Corp. Strategy
  - VP, Public Affairs
  - CIO
    - VP, Service Delivery
    - VP, Enterprise Strategy & Architecture
    - VP, Customer Relationship & Mgmt.
- Corporate Secretary VP Corporate Secretary
  - Assistant Board Secretary

Operations EVP & Chief Operating Officer

- Nuclear Waste Management SVP
  - VP, Nuc.Waste Operations
- Nucl. Generation Develop. & Services Unit SVP
  - SVP Nucl. Generation Development
  - VP, Inspection and Maintenance Services
- Nuclear Chief Nuclear Officer
  - SVP, Pickering A
  - SVP, Pickering B
  - SVP, Darlington
  - SVP, Nuclear Programs & Training
  - VP, Eng. & Modifications, & Chief N.E
  - VP, Nuclear Supply Chain
  - VP, Performance Improve. & Nuclear Oversight
- Fossil EVP Fossil
  - Bus. Development VP, Projects
  - Plant Mgr, Nanticoke GS
  - Plant Mgr, Northwest
  - Plant Mgr, Lennox GS
  - Plant Mgr, Lambton GS
- Hydro EVP Hydro
  - VP, Hydroelectric Development
  - Plant Mgr, Niagara Plant Group
  - Plant Mgr. NE Plant Group & Evergreen Energy
  - Plant Mgr. Hydro NW Plant Group
  - Special Projects Plant Manager Hvdroelectric
  - Plant Manager Ottawa/St. Lawrence

SUMMARY OF LEGISLATIVE FRAMEWORK

1.0 PURPOSE

The purpose of this evidence is to provide a summary of the legislative framework that applies to OPG's prescribed facilities.

2.0 INTRODUCTION

OPG is subject to provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies whose powers are derived from such legislation or regulations (i.e., the Ontario Energy Board, the Independent Electricity System Operator or the Canadian Nuclear Safety Commission), and to Canada's international obligations under certain international treaties (i.e., regarding international boundary waters and nuclear safeguards). Collectively, these sources dictate many of the constraints within which OPG is permitted to operate its prescribed facilities and manage its business. Many of these regulatory requirements affect OPG's costs and revenues in ways not experienced by other businesses or utilities. In addition, regulatory requirements can require changes that can affect the operation of OPG's prescribed facilities or OPG's policies, processes, work programs and training needs. The need to respond to and implement such changes also gives rise to cost implications for OPG, both short-term and long-term. This exhibit summarizes the key legislation, regulations, and other governmental requirements that govern OPG, to which OPG must be responsive and that represent key cost drivers to OPG, particularly in respect of the prescribed facilities.

3.0 *ONTARIO ENERGY BOARD ACT, 1998*

The *Ontario Energy Board Act, 1998* ("Act"), when read in conjunction with Ontario Regulation 53/05, as amended ("Regulation"), establishes that OPG is a prescribed generator for the purposes of section 78.1 of the Act. As such, section 78.1 provides that OPG is entitled to receive payments with respect to output from generating units at the following facilities, which have been prescribed by the Regulation:

<u>Regulated Hydroelectric Facilities</u>

- The Niagara Plant Group, comprised of:
  - Sir Adam Beck I Generating Station
  - Sir Adam Beck II Generating Station
  - Sir Adam Beck Pump Generating Station
  - DeCew Falls I Generating Station
  - DeCew Falls II Generating Station
- R. H. Saunders Generating Station

Nuclear Facilities

- Pickering A Generating Station
- Pickering B Generating Station
- Darlington Generating Station

The Regulation establishes April 1, 2008 as the earliest possible date for the OEB to make its first order establishing payments under section 78.1 of the Act. For the period after the OEB issues its first order under section 78.1, the payment amounts for the output from the prescribed facilities are to be determined in accordance with the order of the OEB then in effect. For the period from April 1, 2005 until the day that the OEB's first order under section 78.1 becomes effective (i.e., the interim period), payment amounts are determined in accordance with the Regulation. Section 78.1 further provides that the OEB must make its orders in accordance with the rules that are set out in the Regulation, which include rules concerning the establishment of deferral and variance accounts, among other things.

The relevant provisions of the Act are provided at Appendix A to this exhibit. The Regulation, in its entirety, is provided at Appendix B.

4.0 *ELECTRICITY ACT, 1998*

Part IV.1 of the *Electricity Act, 1998* is of direct application to OPG. The provisions set out in this Part of the *Electricity Act, 1998* establish the objects of OPG as well as certain basic obligations on OPG to provide reports to its shareholder.

5.0 ELECTRICITY MARKETS

Under authority granted to it by the *Electricity Act, 1998*, the Independent Electricity System Operator ("IESO") administers and ensures compliance with the Market Rules for the Ontario Electricity Market (the "Market Rules"). All of OPG's prescribed generating facilities are registered participants in the IESO-controlled markets and are therefore obligated to comply with all applicable Market Rules. The Market Rules govern the IESO-controlled grid and establish and govern competitive markets for the wholesale sale and purchase of electricity and ancillary services in Ontario. Among other things, the Market Rules include provisions:

- Governing the conveying of electricity into, through or out of the IESO-controlled grid and the provision of ancillary services.
- Governing the terms and conditions for authorization to participate in the IESO-administered market or to cause or permit electricity to be conveyed into, through or out of the IESO-controlled grid.
- Governing the manner in which electricity and ancillary services are sold, purchased, and dispatched in the IESO-administered markets.

OPG's operation of the prescribed facilities is therefore significantly influenced by the requirements of the Market Rules.

6.0 OEB LICENCE

OPG is the holder of an Electricity Generation Licence (EG-2003-0104) from the OEB, which is valid until October 30, 2023 (the "Licence"). The Licence is provided in Appendix C. The Licence applies to all generating stations that are owned or owned and operated by OPG, including the prescribed facilities. The Licence obligates OPG to comply with all applicable provisions of the *Ontario Energy Board Act*, the *Electricity Act*, all regulations under these Acts, as well as all applicable Market Rules. The Licence further obligates OPG to enter into agreements for the supply of energy or ancillary services where the IESO deems necessary for the purpose of maintaining the reliability and security of the IESO-controlled electricity grid. Ancillary services provided by the regulated hydroelectric facilities are discussed at Ex. G1-T1-S1 and for the nuclear facilities at Ex. G2-T1-S1. The Licence includes a condition which results in a requirement for OPG to offer all available capacity into the IESO markets, consistent with good utility practice.

7.0 REGULATED HYDROELECTRIC FACILITIES

OPG's regulated hydroelectric facilities are subject to international treaties between Canada and the United States, federal and provincial regulatory and legislative requirements, and the common law as it pertains to riparian interests, waterways, and real property. Collectively these laws and requirements impose various costs and constraints on the operation and management of these facilities. Of particular note are the complex body of constraints that, along with the natural variations in water levels that OPG must contend with, govern the availability of water for OPG's use in generating electricity at these facilities. These regulatory constraints are particularly complex and cumbersome for the regulated hydroelectric facilities because these facilities are supplied by international boundary waters (the Niagara River and the St. Lawrence River). Also of note are OPG's dam safety activities and programs that relate to each of the 30 dams that are associated with the regulated hydroelectric facilities. Regulatory regimes that are uniquely applicable to OPG's prescribed hydroelectric generating facilities are in the areas of rights to use water for the purposes of generation, dam safety, and environmental protection. The key regulatory obligations and constraints applicable to the regulated hydroelectric facilities are highlighted below.

<u>Water Rights and Usage:</u>

- The *Public Lands Act* (Ontario), pursuant to which OPG has been granted a water power lease for the R. H. Saunders Generating Station.
- The *Niagara Parks Act,* pursuant to which OPG has been granted a water power lease for the Beck I Generating Station and the Beck II Generating Station.
- The *Boundary Waters Treaty of 1909* between Canada and the United States which governs the use and coordination of all boundary waters between Canada and the United States, including the Niagara and St. Lawrence Rivers, and creates the International Joint Commission which has a mandate to prevent and resolve disputes over the use of boundary waters and to monitor activities regarding boundary waters to ensure that the

countries are complying with the terms of the Treaty and to ensure that the interests of both countries are protected.

- The *Niagara Diversion Treaty of 1950* between Canada and the United States which, among other things, terminated certain sections of the Boundary Waters Treaty of 1909, provided for the construction and operation of the International Niagara Control Works, determined the priority of use of the waters of the Welland Canal and the Niagara River, and set minimum flow requirements over Niagara Falls.
- Memoranda of Understanding for Joint Works between OPG and the New York Power Authority, which provide obligations to operate and maintain certain international works and cost sharing mechanisms for such works, including the International Niagara Control Structure. OPG and New York Power Authority have entered into separate Memoranda of Understandings for each of the Niagara and the St. Lawrence Rivers.
- Memorandum of Understanding between OPG and the New York Power Authority which provides, among other things, for the coordination of generation as between the parties to maximize generation from the total amount of water available for generation pursuant to the relevant Treaties through water transactions.
- *Electricity Act, 1998,* section 92.1, which specifies a gross revenue charge which is a tax and charge imposed on owners of hydroelectric generating stations, consisting of a property tax component and a water power lease component.

Dam Safety:

- OPG's Dam Safety Policy and Program operates largely in the absence of government requirements or guidelines, but is nevertheless critical for safety associated with the regulated hydroelectric facilities and their operations.
- Dam safety requirements have been under development by the Ontario Ministry of Natural Resources since 1999 and are expected to become the basis for a new regulation under the *Lakes and Rivers Improvement Act* sometime in 2008. Based on OPG's preliminary review of the most recent draft of the regulation, which is subject to change, OPG does not anticipate major capital improvement costs for dams or hydraulic structures associated with the regulated hydroelectric facilities, though annual dam registration fees and increased engineering costs are expected to result.

- The *Lakes and Rivers Improvement Act* requires OPG to obtain approvals for the construction, alteration, improvement, or repair of dams.
- The International Joint Commission has jurisdiction over all cases involving the use or obstruction or diversion of boundary waters, including certain dams and structures situated in the international waters of the Niagara and St. Lawrence Rivers.
- OPG's Waterway Public Safety Program operates largely in the absence of government requirements or guidelines, but is nevertheless critical for safety associated with the regulated hydroelectric facilities and their operations, and is driven by OPG's high level of corporate responsibility and due diligence.
- Waterway public safety requirements may be incorporated into dam safety regulations currently under development by the Ontario Ministry of Natural Resources.

<u>Environmental:</u>

- *Fisheries Act* (Canada), which requires that authorization be obtained for construction that results in the destruction of fish or the harmful alteration, disruption or destruction of fish habitat. Such authorization may be conditional upon the provision of compensation for harm to fish habitat, including by means of funding habitat enhancement, as has been the case for the Niagara Tunnel project.
- *Conservation Authorities Act* (Ontario), which grants authority – for example, to the Niagara Peninsula Conservation Authority in the Niagara area and the Raisin Region Conservation Authority in the area that includes the R. H. Saunders facility – to make regulations that restrict, prohibit, require permission for or otherwise regulate matters that include the use of water; the changing or diverting of or interference with watercourses; or the undertaking of development in certain areas that may affect flooding, erosion, pollution or conservation.
- *Environmental Assessment Act* (Ontario), which requires completion of an environmental assessment process and associated consultation activities where station upgrades or other projects result in an increase in generation over a regulated threshold level.
- *Environmental Protection Act* (Ontario), which is the main environmental protection legislation in Ontario that, among other things, prohibits the unauthorized discharge of contaminants into the natural environment, regulates the management and disposal of

wastes, imposes requirements for responding to and reporting non-compliance events, and imposes duties on the directors and officers of OPG in respect of environmental performance.

- *Ontario Water Resources Act* (Ontario), which requires approvals for the discharge of wastewater (i.e., oily water treatment systems at the regulated facilities) as well as permits to take water over a specified amount. Regarding permits to take water, recent changes to regulations under this Act may remove a grandfathering provision for permits to take water. Accordingly, permits to take water may in future be required for water that is temporarily diverted for the generation of hydroelectric power, thereby imposing additional constraints and potential costs on OPG.
- *Endangered Species Act, 2007*, which requires permits to be obtained, with conditions, in order to engage in activities that could damage or destroy the habitats of species, such as certain fish, that are listed as being protected under this Act.
- ISO 14001 Environmental Management System standard, to which OPG's prescribed hydroelectric facilities are certified and which provides a recognized program that OPG follows to ensure due diligence and to assist OPG in achieving compliance with regulatory requirements, such as those set out in the *Environmental Protection Act.*

OPG's regulated hydroelectric facilities are also subject to relevant municipal by-laws that apply locally, as well as to more generally applicable legislative and regulatory requirements such as in areas that include, but which are not limited to:

- Technical standards and safety including corresponding regulations and codes, particularly in respect of fuel storage tanks;
- Heritage;
- Dangerous goods transportation;
- Occupational health and safety;
- Employment standards;
- Labour relations;
- Freedom of information.

8.0 NUCLEAR GENERATING FACILITIES

8.1 Nuclear Operations and Materials

OPG's nuclear operations are subject to a large number of regulatory requirements, particularly under federal statutes and associated regulations that specifically govern the nuclear industry, nuclear materials, nuclear liability, and nuclear facilities. Accordingly, OPG's nuclear operations are subject to the jurisdiction of the Canadian Nuclear Safety Commission ("CNSC"), an independent federal government agency that derives its powers from, and is responsible for administering, ensuring compliance with and enforcing the *Nuclear Safety and Control Act (Canada)*, which is described below. While the nuclear regulatory regime to which OPG is subject helps to ensure and guide OPG in the safe and secure operation of its nuclear facilities, it is a regime that is particularly rigorous and highly prescriptive in nature. As a result, these requirements are a significant driver of costs and operational constraints for OPG in respect of its nuclear operations. Several of the key regulatory regimes that are uniquely applicable to OPG's nuclear facilities are discussed below.

The purpose of the *Nuclear Safety and Control Act* (Canada) is to limit the risks to national security, health and the safety of persons and the environment that are associated with the development, production and use of nuclear energy, as well as to limit risks associated with the production, possession and use of nuclear substances, certain equipment and certain related information. This Act also implements particular measures to which Canada has agreed respecting international control of the development, production and use of nuclear energy, including the non-proliferation of nuclear weapons and nuclear explosive devices. In addition, this Act establishes the CNSC and delineates the powers of the Commission.

The CNSC is authorized under this Act to regulate the development, production and use of nuclear energy, as well as to regulate the production, possession, use and transport of nuclear substances and prescribed equipment. As such, the CNSC's regulatory control extends to equipment, construction and maintenance activities at the prescribed facilities, as well as plant operations and the oversight of safety programs. The CNSC exercises its mandate in respect of OPG's nuclear operations largely by means of the issuance of operating licences and amendments, as well as through continuous monitoring and inspections to ensure compliance with operating licences, relevant standards and applicable regulations. These licences, which must be renewed approximately every five years for the generating stations (or ten years in respect of certain nuclear waste facilities), impose numerous conditions and constraints on OPG, including obligations to comply with Regulatory Guidance Documents issued by the CNSC and various external standards and codes (i.e., National Building Code, National Fire Code).

OPG holds three Power Reactor Operating Licences from the CNSC, which allow for operation of the Pickering A, Pickering B, and Darlington generating stations, as well as separate licences that authorize the operation of nuclear waste management facilities. In addition, OPG holds licences for nuclear waste packaging, the construction of new waste management facilities and the possession, transport, and import/export of various nuclear substances. Further discussion of the applicability of the *Nuclear Safety and Control Act* (Canada) to OPG's management of nuclear waste is set out at Ex. H1-T1-S1. In addition to the resources and costs associated with compliance with the conditions in these licences, the application process for each such licence, including for significant amendments or renewal, requires extensive preparation and the conduct of public hearings involving CNSC staff and intervening stakeholders. A list of all key licenses related to OPG's nuclear facilities is attached as Ex. A1-T6-S1 Appendix D.

Also significant is the CNSC's power under the *Nuclear Safety and Control Act* to make regulations in the licensing area. OPG's nuclear facilities are required to operate in accordance with numerous regulations under this Act, including the following:

- General Nuclear Safety and Control Regulations.
- Class 1 Nuclear Facilities Regulations.
- Packaging and Transport of Nuclear Substances Regulations.
- Nuclear Security Regulations.
- Nuclear Non-proliferation Import and Export Control Regulations.
- CNSC Cost Recovery Fees Regulations.

A person or organization may only possess or dispose of nuclear substances, or construct, operate and decommission nuclear facilities in accordance with the terms of a licence issued by the CNSC, with such terms incorporating the applicable requirements set out in the regulations. When applying for such a licence, the applicant must demonstrate that they are qualified to carry out the activities authorized by the licence and that they "will, in carrying on that activity, make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed." OPG is also required, under such licences, to retain a significant amount of records in some cases for the life of the station and to provide routine reports on its operations to the CNSC. Compliance with international and national standards in relation to matters such as nuclear safeguards and radioactive emissions are other examples of conditions that are incorporated into station licences.

It is a fundamental principle of nuclear regulation that the licensee, in this case OPG, bears responsibility for the safe operation of nuclear facilities. The CNSC sets safety objectives in areas such as radiation protection, physical site security, and the transport of radioactive materials. OPG is required to design, implement, monitor, and continually improve upon its extensive programs in each of these critical areas. The CNSC audits OPG's performance against these objectives, continually monitors OPG's safety performance and reports annually to Parliament with an assessment of licensee performance in all areas of nuclear safety. The delivery and continual improvement of these programs represent a significant cost driver for OPG in respect of the regulated nuclear facilities.

To assist licensees in complying with the complex array of regulatory requirements, the CNSC also issues a variety of guidance documents. It is OPG's practice to incorporate the directions from these guidance documents into the design and operating documents for OPG's nuclear generating stations.

Heavy water, which is essential for the operation of OPG's nuclear generating stations, is a controlled substance under the *Nuclear Safety and Control Act*. Heavy water is noteworthy because, in addition to requiring authorization under a licence issued by the CNSC, the export and import of heavy water requires a permit issued by the Export Controls Division of the Department of External Affairs and International Trade. The requirements for export and import permits are stipulated by the *Export and Import Permits Act*. The Export Controls Division at the Department of Foreign Affairs and International Trade works with the CNSC to evaluate export and import applications. An import licence is required, allowing customers to return heavy water to OPG for upgrading and clean-up services. Exhibit G2-T1-S1 presents a detailed discussion of heavy water sales and services.

8.2 Civil Liability

OPG is subject to the *Nuclear Liability Act* (Canada), which governs civil liability for nuclear damage in Canada. The *Nuclear Liability Act* (Canada) imposes absolute and exclusive liability on a licensed operator of a nuclear generating station for any damage to property of, or personal injury to, the public arising from a nuclear incident. While operator liability is absolute and exclusive, it is also limited to $75M. Against this liability risk, the *Nuclear Liability Act* (Canada) requires all operators of nuclear generating stations in Canada, including OPG, to obtain insurance.

8.3 Nuclear Waste Management

The *Nuclear Safety and Control Act* provides the CNSC with authority over nuclear waste from a health, safety and environmental protection perspective. The CNSC licenses all of OPG's waste management facilities. OPG is also subject to the *Nuclear Fuel Waste Act* (Canada). The *Nuclear Fuel Waste Act* (Canada) addresses the long-term handling and disposal of used nuclear fuel.

Coincident with the formation of OPG on April 1, 1999, OPG and the Province of Ontario entered into the Ontario Nuclear Funds Agreement. The Ontario Nuclear Funds Agreement is an agreement that generally establishes the responsibilities for funding the nuclear waste management and decommissioning liabilities that OPG inherited from Ontario Hydro.

The *Nuclear Safety and Control Act*, the *Nuclear Fuel Waste Act* (Canada), and Ontario Nuclear Funds Agreement are discussed in greater detail at Ex. H1-T1-S1.

8.4 ENVIRONMENTAL

With respect to environmental matters, projects associated with OPG's nuclear facilities, including the nuclear waste management facilities, can, depending on fact-specific determinations, be subject to requirements for the preparation of costly and resource-intensive environmental assessments under the *Canadian Environmental Assessment Act* (Canada). In addition, nuclear operations are subject to a wide range of environmental legislation and regulation, both federal (i.e., *Fisheries Act, Canadian Environmental Protection Act, Transportation of Dangerous Goods Act*) and provincial (i.e., *Environmental Protection Act, Ontario Water Resources Act*), along with the associated costs of compliance and the need to respond to rapidly changing regulatory requirements in these areas. Several of these regimes were discussed above in the context of hydroelectric facilities. Also, like the hydroelectric facilities, OPG's nuclear generating facilities operate in accordance with their certifications under the ISO 14001 environmental management system standard as a means of guiding the facilities to go beyond compliance, where appropriate and feasible, as well as to achieve continuous environmental improvement.

8.5 OTHER

Beyond the nuclear-specific federal requirements described above, two pieces of provincial legislation apply in respect of the security personnel associated with OPG's nuclear generating facilities. These are the *Police Security Act* (Ontario) and the *Public Works Protection Act* (Ontario). Moreover, OPG in respect of its nuclear facilities is subject to generally applicable legislation and regulations in areas such as public access to information (Ontario or, indirectly as an affected third party, Canada), occupational health and safety (Ontario), employment standards (Ontario) and labour relations (Ontario). Each of these regulatory regimes is associated with resource requirements and attendant costs.

LIST OF ATTACHMENTS

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Payments to the Financial Corporation

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From February 19, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 27/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, $33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

   (i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.

2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.

2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

   i. return on rate base,

   ii. depreciation expense,

   iii. income and capital taxes, and

   iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to

reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

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Ontario

Electricity Generation Licence

EG-2003-0104

Ontario Power Generation Inc.

Valid Until
October 30, 2023

Mark C. Garner
Managing Director, Market Operations
Ontario Energy Board
Date of Issuance: October 31, 2003
Date of Amendment: April 25, 2005
Date of Amendment: April 10, 2006
Date of Amendment: September 12, 2006

Ontario Energy Board	Commission de l'Énergie de l'Ontario
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PART 1 GENERAL CONDITIONS .

1 Definitions

In this Licence:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

" **Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**"means: Ontario Power Generation Inc.;

"**regulation**" means a regulation made under the Act or the Electricity Act;

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in the Licence:

a) to generate electricity or provide ancillary services for sale through the IMO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;

b) to purchase electricity or ancillary services in the IMO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

c) to sell electricity or ancillary services through the IMO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

5.1 Where the IMO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IMO-controlled grid, for the Licensee to provide energy or ancillary services, the IMO may require the Licensee to enter into an agreement for the supply of energy or such services.

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

6 Restrictions on Certain Business Activities

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

7 Provision of Information to the Board

7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

7.2 Without limiting the generality of paragraph 7.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

8 Term of Licence

8.1 This Licence is effective on October 31, 2003 and shall expire on October 30, 2023. The term of this Licence may be extended by the Board.

9 Fees and Assessment

9.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

10 Communication

10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

10.2 All official communication relating to this Licence shall be in writing.

10.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

11 Copies of the Licence

11.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

PART 2 PRICE CAP AND REBATE

1. Definitions and Interpretation

In Parts 2 through 5 inclusive of these Licence Conditions:

"**Average Price**" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by summing the product of the Hourly Price multiplied by the Contract Weight for all hours of that Settlement Period;

"**Changes in Law**" means changes in law (including without limitation environmental laws, laws affecting OPGI's generation facilities, tax laws and the general laws affecting the regulation of electricity in Ontario), but excluding provincial tax laws and, for greater certainty, excluding changes in licence conditions and market rules;

"**Contract Required Quantity**" or "CRQ" means the quantity of energy upon which any Rebate is determined, in respect of a Settlement Period, as set forth in the Model Output Data and as may be modified pursuant hereto. Subject to such adjustments, the CRQ will equal the sum of all Hourly Quantities for all hours in a Settlement Period;

"**Contract Weight**" or "CW_h" means the weighting for each hour in a Settlement Period, h, that is used to calculate the Average Price. For any particular hour, the Contract Weight equals the Hourly Quantity for that hour divided by the CRQ for that Settlement Period;

"**Effective Control**" in respect of output means control over the timing, quantity and bidding into the Ontario market of such output;

"***Force Majeure* Adjustment**" or "FMA" means a reduction in the Rebate as a result of a *Force Majeure* Event;

"***Force Majeure* Event**" means an event defined in clause 2(c)(ii) of Part 2 below;

"***Force Majeure* Replacement Cost**" or "$FMRC_h$" means, for any particular hour in a Settlement Period, h, the predetermined net incremental replacement cost for each OPGI generation unit, as set forth in the Model Output Data that is used in determining the *Force Majeure* Adjustment, and as may be modified pursuant hereto. $FMRC_h$ may be constant in the Model Output Data over the hours in a month or other period;

"**Hourly Quantity**" or "Q_h" means, for any particular hour in a Settlement Period, h, the quantity of energy upon which the Contract Weight is established, as set forth in the Model Output Data. The sum of the Hourly Quantities for all hours in a Settlement Period equals the CRQ for that Settlement Period;

"**Hourly Price**" or "P_h" means, for any particular hour in a Settlement Period, h, the unconstrained spot price for energy for that hour expressed in a price in $ per MWh, as determined by the IMO pursuant to its market rules;

"**Hourly Reserve Capacity Price**" is the hourly market clearing price of reserve capacity;

"**Hourly Unit Quantity**," or "q^i_h" means, for any particular hour in a Settlement Period, h, the hourly quantity of energy associated with a particular OPGI generation unit, i, upon which the Hourly Quantity is established, as set forth in the Model Output Data. The sum of all Hourly Unit Quantities for all OPGI generation units in respect of an hour equals the Hourly Quantity for that hour;

"**Locational Spot Price**" means, for any particular hour in a Settlement Period, h, and any particular OPGI generation unit, the spot price for energy at such generation unit's interconnection, which will only apply if location-based marginal pricing is developed in Ontario;

"**Model Output Data**" means the data filed with the Board. The Model Output Data contains data, some of which is confidential, derived from a production cost model of the electricity market in Ontario and neighbouring regions under the assumption that OPGI is assumed to bid its generation units in a manner that achieves an average sales price of $ 38/MWh. The resulting CRQ, Q_h, and q^i_h data reflects 90 per cent of OPGI's predicted sales to Ontario customers;

"**OPGI**" means Ontario Power Generation Inc.

"**Potential *Force Majeure* Event**" means an event defined in clause 2(c)(i) of Part 2 below;

"**Price Cap**" or "CAP" means $38/MWh, which is the threshold used in calculating the Rebate;

"**Price Spike Adjustment**" or "PSA" means the reduction in the Rebate as a result of qualifying price spikes, as calculated pursuant hereto;

"**Prime Rate**" means the variable annual rate of interest, calculated on the basis of a calendar year, announced from time to time by the IMO's then principal Canadian banker as the reference rate of interest (commonly known as its prime rate) then in effect and used by such bank for determining interest rates on Canadian dollar denominated commercial loans made by it in Canada to customers of varying degrees of credit-worthiness;

"**Rebate**" or "R" means the amount OPGI must pay the IMO as a consequence of the Average Price in any Settlement Period exceeding the Price Cap, less any applicable adjustments;

"**Rebate Carryforward Adjustment**" or "RCA" means the adjustment in which negative Rebates from a Settlement Period are used to offset Rebates in subsequent Settlement Periods;

"**Reserve Capacity Ratio**" is a number greater than 1, such as 1.2, that is set by the IMO for the purposes of multiplying by the hourly demand to determine the reserve capacity target in such hour;

"**Settlement Period**" means each time period over which OPGI's compliance with the Price Cap shall be measured, which shall be over a 12 month period, except that (1) the first Settlement Period shall commence on the opening of the competitive electricity market and shall consist of the first full 12 calendar months plus the days, if any, in the first partial month; and (2) the last Settlement Period shall end on the termination of the provisions of Part 2, and therefore could be less than 12 full calendar months; and

"**Tier 1**" capacity means all nuclear and hydroelectric generation in Ontario and "**Tier 2**" capacity means that portion of Ontario's generation capacity, including inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. For such purposes, generation capacity shall be based upon the maximum continuous rating of a unit, inter-tie capacity shall be based on the average of summer and winter season Ontario transfer capacity, and demand-side bidding shall be based on the sum of the dispatchable and interruptible loads, all expressed in MW.

All dollar amounts referred to are expressed in Canadian dollars.

2. Determination of Rebate

OPGI shall pay a Rebate to the IMO in respect of each Settlement Period in which the Average Price (AP) exceeds the Price Cap (CAP). The amount of the Rebate shall be determined in accordance with the following formula:

R = [(AP - CAP) * CRQ] - (RCA + PSA + FMA)

If the calculated Rebate in respect of any Settlement Period is a negative number, then there shall be no Rebate, and the Rebate Carryforward Adjustment shall be changed as described herein.

(a) *Rebate Carryforward Adjustment*

Initially, the Rebate Carryforward Adjustment ("RCA") shall be zero. In any Settlement Period in respect of which the calculated Rebate is negative, the absolute value of that amount shall be the Rebate Carryforward Adjustment for the purposes of the next Settlement Period.

(b) *Price Spike Adjustment*

A Price Spike Adjustment (PSA) shall be calculated for all hours in a Settlement Period in which both (1) the Hourly Price (P_h) exceeds $125/MWh, and (2) OPGI's Generation for that hour is less than the Hourly Quantity (Q_h). The PSA for a Settlement Period shall equal the sum of the adjustments for each applicable hour, which shall be calculated pursuant to the following formula:

PSA = (P_h - $125/MWh) * ($Q_h$ – OPGI's Generation for that hour),

where OPGI's Generation for that hour = OPGI's energy generated from all sources in Ontario (metered as per IMO market rules) the output of which is Effectively Controlled by OPGI and which was included as OPGI energy generated in the Model Output Data, and includes the current power purchase agreement with Manitoba Hydro.

(c) *Force Majeure* Adjustment

(i) Potential *Force Majeure* Event

A Potential *Force Majeure* Event is any event consisting of any of the following conditions or events that results in the loss or failure of, or the inability to operate, in whole or in part, one or more generation units in Ontario the output of which is Effectively Controlled by OPGI and that, in each case, is beyond the reasonable control of OPGI and which is not a result of OPGI's failure to comply with pre-existing laws or licence conditions or market rules or to reasonably maintain or to use its best efforts to promptly repair any generation unit or units:

(A) acts of war, revolution, riot, sabotage, occupation or vandalism;

(B) earthquakes, tornadoes or severe storms;

(C) other acts of God;

(D) local, regional or national states of emergency;

(E) strikes or other labour disputes;

(F) other failure or damage to an OPGI generating facility, including failure or damage caused by construction defects, fire, or damage to necessary equipment and which is not a result of negligence in the maintenance or repair thereof;

(G) interruptions in the supply of fuel or other essential supplies (excluding variations in water supplies in the case of hydroelectric generation units);

(H) failure of transmission or distribution facilities in Ontario;

(I) other system emergencies in Ontario; and

(J) Changes in Law.

(ii) Definition of *Force Majeure* Event

A *Force Majeure* Event is either an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event.

An Isolated *Force Majeure* Event is that portion of any Potential *Force Majeure* Event that occurs after the Potential *Force Majeure* Event has caused a reduction in the energy actually generated by the applicable units greater than 250,000 MWh from the sum of such units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Event.

A Cumulative *Force Majeure* Event occurs in a Settlement Period when the cumulative reduction in that Settlement Period of energy actually generated by affected generation units in Ontario the output of which is Effectively Controlled by OPGI caused by Potential *Force Majeure* Events exceeds 500,000 MWh when compared to the sum of such affected units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Events. OPGI will, where applicable, designate within 15 days following the end of the applicable Settlement Period that portion of Potential *Force Majeure* Events that is in excess of 500,000 MWh and that qualifies as a Cumulative *Force Majeure* Event.

A Potential *Force Majeure* Event, or a portion of a Potential *Force Majeure* Event, that qualifies as both an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event may at the discretion of OPGI within 15 days following the end of the applicable Settlement Period be designated as either type of *Force Majeure* Event, but not as both, and, for greater certainty, a Potential *Force Majeure* Event designated as one type of *Force Majeure* Event by OPGI shall not be treated for purposes of determining whether the other type of *Force Majeure* Event has occurred.

(iii) *Force Majeure* Adjustment

The *Force Majeure* Adjustment (FMA) in respect of any Settlement Period shall be equal to the sum, for all generation units the output of which is Effectively Controlled by OPGI subject to *Force Majeure* Events, of the *Force Majeure* Replacement Cost ($FMRC_h$) in respect of each applicable unit for each hour during the effectiveness of each *Force Majeure* Event in respect of such unit during the Settlement Period, less any insurance or other recovery in respect of such loss or deemed loss.

The *Force Majeure* Adjustment in respect of any Settlement Period for each generation unit the output of which is Effectively Controlled by OPGI whose generation is reduced as a consequence of a *Force Majeure* Event shall be calculated pursuant to the following formula, prior to any recovery adjustment:

$$\sum_h [q^i_h \ * \ \mathbf{FMRCh} * ((\mathbf{Capacity} - \mathbf{Reduced\ Capacity}_h)/\mathbf{Capacity})]$$

where:
Capacity = the maximum continuous rating of the unit at the time of the *Force Majeure* Event (at normal head for hydroelectric generation units); and
Reduced Capacity$_h$ = the reduced capacity in an hour of the unit as a consequence of and during the effectiveness of the *Force Majeure* Event.

(iv) Adjustment to *Force Majeure* Replacement Cost

In the event that over 2,000 MW of OPGI generating capacity the output of which is Effectively Controlled by OPGI qualifies for a particular *Force Majeure* Event, OPGI shall have the right to petition the Board to increase the amount of the *Force Majeure* Replacement Cost in respect of one or more affected unit(s) in the applicable hours, which petition shall be granted if OPGI can demonstrate to the Board's satisfaction higher incremental replacement costs (net of any variable costs avoided as a consequence of the *Force Majeure* Event) than those set forth in the Model Output Data.

(v) Notice

OPGI shall promptly notify the IMO of any *Force Majeure* Event claimed by OPGI and shall provide the IMO with all information reasonably required to verify the *Force Majeure* Event and to calculate the *Force Majeure* Adjustment.

3. Conduct of OPGI

OPGI may engage in unilateral actions to attempt to maintain Hourly prices at levels that will result in the Average Price for a Settlement Period equaling the Price Cap, plus all adjustments provided for in Part 2, Section 2 above. In the event that unilateral actions taken by OPGI cause the Average Price to exceed such a level, the sole remedy shall be for OPGI to pay the Rebate as provided for in paragraph 2 of Part 2 above.

4. Reduction to CRQ and Q_h Upon Decontrol

(a) *Unadjusted Reductions*

Except as may be provided in (b) below, in the event that OPGI completes the transfer of Effective Control over the output of a generation unit, as determined by the Board under Part 3, then Q_h for each hour in respect of the current and any subsequent Settlement Period shall be reduced by 110 percent of the q^i_h of the transferred unit for each hour subsequent to the completion of the transfer. As a result, the CRQ in respect of each applicable Settlement Period shall be reduced by these reductions in Q_h.

(b) *Adjustment Necessitated by Environmental Laws*

In the event that OPGI transfers Effective Control over the output of a generation unit and the transferee, at the date of completion of the transfer, does not have and cannot reasonably obtain sufficient environmental emission permits or other environmental authorizations ("emission permits"), in respect of the applicable hours in the period commencing following the completion of the transfer of Effective Control (the "applicable hours"), to enable the unit's potential output during the applicable hours (the "transferred permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h of such unit (the "transferred output"), whether as the result of a change in environmental laws or otherwise, then:

(i) any adjustment to Q_h and CRQ otherwise provided for in (a) above will reduced by the proportion that the transferred permitted output is of the transferred output, subject to (ii) below;

(ii) in circumstances where OPGI's remaining emission permits following the transfer of Effective Control are not sufficient to enable its remaining output during the applicable hours (the "remaining permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h's of its remaining units, (the "remaining output"), then, in lieu of the adjustment provided for in (i) above, any adjustment to Q_h and CRQ otherwise provided for in (a) above will be multiplied by the result of the following formula, which if greater than 1.0 shall be deemed to be equal to 1.0:

(transferred permitted output/transferred output)/
(remaining permitted output/remaining output); and

(iii) where the transferee's emission permits are affected by more than one substance, then the resulting adjustment to Q_h and CRQ otherwise provided for in (i) or (ii) above will be that which operates to constrain the transferee's output.

5. Administration of Rebate

OPGI shall enter into and comply with a settlement agreement with the IMO consistent with the document attached as Schedule A and B to this licence.

6. Capacity Reserve Market

In the event that a capacity reserve market is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_h [CW_h * [P_h + (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]]$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraph 2(b) of Part 2 above:

PSA = [(P_h + Hourly Reserve Capacity Price * Reserve Capacity Ratio) - \$125/MWh] * (Q_h – OPGI's Generation for that hour);

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market introduced.

7. Location-Based Marginal Pricing

In the event that location-based marginal pricing is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$\textbf{AP} = \sum_{h,i} (\textbf{Locational Spot Price} * q^{i}_{h})/\textbf{CRQ}$$

(b) the Hourly Price, or P_h, for purposes of determining if a price spike has occurred and in order to calculate the Price Spike Adjustment in each applicable hour, shall be the average price of energy OPGI sells into the IMO spot market in that hour, which average price shall be determined by dividing OPGI's hourly spot market revenue in $ by the quantity (calculated in MWh) of OPGI's spot market sales; and

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the location-based marginal pricing introduced.

8. Capacity Reserve Market and Location-Based Marginal Pricing

In the event that both a capacity reserve market and location-based marginal pricing are developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definitions provided for in paragraphs 1, 6 or 7 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$\textbf{AP} = \sum_{h} [\textbf{CW}_h * (\textbf{Hourly Reserve Capacity Price} * \textbf{Reserve Capacity Ratio})]$$

$$+ \sum_{h,i} (\textbf{Locational Spot Price} * q^{i}_{h})/\textbf{CRQ}$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraphs 2(b) or 6 of Part 2 above:

PSA = [(Hourly Reserve Capacity Price * Reserve Capacity Ratio)
+ $\sum_i$ ((Locational Spot Price * q^i_h)/Q_h) - $125/MWh]

*** (Q^h – OPGI's Generation for that hour);**

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market or location-based marginal pricing introduced.

9. Additional Adjustment for Changes in Law

If one or more Changes in Law cause or are reasonably expected to cause a decrease in OPGI's net annual income equal to or greater than $60,000,000, then, rather than treating such Changes in Law as a *Force Majeure* Event for purposes of paragraph 2 above, OPGI may apply to the Board for a variation in the CRQ, Rebate, and/or the Price Cap methodology in respect of the Settlement Period in which the Change in Law occurs and all subsequent Settlement Periods the Change in Law is reasonably expected to affect in order to ensure that OPGI is not materially adversely affected as a result, taking into account all Changes in Law and whether the net effect of these Changes in Law have benefited or are reasonably likely to benefit OPGI during the same time period or any prior or subsequent time period.

10. Termination of Part 2

Beginning April 1, 2005 the OPG rebate calculation will be determined by the formula set out in Schedule B - Additional Terms and Conditions of Settlement Agreement Between IMO & OPG as amended from time to time.

PART 3 TRANSFER OF EFFECTIVE CONTROL

[Part 3 is revoked, effective December 7, 2005]

PART 4 INBOUND TRANSMISSION RIGHTS AND IMPORT LIMITS

1. Definitions and Interpretation

In this Part 4, "season" means the winter period (the "winter season") from and including November 1 until and including April 30 of the following year or the summer period (the "summer season") from and including May 1 until and including October 31 of the same year, as applicable.

2. Inter-tie and Import Limits

(a) OPGI shall not import energy into Ontario in excess of the energy import limits set forth in (b) below. In no event shall a purchase from the IMO spot market in Ontario be construed as an import of energy into Ontario for such purposes.

(b) The energy import limits referred to in (a) above are:

(i) 7.24 TWh during the winter season (increased to 7.28 TWh in a leap year); and

(ii) 6.58 TWh during the summer season;

all of which figures shall be increased, at the in service date of new or upgraded inter-tie facilities, by 35 percent times the number of hours in a season multiplied by any applicable net increase in inter-tie capacity in Ontario as determined by the IMO from that in effect on the date of the opening of the competitive electricity market. For such purposes, inter-tie capacity shall be based on the Ontario transfer capacity in the applicable season.

(c) The foregoing provisions of paragraph 2 shall not be required to be complied with by OPGI with the IMO's consent in an emergency situation.

3. Export Limits

Unless otherwise provided herein, none of the provisions of Parts 2 through 5 shall limit OPGI's ability to export energy from Ontario.

PART 5 MARKET BASED ANCILLARY SERVICES

(Note: Market based ancillary services are currently comprised of Operating Reserves only, but the principles outlined herein suggest a framework that could be used for other market based ancillary services.)

Unless the IMO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10-minute and 30-minute) exists, OPGI shall be required to comply with the following requirements:

(a) the price to be bid by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IMO, which bid cap will be designed, taking into account the relevant IMO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to bid the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(b) in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) in the event that either OPGI or the IMO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IMO shall negotiateamendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments,if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) pending reaching an agreement, or pending the resolution of any dispute, the IMO may at any time set the bid cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) if the IMO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the bid price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

PART 6 BRUCE DECONTROL RELATED CONDITIONS

1. The Licensee shall implement a Ring-Fence plan in accordance with the plans referred to in Section 8A of OPG's pre-filed evidence, and as detailed more fully in Interrogatory Responses I 6.5, and I 15.13 of RP-2002-0142, with the following exception:

   a) Only commercially sensitive information will be captured by the Ring-Fence plan. For clarity, this consists of Bruce Power outage information not already in the public domain and unit condition information only.

2. The Licensee shall conduct internal audits of the Ring-Fence plan every two calendar years. For clarity, the next internal audit will take place in 2007.

3. The Licensee must provide to the Board every year a self-certification statement signed by both the Chief Executive Officer and the Senior Regulatory Officer or other Senior Officer of OPG that the Ring-Fence plan methodology is operational for the activities that remain ring-fenced.

4. OPG shall make Status Reports to the Board within 30 days of:

   a. Any additional agreements entered into with BP LP;

   b. Any amendments, replacements or extensions of existing agreements with BP LP; and

   c. Expired agreements under the Bruce Transaction.

5. Prior to May 1st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Confidential Audit Report to the Board. For clarity, the next report will be filed on or before May 1, 2007. The report shall include:

   a. A review of the design, implementation, completeness and security of the Ring-Fence plan by OPG's internal audit group;

   b. A list of all the violations of the Ring-Fence plan with an explanation as to the type of violation, the employee's position and department or group, and whether the incident represents a repeat violation by a given employee;

   c. Recommendations regarding corrective action where the Ring-Fence plan has been violated;

d. A list of the number of employees that have moved outside the Ring-Fence to a new position in OPG (whether the position is permanent or temporary) The Report shall identify the old position and department or group that was in the Ring-Fence plan, and the new position and department or group in which the employee now works.

6. Prior to December 31st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Public Audit Report to the Board for the public record. The report shall include the above findings from the Confidential Audit Report, however, the report shall be redacted to remove personal information and any other information that the Board agrees may be redacted under its confidential filing guidelines. For clarity, the next report will be filed on or before December 31, 2007.

7. The Contract for Differences for Forced Outages agreement between OPG and BP LP shall not be renewed at its expiry on the second anniversary of Market Opening.

SCHEDULE A
TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IMO & OPGI

For these purposes, terms with initial capitals not otherwise defined herein shall have the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI or the IMO's Market Rules, as applicable.

OPGI will be required to rebate annually to the IMO. As soon as practicable and preferably within 15 days following the final settlement of transactions which occurred during each Settlement Period, the IMO shall calculate the Rebate and notify OPGI of such calculated Rebate.

If OPGI agrees with the IMO's calculation then, within 30 days of being notified, OPGI will be required to pay such Rebate, if any, to the IMO. If OPGI does not agree with the IMO's calculation and the parties can agree within a further 30 days on a revised Rebate, then, within 30 days of so agreeing, OPGI will be required to pay the agreed revised Rebate, if any, to the IMO. If OPGI does not agree with the IMO's calculation and the parties cannot agree on a revised Rebate within such further 30 day period, then the matter shall be finally determined by arbitration by the Dispute Resolution Panel of the IMO, and, within 30 days of such final determination, OPGI will be required to pay the finally determined Rebate, if any, to the IMO. The initially calculated, agreed revised, or finally determined Rebate, as applicable, shall be the Rebate in respect of such Settlement Period for all purposes hereof. Unless the Rebate is paid within 30 days of the IMO notifying OPGI, interest at the Prime Rate, calculated and accrued daily, from such 30th day until the date of payment to the IMO will in all cases be added to (and based upon) the final Rebate owing.

Following payment of the Rebate by OPGI to the IMO, the IMO shall pay or apply the Rebate as follows:

(a) Where the Rebate is $10 million or more, exclusive of any amounts representing interest or GST, the IMO shall pay the Rebate, including GST and interest, to all persons who were Market Participants in Ontario during the Settlement Period and who pursuant to the Market Rules had attributed to them during the Settlement Period an allocated quantity of energy withdrawn at a Delivery Point (the "Ontario Payees"). The IMO shall pay the Rebate to Ontario Payees by the next IMO Payment Date for the real-time market following the end of the month in which the payment from OPGI is received and the IMO shalldistribute payment of the Rebate to Ontario Payees in proportion to the allocated quantities of energy withdrawn at a Delivery Point which were attributed to each Ontario Payee during the Settlement Period. The IMO may, to the extent practicable, pay the Rebate to all or some Ontario Payees by applying a Rebate settlement credit to the Ontario Payees' applicable Settlement Statements; and

(b) Where the Rebate is less that $10 million, exclusive of any amounts representing interest or GST, the IMO shall retain and apply the Rebate, inclusive of any amounts representing interest or GST, to offset the IMO Administration Charge imposed on Market Participants in accordance with section 4.5, Chapter 9 of the Market Rules, during the period in which the first order of the OEB approving the IMO Administration Charge made,

(i) pursuant to subsection 19(2) of the Electricity Act, 1998, and

(ii) subsequent to the date on which payment of the Rebate is received by the IMO, is in effect.

Where paragraph (a) applies, if by the date upon which the IMO is required to pay the Rebate to Ontario Payees, the IMO cannot locate an Ontario Payee, or a successor or other representative of the said Ontario Payee to whom the IMO is permitted or required by law to pay the said Ontario Payee's share of the Rebate, the IMO shall retain the said Ontario Payee's share of the Rebate for a period of 90 days from the date upon which the Rebate is otherwise payable to all other Ontario Payees, and during this period the IMO will make commercially reasonable efforts to locate and payout the applicable share of the Rebate to the said Ontario Payee or his successor or other legal representative. If the IMO is unable to locate the said Ontario Payee or his successor or other legal representative within this 90 day period, the IMO shall retain the said Ontario Payee's share of the Rebate and apply it to the IMO Administration Charge in accordance with paragraph (b), as set out herein.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to OPGI or any other party.

The Settlement Agreement may also include the following terms:

- Definitions and Interpretation
- Notice by OPGI to IMO of Payment and Non-Payment
- Appropriate limitations of liability
- IMO shall recover its reasonable rebate administration expenses through its fees
- Appropriate indemnification provisions
- IMO to act on its own behalf and as agent for Ontario Metered Market Participants entitled to rebates to the extent of their interests, and such Metered Market Participants are entitled, provided that they give a satisfactory funded indemnity to the IMO, to enforce, by arbitration, the Settlement Agreement directly against OPGI if desired, with reasonable assistance to be provided by IMO at their expense
- IMO may assign agreement to a qualified replacement upon approval of OEB. No other assignments without consent of other party and OEB

- IMO may subcontract any duties required of it
- Fund transfer instructions, which may be changed on notice to OPGI by IMO
- Arbitration clause with Dispute Resolution Panel as arbitrator
- Recipient registrants responsible for all taxes, if any
- Any interest earned on funds by IMO shall be paid to recipient registrants similarly to other funds
- IMO not to be viewed as in conflict in any respect as a result of its participation in the Settlement Agreement
- IMO may hold funds on deposit with a Canadian financial institution or in short-term obligations of the federal or Ontario government or any Canadian financial institution
- IMO may, but shall not be obliged to, retain and refrain from distributing any funds in the event of any dispute, and may seek advice from the Dispute Resolution Panel
- Termination of agreement when OPGI Rebate obligations terminate and all funds distributed or applied. OPGI/IMO indemnification obligations and third party enforcement rights to survive termination, former indefinitely and latter for 2 years only
- IMO may rely on any document which it believes to be genuine and on the advice of counsel, if it acts in good faith
- IMO not responsible for any non-payment by OPGI
- Binding on successors and permitted assigns
- Notice clause
- Only may be amended in writing
- Governed by the laws of Ontario
- Counterparts clause
- Further assurances clause

SCHEDULE B
ADDITIONAL TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IMO & OPG

The following sets out the procedure for calculating, allocating and passing through the Market Power Mitigation Agreement (MPMA) Rebate. Where there is a conflict between Schedule A in the Minister's Directive dated March 24, 1999, as amended or replaced by a subsequent Ministerial Directive dated February 25, 2003 which relates to Order-in-Council 654/2003 (dated March 19, 2003), and subsequent Orders-in-Council including Order-in-Council No. 843/2003 (dated April 2, 2003), Order-In-Council No. 207/2005 (dated February 16, 2005), Order-in-Council No. 1909/2005 (dated December 7, 2005) and this Schedule B, then this Schedule B prevails.

For the First Settlement Period (May 1, 2002 to April 30, 2003)

1) The first MPMA Rebate is to be paid out for the 9-month period ending January 31, 2003. This is the amount, as calculated by the IMO and agreed to by OPG, that OPG is required to rebate for the nine month period, based on OPG's MPMA license conditions, less the interim payment already made by OPG of approximately $335 million and amounts relating to decontrol applications pending before the Ontario Energy Board. OPG is to pay this net amount to the IMO by May 9, 2003.

2) The second MPMA Rebate will cover the three-month period February 1, 2003 to April 30, 2003 inclusive. This is the amount, as calculated by the IMO and agreed to by OPG, that OPG is required to rebate for the three month period, based on OPG's license conditions, adjusted for any true-up required to ensure that the sum of the two rebates for the first settlement period, including the interim payment, is equal to OPG's full rebate requirements for the first Settlement Period under the OPG's MPMA license conditions. OPG is to pay this amount to the IMO by August 12, 2003.

3) The IMO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

4) The IMO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA rebate.

5) The IMO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the share of energy withdrawn during the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IMO will rely on the information reported by the distributors to the IMO as required under Appendix D. Once the IMO has received the information from the distributors and disbursed the first MPMA Rebate or the second MPMA Rebate in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

6) After making the payments set out in 3), 4), and 5), the IMO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the fixed price of 4.3 cents per kilowatt hour to consumers who are eligible to receive, are receiving or have received the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IMO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Settlement Periods (May 1, 2003 to January 31, 2005)

7) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005, OPG is to make quarterly MPMA Rebate payments to the IMO, consistent with OPG's MPMA license conditions, as calculated by the IMO and agreed to by OPG. The IMO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

8) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IMO as follows:

$$BPPR = [(WAP - CAP) \times 0.5 \times TAQEW]$$

Where:
"**Business Protection Plan Rebate**" or "**BPPR**" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the

Ontario Energy Board Act, 1998. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt- hour.

"**Weighted Average Price**" or "**WAP**" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IMO.

"**Total Allocated Quantity of Energy Withdrawn**" or "**TAQEW**" is the total electricity withdrawn from the IMO-controlled grid for use in Ontario during the Settlement Period.

9) The IMO will make quarterly MPMA payments to market participants based on the applicable Settlement Period to the end of the previous quarter, and taking into account all prior quarterly MPMA payments made with respect to the applicable Settlement Period. The IMO will adjust the payment for the final quarter of each Settlement Period to ensure that the sum of the quarterly MPMA payments for the applicable Settlement Period does not exceed the BPPR entitlement for the Settlement Period. If there is an overpayment of quarterly payments over a Settlement Period based on the BPPR entitlement for that Settlement Period, any such overpayment can be carried over to successive Settlement Periods to be offset against future payments.

10) The IMO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

11) The IMO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

12) The IMO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IMO will rely on the information reported by the distributors to the IMO as required under Appendix D. Once the IMO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to

correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

13) For the quarterly periods from May 1, 2003 to January 31, 2005, after making the payments set out in 10), 11), and 12), the IMO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act 1998* to consumers who are eligible to receive the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Payment for the Period (February 1, 2005 to March 31, 2005)

14) For the Payment for the Period from February 1, 2005 to March 31, 2005, OPG is to make an MPMA Rebate payment to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

15) For the Payment for the Period from February 1, 2005 to March 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$\text{BPPR} = [(\text{WAP} - \text{CAP}) \times 0.5 \times \text{TAQEW}]$$

Where:

"**Business Protection Plan Rebate**" or "**BPPR**" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt hour.

"**Weighted Average Price**" or "**WAP**" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.

"**Total Allocated Quantity of Energy Withdrawn**" or "**TAQEW**" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

16) The IESO will make the MPMA payment to market participants for the two month period ending March 31, 2005 taking into account all prior MPMA payments made in that Settlement Period.

17) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

18) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

19) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

20) After making the payments set out in 17), 18), and 19), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act 1998* to consumers who are eligible to receive the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

Replacement of the MPMA Rebate With A New Payment for the Period (April 1, 2005 to December 31, 2005)

21) For the Payment for the Period from April 1, 2005 to December 31, 2005, OPG is to make a single payment to the IESO, calculated as follows:

Payment = Sum over all hours [(HOEP - $47) x (ONPA (output) x 0.85)]

Where:
ONPA or OPG's Non-Prescribed Assets are those generation assets, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005.

22) For the Payment for the Period from April 1, 2005 to December 31, 2005 the single payment to market participants will be equal to the payment calculated in 21) above.

23) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

24) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

25) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices

established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

26) After making the payments set out in 23), 24), and 25), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

27) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

Replacement of the MPMA Rebate With A New Payment for the Period (January 1, 2006 to April 30, 2006)

28) For the Payment for the Period from January 1, 2006 to April 30, 2006, OPG is to make a single payment to the IESO, calculated as follows:

Payment = Sum over all hours [(HOEP - $47) x (ONPA (output) x 0.85)])] + [(PA (price) - $52) x (PA (amount))]]

Where:
ONPA or OPG's Non-Prescribed Assets are those generation assets, operated and controlled by Ontario Power Generation assets, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005 and volumes sold through the Pilot Auction administered by the

Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006, which includes a limited amount of output from OPG's non-prescribed assets, with sales to commence on April 1, 2006.

PA (amount) is the hourly volume in MWh of OPG non-prescribed assets output sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales commencing on April 1, 2006.

PA (price) is the weighted average auction price in $/ MWh realized in each hour of the Period for the output of the limited amount of OPG non-prescribed assets output volume sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

29) For the Payment for the Period from January 1, 2006 to April 30, 2006 the single payment to market participants will be equal to the payment calculated in 28) above.

30) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

31) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

32) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the

IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

33) After making the payments set out in 30), 31), and 32), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

34) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

OPG Rebate for the Period (May 1, 2006 to April 30, 2009)

35) For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly payments to the IESO, as calculated by the IESO and agreed to by OPG as follows:

Payment = Sum over all hours [(HOEP - ORL) x (ONPAO x 0.85 - PAA) + (PAP - PAORL) x PAA)]

Ontario Power Generation's quarterly payments will be based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This will continue until the final quarter ending April 30, 2009. For greater certainty, where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG to by the IESO and any such amount will be is carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation in service as of January 1, 2006, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA or incremental output from ONPA resulting from refurbishment or expansion is to be excluded from ONPAO.

Incremental Output is defined as:
generation output x (new total installed capacity - installed capacity as of January 1, 2006) / new total installed capacity.

ORL is the Ontario Power Generation Revenue limit. For the period May 1, 2006 to April 30, 2007 ORL is equal to $46/MWh. For the period May 1, 2007 to April 30, 2008 ORL is equal to $47/MWh. For the period May 1, 2008 to April 30, 2009 ORL is equal to $48/MWh.

PA is the Pilot Auction administered by the Ontario Power Authority in the **first half of 2006.**

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 PAORL is equal to $51/MWh.
For the period May 1, 2007 to April 30, 2008 PAORL is equal to $52/MWh.
For the period May 1, 2008 to April 30, 2009 PAORL is equal to $53/MWh.

PAP is the weighted average auction price in $/MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

36) For the Payment for the Period from May 1, 2006 to April 30, 2009 quarterly payments made by the IESO to market participants will be equal to the quarterly Payment calculated in 35) above. In the event of any quarterly Payment calculated in 35) above being negative, no quarterly payment will be made by the IESO to market participants.

37) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established

under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

38) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants.

39) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable quarter by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act 1998* for the Payment. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

40) After making the payments set out in 37), 38), and 39), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

41) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

Hydraulic Generation Facilities by River System - Owned and Operated

<u>Niagara River System</u>
Sir Adam Beck - No. 1
Sir Adam Beck - No. 2
Pumping Gen. Stn.
Ontario Power
DeCew Falls No. 1
DeCew Falls No. 2
<u>St. Lawrence River System</u>
Robert H. Saunders
Ottawa River
Otto Holden
Des Joachims
Chenaux
Chats Falls (Units 2,3,4,5)
<u>Madawaska River System</u>
Mountain Chute
Barrett Chute
Arnprior
Stewartville
Calabogie
<u>Trent River System</u>
Healey Falls
Ranney Falls
Meyersburg
Sidney
Hagues Reach
Seymour
Franford
Sills Island
<u>Montreal River System</u>
Lower Notch
<u>Mattagami River System</u>
Wawaitin
Sandy Falls
Lower Sturgeon
<u>Montreal River System</u>
Indian Chute
Hound Chute
<u>Matabitchuan River System</u>
Matabitchuan
South River
Elliott Chute
Bingham Chute
Nipissing
<u>Sturgeon River System</u>
Crystal Falls
<u>Wanapitei River System</u>
Stinson
Coniston
McVittie
<u>Nipigon River System</u>
Pine Portage
Cameron Falls
Alexander
<u>English River System</u>
Ear Falls
Manitou Falls
Caribou Falls
<u>Winnipeg River System</u>
Whitedog Falls
<u>Kaministikwia River System</u>
Silver Falls
Kakabeka Falls
<u>Aguasabon River System</u>
Aguasabon
<u>Mississippi River System</u>
High Falls
<u>Rideau River System</u>
Merrickville
<u>Otonabee River System</u>
Auburn
Lakefield
<u>Muskoka River System</u>
Ragged Rapids
Big Eddy
South Muskoka
South Falls
Trethewey Falls
Hanna Chute
<u>Beaver River System</u>
Eugenia Falls
<u>Severn River System</u>
Big Chute
<u>Abitibi River System</u>
Abitibi Canyon
Otter Rapids
<u>Mattagami River System</u>
Little Long
Harmon
Kipling
Smokey Falls

Hydraulic Facilities - Operated only
<u>St. Lawrence River System</u>
Chats Falls (Units 6,7,8,9)

Fossil Generation - Owned and Operated

Lakeview
Lambton
Nanticoke
Thunder Bay - Unit 1
Thunder Bay - Units 2, 3
Atikokan
Lennox

Nuclear Generation - Owned and Operated

Pickering A
Pickering B
Darlington

Wind Generation - Owned and Operated

BIC Wind Turbine
Pickering Wind Turbine

Nuclear Generation - Owned Only

Bruce A
Bruce B

APPENDIX D

CNSC LICENCES ISSUED TO OPG

A. Nuclear Power Reactor Operating Licence - (Class IA Nuclear Facilities)

1. PROL 04.05/2010, Pickering NGS A, June 30, 2010
2. PROL 08.13/2008, Pickering NGS B, June 30, 2008
3. PROL 13.16/2008, Darlington NGS & Tritium Removal Facility, February 29, 2008

B. Radioactive Waste Facility Operating Licence - (Class IB Nuclear Facilities)

1. WFOL-W4-350.02/2008, Pickering Waste Management Facility, March 31, 2008
2. WNSL-W1-320.00/ind., Radioactive Waste Operations Site 1 (RWOS 1), indefinite
3. WFOL-W4-314.00/2017, Western Waste Management Facility, May 31, 2017
4. WFCL-W4-355.00/2008, Darlington Used Fuel Dry Storage Facility Construction Licence, November 30, 2008

C. Heavy Water Plant Decommissioning Licence - (Class IB Nuclear Facilities)

1. HWDOL-01.00/2014, Bruce Heavy Water Plant, March 31, 2014

D. Nuclear Substance and Radiation Devices Licence – (Nuclear Substances, Prescribed Equipment and Prescribed Information)

1. 12861-1-10.2 (Industrial Radiography), March 31, 2010
2. 12861-2-10.10 (Consolidated Uses), March 31, 2010
3. 12861-10-11.0, Darlington Heavy Water Sales Facility, March 31, 2011
4. 12861-12-11.0, BHWP Heavy Water Storage Facility, August 31, 2011

E. Dosimetry Service Licence – (Dosimetry Services)

1. 12861-11-10.1, May 31, 2010

F. Class II Irradiator Operating Licence – (Class II Nuclear Facilities and Prescribed Equipment)

1. Licence 12861-13-10.2 (Servicing - Class II Prescribed Equipment (566)), April 30, 2010
2. Licence 12861-7-09.1 Operation of a Class II Calibration Facility, March 31, 2009

G. Licence to Transport

1. TL-S-12861-03-00/2006, Licence to Transport Category III Material in the Irradiated Material Transportation Package, May 31, 2008

H. Import Licence

1. IL-A1-4102.0/2011 (Pickering A & B and Darlington) - Contaminated laundry returning from UniTech after processing, January 31, 2011
2. EL-A1-4099.0/2008 (Pickering A & B) - Import of returning contaminated waste after segregation by UniTech for final disposition by OPG, February 29, 2008
3. IL-A1 & A3-4129.0/2008 (Pickering B) - Import of refurbished nuclear class primary coolant pump parts contaminated with trace amounts of nuclear substance 1- pump cover and 1 – pump impeller, May 31, 2008
4. IL-A1-4198.1/2008 (Western Waste Facility) - Import of processed and unprocessed radioactive waste of Canadian origin, October 31, 2008

I. Export Licence

1. EL-A1-17853.0/2007 (Pickering A & B) - Radioactive Waste sent to Diversified Scientific to be incinerated as a dedicated burn and all ash waste be returned to OPG for storage at the Western Waste Management Facility, Tiverton, ON, November 30, 2007
2. EL-A1-17910.0/2011 (Pickering A & B and Darlington) - Contaminated laundry shipped to UniTech Services, November 30, 2011
3. EL-A1-17893.0/2008 (Pickering A & B) - Pilot - contaminated waste segregation project with UniTech Services, February 29, 2008
4. EL-A1 & A3-18254.0/2008 (Pickering B) - Export of nuclear class primary coolant pump parts contaminated with trace amounts of nuclear substance – 1 pump cover and 1 pump impeller, May 31, 2008

STAKEHOLDER CONSULTATIONS

1.0 Purpose

The purpose of this evidence is to provide a description of the stakeholder consultations that OPG held on its application prior to filing it with the OEB.

2.0 Background

In advance of its application to the OEB for the payment amounts for its regulated facilities, OPG held stakeholder consultation sessions. The following provides an outline of the stakeholder consultation plan including the consultation goal, principles, objectives, process, participants, and participant funding.

2.1 Goal and Principles

The goal of the consultations was to share information about OPG's regulated facilities and to discuss issues related to the application for new payment amounts. In support of this goal, the following principles were applied to the stakeholder consultation:

- OPG entered into the consultation process in good faith with a view to facilitating and streamlining future OEB proceedings related to the application.
- OPG considered all stakeholder comments while retaining control over the process for developing its application.
- All consultations were carried out on a without-prejudice basis.
- A neutral third party facilitator documented and reported on the discussions.

2.2 Objectives

The main objectives of the consultation were to:

- Inform stakeholders about OPG's regulated facilities and its application for new payment amounts.
- Provide stakeholders with an opportunity to identify concerns regarding OPG's draft application.
- Assist OPG in identifying possible ways to respond throughout the process to the issues raised.

2.3 Consultation Process

OPG held two stakeholder consultation sessions on a non-confidential, without-prejudice basis. The first session, held on November 2, 2007, focused on the nuclear and hydroelectric businesses and the regulatory process. The second session, held on November 8, 2007, focused on rate base, cost of capital, compensation and benefits, corporate allocations and the design and determination of the payment amounts. A copy of each day's agenda is provided in Appendix A. Copies of the presentations provided to stakeholders and a list of the stakeholders that attended the sessions are posted on OPG's website at: http://www.opg.com/about/reg/stakeholder.asp.

Participants were invited from key stakeholder groups. Specifically, OPG invited active intervenors from previous energy proceedings, energy and environmental associations, major industrial customers, and transmitters. OPG contacted stakeholders who participated in the OEB consultation on the form of regulation of OPG (EB-2006-0064) and other stakeholders who it believed would have a material interest in the application. The stakeholder invitation letter and a list of the invited participants are provided in Appendix B. Funding was offered to participants who qualified for funding under the funding guidelines, which are provided in Appendix C. The funding guidelines were based upon the Ontario Energy Board's Practice Direction on Cost Awards (October 2005) document.

Mr. J. Todd of Elenchus Research Associates was retained to provide third party facilitation and reporting on the consultation sessions. The facilitation role included assistance in identifying issues for discussion, exploring stakeholder views, and documenting the sessions. Elenchus Research Associates prepared meeting notes that documented discussions and stakeholder comments and feedback received during this process. Participants were also asked to review a draft of the notes and identify any gaps or omissions. OPG posted the meeting notes at http://www.opg.com/about/reg/stakeholder.asp.

3.0 Aboriginal Information Plan

While it is not expected that OPG's application for payment amounts for its regulated facilities will impact aboriginal or treaty rights, OPG developed a plan to inform the Aboriginal communities located in proximity to Pickering Generating Station, Darlington Generating Station, Bruce Nuclear Waste Storage Facility, R.H. Saunders Generating Station and Sir Adam Beck Generating Station, of OPG's application.

OPG sent a letter to each Aboriginal community located near the facilities listed above informing them of OPG's application and offering to provide additional information if requested. A copy of the information letter and a list of Aboriginal community contact are provided in Appendix D. The Chiefs of Ontario was copied on all correspondence. To date, OPG has not received any responses or requests for further information.

Appendix A: Agendas for Stakeholder Sessions #1 and #2

Appendix B: Stakeholder Invitation Letter and List of the Invited Participants

Appendix C: Funding Guidelines

Appendix D: Aboriginal Information letter and Aboriginal Community Contact List

Stakeholder Meeting #1

OPG Regulated Facilities Payment Amounts

Metropolitan Hotel
Toronto Ballroom, 2nd Floor
108 Chestnut Street, Toronto

November 2, 2007

AGENDA		
Date / Time	**Topic**	**Presenter**
8:00 – 8:30	Arrival and Coffee	
8:30 – 8:40	Welcome and Introductions	Andrew Barrett VP, Regulatory Affairs and Corporate Strategy
8:40 – 8:50	Agenda and Facilitation	John Todd Elenchus Research Assoc.- Facilitator
8:50 – 9:30	Application Overview	Barb Reuber Director, Ontario Regulatory Affairs
9:30 –10:15	Hydroelectric Business Overview	John Murphy EVP, Hydro
10:15 – 10:30	Break	
10:30 – 11:15	Nuclear Business Overview	Tom Mitchell Chief Nuclear Officer
11:15 – 11:45	Production Forecast Hydroelectric Summary	Mario Mazza Director, Business Support and Regulatory Affairs
11:45 – 12:45	Lunch	
12:45 – 1:30	Hydroelectric OM&A Costs	Mario Mazza Director, Business Support and Regulatory Affairs
1:30 – 2:15	Nuclear Base OM&A Costs and Projects	Paul Pasquet Deputy Site VP, Pickering B
2:15 – 2:45	Nuclear Production Forecast	Mike Allen Director, Work Management Pickering B
2:45 – 3:00	Break	
3:00 – 5:00	Stakeholder Issues / Discussion/Wrap-up	Facilitator
5:00	Adjourn	

Stakeholder Meeting #2

OPG Regulated Facilities Payment Amounts

Metropolitan Hotel
Toronto Ballroom, 2nd Floor
108 Chestnut Street, Toronto

November 8, 2007

AGENDA		
Date / Time	**Topic**	**Presenter**
8:00 – 8:30	Arrival and Coffee	
8:30 – 8:45	Welcome and Agenda	John Todd Elenchus Research Assoc.- Facilitator
8:45 – 9:15	Compensation and Benefits	Lorraine Irvine VP, Compensation and Benefits
9:15 – 10:00	Corporate OM&A, Allocations, Depreciation, and Taxes	Robin Heard VP, Controller
10:00 – 10:15	Break	
10:15 – 11:00	Rate Base and Cost of Capital	Fred Long VP, Financial Planning
11:00 – 11:30	Design of Payment Amounts: Hydroelectric	Ken Lacivita Director, Trading & Origination
11:30 – 12:00	Design of Payment Amounts: Nuclear	David Halperin Director, Financial and Business Planning
12:00 – 1:00	Lunch	
1:00 – 1:45	Determination of Payment Amounts	David Halperin Director, Financial and Business Planning
1:45 – 2:15	Deferral and Variance Accounts	Andrew Barrett VP, Regulatory Affairs & Corporate Strategy
2:15 – 2:30	Break	
2:30 – 5:00	Stakeholder Discussion/Wrap-up	Facilitator
5:00	Adjourn	

October 31, 2007

OPG Stakeholder Consultation:
OEB Application for Payment Amounts for Regulated Facilities

Mailing List

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Mr. David Butters
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Ms. Svetlana Diomin
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Mr. Terry Rees
Executive Director
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Ms. Susan Frank
Vice President & Chief Regulatory Officer
Hydro One Networks Inc.
483 Bay Street, 8th Floor, South Tower
Toronto, Ontario M5G 2P5

Mr. Malcolm Jackson
President
Financial & Regulatory Consultants of Canada
Low Income Energy Network
194 Berkeley Street
Toronto, Ontario M5A 2X4

Mr. Allan Fogwill
Applications Director
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Mr. Geri Kamenz
President
Ontario Federation of Agriculture
100 Stone Road West
Guelph, Ontario N1G 5L3

Mr. Jack Gibbons
Pollution Probe Foundation
625 Church Street, Suite 402
Toronto, Ontario M4Y 2G1

Mr. Bob Menard
Staff Officer, President's Office
Power Workers' Union
244 Eglinton Avenue East
Toronto, Ontario M4P 1K2

Mr. Bob Williams
Co-ordinator
School Energy Coalition
Ontario Education Services Corp.
c/o Ontario Public School Boards' Association
439 University Avenue, 18th Floor
Toronto, Ontario M5G 1Y8

Mr. Dan McDermott
Chapter Director
Sierra Club of Canada (Ontario Chapter)
24 Mercer Street
Toronto, Ontario M4V 1H3

Mr. Matthew Kellway
Staff Officer
Society of Energy Professionals
425 Bloor Street East, Suite 300
Toronto, Ontario M4W 3R4

Mr. John Muir
Toronto Board of Trade
1 First Canadian Place, PO Box 60
Toronto, Ontario M5X 1C1

Mr. Lauri Gregg
Principal
LCG Energy Management Group
Toronto Board of Trade
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Mr. Norm Tulsiani
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Mr. Rob McLeese
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Ms. Sandy O'Connor
Eastern Region Director, Regulatory & Legal Affairs
TransAlta Energy Marketing Corporation
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Calgary, Alberta T2R 0G7

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Regulatory Affairs
TransCanada Energy Limited
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8th Floor
Toronto, Ontario M5E 1J4

Mr. Mike Packer
Director, Regulatory Affairs
Union Gas Limited
50 Keil Drive North
Chatham, Ontario N7M 5M1

Mr. Michael Buonaguro
Counsel
Vulnerable Energy Consumers Coalition
c/o Public Interest Advocacy Centre
34 King Street East, Suite 1102
Toronto, Ontario M5C 2X8

ONTARIOPOWER GENERATION

Andrew Barrett, P.Eng., MBA
Vice President

Regulatory Affairs & Corporate Strategy

700 University Avenue, H18 G1, Toronto, Ontario M5G 1X6

Tel: 416-592-4463 Fax: 416-592-8519
andrew.barrett@opg.com

October 11, 2007

VIA COURIER

Sample Stakeholder Invitation Letter

Dear Stakeholder:

Ontario Power Generation Stakeholder Consultation:
OEB Application for Payment Amounts for Regulated Facilities

In February 2005, the Ontario government announced a framework for regulating and pricing the output of OPG's nuclear and baseload hydroelectric generating facilities. As of April 1, 2008, the Ontario Energy Board (OEB) will have the authority to determine payment amounts for the output from OPG's regulated facilities. OPG is preparing an application to the OEB for the payment amounts for its regulated facilities. OPG is planning to file its application in November 2007.

In advance of this application, OPG is conducting stakeholder consultations. The purpose of this letter is to invite you to participate in the stakeholder consultation process.

The goal of the consultations is to share information about OPG's regulated facilities and to discuss issues related to the application for new payment amounts. The main objectives of the consultation are to:

- Inform stakeholders about the issues critical to OPG's regulated facilities and its application for new payment amounts;
- Provide a preview of the draft application;
- Provide stakeholders with an opportunity to identify concerns regarding OPG's draft application;
- Assist OPG in identifying possible ways to address the concerns of stakeholders.

OPG is contacting stakeholders who participated in the OEB consultation regarding regulation of OPG and other stakeholders who have a material interest in the application.

The stakeholder process will consist of three one day discussion sessions during October. The topics and dates for the three sessions are as follows:

Session 1 – October 30, 2007: OPG business strategy and key issues;
Session 2 – November 2, 2007: Nuclear and Regulated Hydroelectric costs and production;
Session 3 – November 8, 2007: Design and determination of payment amounts.

The first session is an education session about OPG and its regulated operations. It will be held on October 30, 2007 at the Metropolitan Hotel at 108 Chestnut Street in Toronto, from 8:30 AM to 4:30 p.m. and will cover such topics as:

- OPG's regulated facilities
- Application overview
- Financial summary
- Business strategy and key issues

The final agenda and presentation materials for each session will be forwarded to participants in advance of the sessions. In addition, all presentation materials will be posted on OPG's web-site.

OPG will provide funding for participation in the consultations to eligible participants. A copy of the funding guidelines is attached for your information.

If you have any questions or would like to discuss OPG's stakeholdering or application process, please contact OPG's Case Manager, Ms. Barbara Reuber at 416-592-5419. Please confirm your attendance for each session by contacting Debbie Curley by email at debbie.curley@opg.com or by phone at 416-592-2712 by October 15, 2007.

Sincerely,

Andrew Barrett
Vice President
Regulatory Affairs & Corporate Strategy

OPG Stakeholder Consultation
Application for Payment Amounts for Regulated Facilities

Participant Funding Guidelines

To facilitate dialogue with its stakeholders, Ontario Power Generation (OPG) will provide funding to assist qualifying stakeholders to participate in its stakeholder consultation process related to its application to the Ontario Energy Board (OEB) for payment amounts for regulated facilities. The funding criteria that will be used are based on the OEB's most recent Practice Direction on Cost Awards. The following provides eligibility guidelines and a description of the funding process.

Eligibility

- The determination of whether a party is eligible for funding will be at the sole discretion of OPG.
- Funding is limited to not-for-profit organizations whose interests are affected by the application such as public interest organizations and environmental organizations.
- Individuals and organizations with a direct commercial or business interest in the application are not eligible for funding. This includes, but may not be limited to, transmitters, wholesalers, generators, distributors, retailers and marketers, or organizations representing these interests.
- Municipal or provincial government staff or representatives are not eligible for funding.
- Parties with similar interests are encouraged to combine their participation.
- Funding will be provided only to stakeholders participating in the discussion sessions.

Process for Funding and Eligible expenses

- To allow timely processing of requests, it is suggested that stakeholders seeking funding apply to OPG at least 7 days prior to the first session. Stakeholders should indicate in writing that they will be participating and include a statement justifying their eligibility.

  Parties should submit their request for financial support to:
  Ms. Barbara Reuber, Case Manager
  Ontario Power Generation
  700 University Ave. H18-G2,
  Toronto, ON M5G 1X6
  Fax: 416-592-8519

  OPG will notify the party prior to the session if their funding application is accepted.
- Funding will be provided for meeting preparation and attendance for one person based on rates outlined in the OEB's Cost Award Tariff.
- Preparation time is not to exceed an amount equal to the meeting time. Preparation time is only allowed if the stakeholder attends the session.
- Out of pocket travel expenses will be allowed including reasonable meals and accommodation only if the participant's place of business is greater than 100 km from the meeting site. Receipts must be submitted for all meals, accommodations and travel with the exception of mileage for personal automobile.
- Reasonable disbursements, such as postage, photocopying, etc., are eligible expenses.
- Eligible participants must submit an OPG disbursement claim sheet form complete with receipts, no later than 30 days after the final session.

Aboriginal Community Contact List

First Nations and Aboriginal organizations whom may have a current and/or historic interest in the areas around the Pickering and Darlington Nuclear facilities, the Beck and Saunders GS areas, and in the areas around the Bruce NGS include:

- Chief James Marsden
  Alderville First Nation
  PO Box 46, R.R. #4,
  Roseneath, ON K0K 2X0

- Chief Donna Big Canoe
  Chippewas of Georgina Island First Nation
  R.R. 2, PO Box 12,
  Sutton West, ON L0E 1R0

- Chief Keith Knott
  Curve Lake First Nation
  22 Winookeeda Road
  Curve Lake, ON K0L 1R0

- Chief Laurie Carr
  Hiawatha First Nation
  RR 2, 123 Paudash Street,
  Keene, ON K0L 2G0

- Chief Tracy Gauthier
  Mississauga's of Scugog Island First Nation
  22521 Island Road,
  Port Perry, ON L9L 1B6

- Chief Bryan LaForme
  Mississaugas of the New Credit
  R. R. #6, 2789 Mississauga Rd.
  Hagersville, ON NOA 1HO

- Mr. Tony Belcourt
  President
  Métis Nation of Ontario
  500 Old St. Patrick St
  Ottawa, ON, K1N 9G4

- Chief Kris Nahrgang
  Kawartha Nishnawbe First Nation
  Box 1432
  Lakefield, ON, K0L 2H0

- Mr. Michael McGuire
  President
  Ontario Métis Aboriginal Association
  452 Albert Street. 2nd Floor
  Sault Ste. Marie, ON P6A 2J8

- Mr. Rob Pilon,
  President
  The Oshawa Métis Council
  1288 Ritson Road North
  Suite # 356
  Oshawa , ON L1G 8B2

- Grand Chief Max "One-Onti" Gros-Louis
  Huron Wendat First Nation
  255 Place Chef Michel Laveau
  Wendake, Quebec G0A 4V0

- Chief Ralph Akiwenzie
  Chippewas of Nawash Unceded First Nation
  R.R. 5,
  Wiarton, ON N0H 2T0

- Chief Randall Kahgee Jr.
  Saugeen First Nations
  R.R. #1
  Southampton, ON N0H 2L0

- Chief Dave General
  Six Nations of the Grand River
  P.O. Box 5000
  Ohsweken, ON NOA 1M0

- Grand Chief Timothy Thompson
  Mohawks of Akwesasne
  PO BOX 579,
  Cornwall, ON K6H 5T3

A copy of the information letter will be provided to the Chiefs of Ontario.

- Ms. Lori Jacobs
  Executive Director
  Chiefs of Ontario
  111 Peter Street, Suite 804
  Toronto, ON M5V 2H1

ONTARIOPOWER GENERATION

Andrew Barrett, P.Eng., MBA
Vice President

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andrew.barrett@opg.com

Filed: 2007-11-30
EB-2007-0905
Exhibit A1-7-1
Appendix D
(Aboriginal Information Letter)

October 23, 2007

Sample Letter to the Aboriginal Community

Dear Chief,

Payment Amounts for OPG's Regulated Facilities

In February 2005, the Ontario government announced a framework for regulating and pricing the output of OPG's nuclear and baseload hydroelectric generating facilities. As of April 1, 2008, the Ontario Energy Board (OEB) will have the authority to determine payment amounts for the output from these facilities. Accordingly, OPG is preparing an application to the OEB for an order approving payment amounts for its regulated hydroelectric and nuclear facilities.

The regulated hydroelectric facilities are:

- Sir Adam Beck I,
- Sir Adam Beck II,
- Sir Adam Beck Pump Generating Station,
- De Cew Falls I,
- De Cew Falls II, and
- R.H. Saunders.

The nuclear generating facilities are:

- Pickering A,
- Pickering B, and
- Darlington.

OPG plans to file its application in late November 2007. The payment amounts set by the Ontario Energy Board must be sufficient to cover the cost of owning, operating, maintaining and developing the regulated facilities so that they can continue to fulfill their essential role in Ontario's electricity system and provide the greatest benefit to the people of Ontario. The current payment amounts are established by regulation at \$33/megawatt hour for the output of the regulated hydroelectric facilities and \$49.50/ megawatt hour for the output of the nuclear facilities.

OPG's application to the OEB is concerned with payment amounts for OPG's regulated facilities only. Any ongoing consultation in relation to other specific projects related to the above-noted stations will continue in accordance with our legal obligations.

As these regulated facilities may be near your community, OPG would be pleased to provide you with further information with respect to the OEB application upon request. If you have any concerns associated with the application or perceive any potential impact on your aboriginal or treaty rights, an OPG representative would be happy to meet with you to discuss them. If you have any questions or concerns, please contact OPG's Case Manager, Ms. Barbara Reuber at 416-592-5419 by November 9, 2007.

Sincerely,

Andrew Barrett
Vice President
Regulatory Affairs & Corporate Strategy

cc: Chiefs of Ontario

PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

To be filed behind this tab as and when Procedural Orders, Correspondence and Notices are filed.

WITNESS PANELS AND RESPONSIBILITIES

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories		
Rate Base/ Cost Of Debt • Rate base • Cost of debt • Summary of capitalization and cost of capital • Business planning process	David Halperin Fred Long Colleen Sidford	Ex. A1-T4-S1 Ex. A2-T2-S1 (except Section 4.1) Ex. A2-T3-S1 Exhibit B (all) Exhibit C (all, except Ex. C2-T1-S1)	Issue 1.1 Issues 2.1, 2.2, 2.3, 2.4	L-1-3 L-1-17 L-1-113 L-1-120 L-2-3 L-2-10 L-2-11 L-2-12 L-2-13 L-2-59 L-3-1 L-3-2 L-3-3 L-3-4	L-3-5 L-3-6 L-3-52 L-3-53[1] L-3-54[1] L-3-55 L-4-2[1,2] L-4-3 L-6-17 L-6-18 L-6-19 L-6-21 L-6-27[2] L-12-6	L-12-7 L-12-43[2] L-12-59 L-12-60 L-12-61 L-14-45[1] L-14-48 L-14-49 L-14-50[2] L-14-53[1,2] L-14-75 L-14-76 L-14-94[2] L-16-01
Regulated Hydroelectric • Hydroelectric OM&A • Hydroelectric OM&A and capital projects • Hydroelectric production forecast	Joan Frain Don Gagnon Mario Mazza Mark Shea	Ex. A1-T4-S2 Ex. A1-T6-S1 Section 7.0 Ex. D1-T1-S1 Ex. D1-T1-S2 Ex. E1-T1-S1 Ex. E1-T1-S2 Ex. F1-T1-S1	As they relate to regulated hydroelectric facilities: Issues 3.1, 3.2, 3.3, 3.4, 3.5 Issues 4.1, 4.2	L-1-14 L-1-16 L-1-21 L-1-22 L-1-23 L-1-24 L-1-36[2] L-1-40[2]	L-3-66 L-3-67 L-3-69 L-3-70 L-3-71 L-4-2[1,2] L-4-5 L-6-3	L-14-78 L-14-79 L-14-84 L-14-85 L-14-86 L-14-87 L-14-88 L-14-89

[1] Interrogatory response assignment has changed from that indicated on the bottom of the document with the response. Please use this table to determine the assignment of the interrogatory response to witness panels.
[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories
		Ex. F1-T2-S1 Ex. F1-T2-S2 Ex. F1-T3-S1 Ex. F1-T3-S2 Ex. F1-T3-S3 Ex. F1-T4-S1 Ex. F1-T4-S2 Ex. F1-T5-S1	Issue 5.1, 5.3, 5.9	L-2-1[2] L-2-17[2] L-2-18 L-2-19 L-2-24 L-2-26 L-2-27 L-2-28[2] L-2-50[2] L-2-61 L-3-54[2] L-3-60[2] L-6-4 L-6-23[2] L-6-38 L-6-39 L-6-40 L-6-41 L-6-42[2] L-6-43 L-13-1[2] L-14-47[2] L-14-50[2] L-14-53[2] L-14-90 L-14-91 L-14-92 L-14-93 L-16-3 L-16-4 L-16-8 L-16-9 L-16-10 L-16-11 L-16-12
Regulated Hydroelectric Other Revenues • Revenues from segregated mode of operation, water transactions, congestion management settlement credits and ancillary services	Joan Frain Don Gagnon Ken Lacivita Mark Shea	Ex. G1-T1-S1 Ex. G1-T1-S2	Issues 6.1, 6.2 Issue 6.4 (as it relates to regulated hydroelectric facilities)	L-1-67 L-1-68 L-1-69 L-1-99 L-1-103 L-1-104 L-1-105 L-1-106 L-1-107 L-2-53 L-2-54 L-3-94 L-3-95 L-3-96 L-14-80 L-14-81
Nuclear Base OM&A and Fuels • Nuclear base OM&A expense • Nuclear fuel expense	Rob Boguski John Mauti Paul Pasquet	Ex. A1-T4-S3 Ex. A1-T6-S1 section 8 (except Section 8.3) Ex. F2-T1-S1 Ex. F2-T2-S1 Ex. F2-T2-S2	As they relate to nuclear facilities: Issues 5.1, 5.3, 5.7, 5.9	L-1-34 L-1-35[2] L-1-38 L-1-39 L-1-40[2] L-1-41 L-2-43 L-2-44 L-2-45 L-2-46 L-2-47 L-2-51 L-14-6[2] L-14-11[2] L-14-12 L-14-13 L-14-14 L-14-15

[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories		
	Bill Robinson	Ex. F2-T5-S1 Ex. F2-T5-S2 Ex. F2-T6-S1		L-1-42 L-1-62 L-1-63 L-1-64 L-1-65 L-1-66 L-2-30 L-2-31 L-2-32 L-2-33 L-2-34 L-2-35 L-2-37 L-2-38 L-2-39 L-2-40 L-2-41	L-2-52 L-3-50 L-3-54[2] L-3-72 L-3-73 L-3-74 L-3-75 L-3-78 L-4-2[1,2] L-6-36 L-6-37 L-6-42[2] L-7-1 L-7-2 L-7-3 L-7-4 L-13-1[2]	L-14-16 L-14-18[2] L-14-19 L-14-20 L-14-21 L-14-22 L-14-23 L-14-24 L-14-32 L-14-33 L-14-34 L-14-35 L-14-38[2] L-14-53[2] L-16-16 L-16-17
Nuclear Production Forecast and Outage OM&A • Nuclear outage OM&A expense • Nuclear production forecast	Mike Allen Vince Gonsalves Rob Latimer Dana Letts	Ex. E2-T1-S1 Ex. E2-T1-S2 Ex. F2-T4-S1 Ex. F2-T4-S2	Issue 4.1 (as it relates to nuclear facilities) Issue 4.2 (as it relates to nuclear facilities) Issue 5.8	L-1-26 L-1-27 L-1-28[2] L-1-29 L-1-30 L-1-31 L-1-32 L-1-33	L-2-29 L-2-48 L-2-49 L-2-50[2] L-3-68 L-3-76 L-6-29 L-6-30	L-6-32 L-6-33 L-6-34 L-12-5 L-12-52 L-14-6[2] L-14-30 L-14-31

[1] Interrogatory response assignment has changed from that indicated on the bottom of the document with the response. Please use this table to determine the assignment of the interrogatory response to witness panels.
[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories
	Mike McFarlane			L-2-28[2] L-6-31
Nuclear Projects • Nuclear OM&A and capital projects • Nuclear refurbishment and new nuclear build	Mark Arnone Randy Leavitt Craig Sellers Laurie Swami	Ex. D2-T1-S1 Ex. D2-T1-S2 Ex. D2-T1-S3 Ex. F2-T3-S1 Ex. F2-T3-S2 Ex. F2-T3-S3	As they relate to nuclear facilities: Issues 3.1, 3.2, 3.3, 3.4, 3.5	L-1-15 L-1-47[2] L-2-1[2] L-2-16 L-2-17[2] L-2-20 L-2-21 L-2-22 L-2-23 L-2-36 L-2-42 L-3-60[2] L-6-1 L-6-2 L-6-23[2] L-6-25 L-6-27[2] L-6-28 L-7-5 L-14-6[2] L-14-7 L-14-8 L-14-10 L-14-11[2] L-14-25 L-14-26 L-14-27 L-14-28 L-14-47[2]
Nuclear Non-Energy Revenues • Revenues from heavy water, tritium and radioisotope sales and nuclear inspection and maintenance services • Costs related to the Bruce Nuclear Generating Stations • Revenues and costs related to lease of Bruce nuclear facilities	Mario Cornacchia Dennis Dodo Fred Long Bob Morrison	Ex. G2-T1-S1 Ex. G2-T1-S2 Ex. G2-T2-S1	Issues 6.3, 6.5 Issue 6.4 (as it relates to nuclear facilities)	L-1-70 L-1-71 L-6-15

[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories		
Nuclear Waste Management and Decommissioning • Revenue requirement treatment of liabilities for nuclear waste management and decommissioning	Neil Brydon Angelo Castellan Fred Long	Exhibit H (all) Ex. A1-T6-S1 Section 8.3	Issue 7.1	L-1-72 L-1-73 L-1-74 L-1-75 L-1-76 L-1-77	L-1-78 L-1-79 L-1-80 L-1-81 L-1-82 L-1-83	L-1-84 L-2-55 L-2-56 L-2-57 L-2-58 L-6-6
Corporate And Other Operating Costs • Corporate OM&A and centrally-held costs allocated to regulated facilities • Corporate capital projects • Asset service fee • Cost allocation methodology • Compensation and benefits • Depreciation expense • Tax expense	Neil Brydon Robin Heard Lorraine Irvine Tom Staines	Ex. A2-T1-S1 Ex. A2-T2-S1 section 4.1 Ex. D3-T1-S1 Ex. D3-T1-S2 Ex. F3-T1-S1 Ex. F3-T1-S2 Ex. F3-T2-S1 Ex. F3-T2-S2 Ex. F3-T3-S1 Ex. F3-T3-S2 Ex. F3-T4-S1 Ex. F3-T5-S1 Ex. F3-T5-S2 Ex. F4-T1-S1 Ex. F4-T2-S1	Issue 3.5 (as it relates to corporate projects) Issue 3.6 Issues 5.2, 5.4, 5.5, 5.6 Issue 5.3 (with the exception of regulated hydroelectric and nuclear FTEs) Issue 5.9 (as it relates to corporate OM&A purchased services) Issues 10.1, 10.2	L-1-18 L-1-19 L-1-20 L-1-35[2] L-1-36[2] L-1-37 L-1-43 L-1-44 L-1-45 L-1-46 L-1-47[2] L-1-48 L-1-49 L-1-50 L-1-51 L-1-52 L-1-53	L-3-63 L-3-79 L-3-80 L-3-81 L-3-82 L-3-83 L-3-84 L-3-85 L-3-86 L-3-87 L-3-88 L-3-89 L-3-90 L-3-91 L-6-5 L-6-7 L-6-8	L-14-43 L-14-44 L-14-46 L-14-50[2] L-14-51 L-14-52 L-14-53[1,2] L-14-54 L-14-55 L-14-56 L-14-57 L-14-58 L-14-59 L-14-60 L-14-61 L-14-62 L-14-63

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[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories
				L-1-54 L-1-55 L-1-56 L-1-57 L-1-58 L-1-59 L-1-61 L-1-114 L-1-115 L-1-116 L-1-117 L-1-118 L-1-121 L-1-122 L-2-1[2] L-3-51 L-3-60[2] L-3-62 L-6-9 L-6-10 L-6-11 L-6-12 L-6-13 L-6-14 L-6-16 L-6-24 L-6-42[2] L-13-1[2] L-14-17 L-14-18 L-14-36 L-14-37 L-14-38[2] L-14-39 L-14-41 L-14-42 L-14-64 L-14-65 L-14-66 L-14-67 L-14-68 L-14-69 L-14-70 L-14-71 L-14-72 L-14-73 L-14-77 L-14-94[2] L-16-2 L-16-5 L-16-6 L-16-7 L-16-15
Cost Of Capital • Opinion on capital structure and fair return on equity	Kathleen McShane Foster Associates, Inc.	Ex. C2-T1-S1	Issues 2.1, 2.2, 2.3, 2.5	L-1-2 L-1-4 L-1-5 L-1-6 L-1-7 L-1-8 L-1-9 L-3-31 L-3-32 L-3-33 L-3-34 L-3-35 L-3-36 L-3-37 L-12-24 L-12-25 L-12-26 L-12-27 L-12-28 L-12-29 L-12-30

[2] Interrogatory response is assigned to multiple panels.

[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories
				L-1-10 L-1-11 L-1-13 L-2-2 L-2-15 L-3-7 L-3-8 L-3-9 L-3-10 L-3-11 L-3-12 L-3-13 L-3-14 L-3-15 L-3-16 L-3-17 L-3-18 L-3-19 L-3-20 L-3-21 L-3-22 L-3-23 L-3-24 L-3-25 L-3-26 L-3-27 L-3-28 L-3-29 L-3-30 L-3-38 L-3-39 L-3-40 L-3-41 L-3-42 L-3-43 L-3-44 L-3-45 L-6-20 L-6-22 L-12-1 L-12-2 L-12-3 L-12-4 L-12-9 L-12-10 L-12-11 L-12-12 L-12-13 L-12-14 L-12-15 L-12-16 L-12-17 L-12-18 L-12-19 L-12-20 L-12-21 L-12-22 L-12-23 L-12-31 L-12-32 L-12-33 L-12-34 L-12-35 L-12-36 L-12-37 L-12-38 L-12-39 L-12-40 L-12-41 L-12-42 L-12-43[2] L-12-44 L-12-45 L-12-46 L-12-47 L-12-48 L-12-49 L-12-50 L-12-51 L-12-53 L-12-54 L-12-55 L-12-56 L-12-57 L-12-58 L-14-74

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories
Variance/Deferral Accounts • Clearance of existing deferral and variance accounts • Establishment of new and continuation of existing variance and deferral accounts	Andrew Barrett Joan Frain Lubna Ladak John Mauti	Exhibit J (all)	Issue 2.5 Issues 9.1, 9.2, 9.3, 9.4, 9.5, 9.6, 9.7	L-1-1 L-1-25 L-1-100 L-1-101 L-1-102 L-1-108 L-1-109 L-1-110 L-1-111 L-1-112 L-2-62 L-2-63 L-3-93 L-3-97 L-3-98 L-14-1 L-14-2 L-14-3 L-14-4 L-14-50[2]

[2] Interrogatory response is assigned to multiple panels.

Panel	Witnesses	Pre-filed Evidence	Issues	Interrogatories
Payment Amounts • Hydroelectric incentive mechanism • Nuclear fixed/ variable payment amount design • Summary of revenue requirements and revenue deficiency • Mitigation of payment amounts • Consumer impact • Implementation • Response to Methodology Report	Andrew Barrett David Halperin Ken Lacivita	Ex A1-T11-S1 Exhibit I (all) Exhibit K (all)	Issues 8.1, 8.2 Issues 10.2, 10.3	L-1-12 L-1-60[1] L-1-85 L-1-86 L-1-87 L-1-88 L-1-89 L-1-90 L-1-91 L-1-92 L-1-93 L-1-94 L-1-95 L-1-96 L-1-97 L-1-98 L-1-119 L-1-123 L-2-4 L-2-5 L-2-6 L-2-7 L-2-8 L-2-9 L-2-14 L-2-25 L-2-60 L-3-46 L-3-47 L-3-48 L-3-49 L-3-56 L-3-57 L-3-58 L-3-59 L-3-61 L-3-64 L-3-65 L-3-77 L-3-92 L-3-99 L-4-1 L-4-4 L-6-26 L-6-35 L-12-8 L-13-2 L-14-5 L-14-9 L-14-29 L-14-40[1] L-14-82 L-14-83 L-16-13 L-16-14

[1] Interrogatory response assignment has changed from that indicated on the bottom of the document with the response. Please use this table to determine the assignment of the interrogatory response to witness panels.

CURRICULUM VITAE OF
MICHAEL ALLEN

DIRECTOR, WORK MANAGEMENT

RESPONSIBILITIES:

As Director, Work Management at Pickering B, Mr. Allen's responsibilities include:
- All outage and on-line work management for four 520 megawatt units.
- Directing the work planning and control systems for the station, including scoping, planning, scheduling and monitoring of work activities.
- Directing strategic and tactical planning, providing input to the business planning process.

EDUCATION:

Bachelor of Physics, Northwestern University, Evanston, IL
Nuclear Engineer Officer, US Navy, Groton, CT
SRO License, North Anna Power Station, Mineral, VA
Senior Nuclear Plant Management Course, INPO Centre, Atlanta, GA

EXPERIENCE:

2003 - Present	Ontario Power Generation Inc.
2006 - Present	Director, Work Management
2003 - 2006	Manager, Maintenance
1999 - 2003	American Electric Power, D. C. Cook Nuclear Plant
2002 - 2003	Maintenance Manager
2000 - 2002	Outage Manager
1999 - 2000	SGRP Production Manager
1996 - 1999	Florida Power and Light, St. Lucie Nuclear Plant
1998 - 1999	Operations Manager
1996 - 1998	Training Manager
1985 - 1996	Virginia Power, North Anna Power Station
1989 - 1996	Supervisor Operations Training
1985 - 1989	Lead Instructor
1984 - 1985	Jersey Central Power and Light, Oyster Creek Nuclear Generating Station
1984 - 1985	Operations Engineer
1979 -1984	U.S. Navy Nuclear Power Program
1979 - 1984	Officer/Qualified Submarine Officer and Nuclear Engineer

CURRICULUM VITAE OF
MARK ARNONE

DIRECTOR, PROJECTS AND MODIFICATIONS

RESPONSIBILITIES:

As Director, Projects and Modifications for OPG Nuclear, Mr. Arnone's responsibilities include:

- Deliver major nuclear projects associated with the operating nuclear units. This includes design, project management, estimating, contract management, quality assurance and field execution.
- Ensure effective policies and procedures are in place for nuclear project management.
- Contract and oversee all Building Trades Union Contractors used for the operating units.

EDUCATION:

Lakehead University (1986) - Bachelor of Engineering, Mechanical

EXPERIENCE:

1990 – Present	Ontario Power Generation Inc.
2002 – Present	Director, Projects and Modifications
2000 – 2002	Manager, Project Management Office, Integrated Improvement Program
1997 – 2000	Section Manager, Pickering B Projects
1991 – 1997	Project Engineer, Pickering B Projects
1990 – 1991	System Engineer, Pickering B
1988 – 1990	Project Engineer, Canada Wire and Cable
1986 – 1988	Project Engineer, Lovat Tunnel Equipment

MEMBERSHIPS:

Professional Engineers Ontario (since December 1988)
Construction Industry Institute

CURRICULUM VITAE OF ANDREW BARRETT

VICE PRESIDENT, REGULATORY AFFAIRS AND CORPORATE STRATEGY

RESPONSIBILITIES:

As Vice President, Regulatory Affairs, and Corporate Strategy, Mr. Barrett's responsibilities include:

- The development and execution of OPG's regulatory strategy.
- Interactions with economic regulators and reliability organisations in Canada and the United States. These include the Ontario Energy Board, the Market Surveillance Panel, the National Energy Board, the Independent Electricity System Operator, and the Ontario Power Authority in Canada. In the United States, Federal Energy Regulatory Commission and the North American Electric Reliability Council.

EDUCATION:

McMaster University, 1995 - MBA (Finance/Accounting)
University of Waterloo, 1986 - Bachelor of Applied Sciences (Civil Engineering)

EXPERIENCE:

1998 - Present	Ontario Power Generation Inc., Ontario Hydro
2004 - Present	Vice President, Regulatory Affairs and Corporate Strategy
1998 - 2002	Manager, Canadian Regulatory Affairs/ Senior Advisor, Regulatory Affairs
1993 - 1998	Ontario Energy Board, Manager Applications / Monitoring

MEMBERSHIPS:

Professional Engineers of Ontario
Board of the Northeast Power Coordinating Council, Inc.

CURRICULUM VITAE OF ROBERT BOGUSKI

SENIOR VICE PRESIDENT, BUSINESS SERVICES AND INFORMATION TECHNOLOGY

RESPONSIBILITIES:

In his previous position as Vice President, Nuclear Supply Chain, Mr. Boguski's responsibilities included:

- Provision of all materials and services required by the Nuclear business unit.
- Accountability for quality services, procurement engineering, supply planning, sourcing, contract management, warehousing, inventory management, and transportation.

EDUCATION:

University of Victoria (1981) - Bachelor of Arts (Economics)
Queen's School of Business (1998) - Queens' Executive Program
The Logistics Institute (1998) - Professional Logistics Designation, P.Log.
York University (1995) - Logistics Management

EXPERIENCE:

2008 - Present	Ontario Power Generation Inc., Senior Vice President, Business Services and Information Technology
2005 - 2008	Vice President, Nuclear Supply Chain
2003 - 2005	Epilog Services Inc., Managing Partner
2001 - 2003	TransAlta Corporation, Vice President, Supply Chain
1999 - 2001	PricewaterhouseCoopers, National Practice Leader
1988 - 1999	Molson Canada, Vice President, Distribution and Logistics
1981 - 1988	Petro-Canada/Gulf Canada, various Management Positions

MEMBERSHIPS:

Advisory Committee to Mount Royal College, Bissett School of Business
Board accountabilities for Brewers' Distributor Ltd.
The Logistics Institute
Council of Supply Chain Management Professionals

CURRICULUM VITAE OF
NEIL BRYDON

MANAGER, EXTERNAL REPORTING AND POLICY

RESPONSIBILITIES:

As Manager, External Reporting and Policy, Mr. Brydon is responsible for:

- Preparing external financial information including the annual and quarterly Management's Discussion and Analysis (MD&A) and the annual and quarterly consolidated financial statements.
- Maintaining corporate accounting policies and procedures including revisions to current ones and the development of new ones as required in support of the company's compliance with generally accepted accounting principles (GAAP).

EDUCATION:

McMaster University, Hamilton, Ontario (1972) - B.A., Business
Institute of Chartered Accountants of Ontario (1976) - Chartered Accountant

EXPERIENCE:

1978 - Present	Ontario Power Generation Inc., Ontario Hydro
2005 - Present	Manager, External Reporting and Policy

MEMBERSHIPS:

The Institute of Chartered Accountants of Ontario
The Canadian Institute of Chartered Accountants
Canadian Electricity Association (CEA), Ottawa, Ontario, Accounting and Finance Committee, Chair
Edison Electric Institute (EEI), Washington, D.C., U.S.A., Accounting Standards Committee, Member

CURRICULUM VITAE OF
ANGELO CASTELLAN

DIRECTOR, NUCLEAR WASTE BUSINESS SUPPORT

RESPONSIBLITIES:

As Director, Nuclear Waste Business Support, Mr. Castellan is responsible for:
- Coordinating and preparing the business plan and budget for the Nuclear Waste Management Division.
- Preparation of nuclear waste lifecycle cost estimates, and liability management/segregated fund accounting.
- Monitoring and assessing divisional performance against established plans.
- Working with regulators, local communities and other stakeholders in the pursuit of long-term management options for low and intermediate level radioactive waste.

EDUCATION:

York University (1989) - Master of Business Administration (MBA)
University of Toronto (1978) - Bachelor of Applied Science (BASc) in Chemical Engineering

EXPERIENCE:

1978 - Present	Ontario Power Generation Inc., Ontario Hydro
2003 - Present	Director, Nuclear Waste Business Support

MEMBERSHIP:

Professional Engineers Ontario (1980)

CURRICULUM VITAE OF
MARIO CORNACCHIA

DIRECTOR, COMMERCIAL SERVICES
INSPECTION AND MAINTENANCE AND COMMERCIAL SERVICES

RESPONSIBILITIES:

As Director, Commercial Services, Mr Cornacchia's responsibilities include:

- Accountability for the international marketing, sales and contract management of OPG's isotope products and heavy water services.
- Coordinating the management of heavy water inventory to meet the current and future needs of OPG's nuclear fleet.
- Ongoing oversight of the lease and associated agreements with Bruce Power, and ensuring appropriate lessor-lessee relationships are maintained.

EDUCATION:

University Of Toronto (1973)

EXPERIENCE:

1990 - Present	Ontario Power Generation Inc., Ontario Hydro
2007 - Present	Director, Commercial Services
1998 - 2007	Director, Isotope Sales & Heavy Water Programming
1995 - 1998	Marketing Manager, New Business Ventures
1993 - 1995	Manager, Key Accounts, Energy Sales
1990 - 1993	Manager, Consumer Markets, Energy Management
1986 - 1990	Director of Marketing, Philips Electronics Ltd
1982 - 1986	Director of Marketing, Braun Canada Ltd
1978 - 1982	Merchandising Manager, Canadian Admiral Corp
1974 - 1978	Sales/Product Manager, Quasar Electronics Ltd

CURRICULUM VITAE OF MUTIZWA DENNIS DODO

CONTROLLER, INSPECTION AND MAINTENANCE SERVICES

RESPONSIBILITIES:

As Controller, Inspection and Maintenance Services, Mr Dodo's responsibilities include:

- Monthly financial reporting and analysis
- Budget and financial strategic management, including preparation of Inspection and Maintenance Services' input to business planning
- Accounting and related internal controls

EDUCATION:

Revier College NH USA (2001) - Master of Business Administration
University of the District of Columbia (1998) - Graduate Certificate International Finance and Accounting
University of Zimbabwe (1994) - Bachelor of Business Studies (Accounting)

EXPERIENCE:

2005 - Present	Ontario Power Generation Inc.
2007 - Present	Controller - Inspection and Maintenance Services
2005 - 2007	Internal Audit Professional
2004 - 2005	Robert Half Management Resources (ON)
2002 - 2004	Brandot International Limited (USA)
1996 - 2002	Parexel International (USA)
1994 - 1996	Arthur Anderson LLP (Zimbabwe)

MEMBERSHIPS:

Institute of Internal Auditors Toronto
Association of Certified Fraud Examiners
American Institute of Certified Public Accountants (DC)
Association of Chartered Certified Accountants (Zimbabwe)

CURRICULUM VITAE OF
JOAN FRAIN

MANAGER, WATER POLICY AND PLANNING
WATER RESOURCES DIVISION

RESPONSIBILITES:

As Manager, Water Policy and Planning for the Water Resources and Aboriginal Relations Division, Ms. Frain's responsibilities include:

- Participation in water control boards and committees
- Negotiation of water and land agreements with governments, other generators and stakeholders
- Provision of strategies for water management planning, industry self regulation, delineation of land base requirements
- Payment calculation for gross revenue charge (GRC), water rentals and other water agreements
- Hydroelectric energy and capacity forecast
- Regulated site variance report

EDUCATION:

University of Waterloo (1981) - Bachelor of Applied Science, Civil Engineering

EXPERIENCE:

1982 - Present	Ontario Power Generation Inc., Ontario Hydro
2000 - Present	Manager - Water Policy and Planning
1998 - 2000	Senior Engineer - Water Resources Policy
1991 - 1998	Engineer – Operations/Water Resources
1985 - 1991	Hydraulic Design Engineer - Specialist
1982 - 1985	Assistant Engineer - River Control

MEMBERSHIPS:

Professional Engineers of Ontario
Canadian Water Resources Association
Ontario Member, Lake of the Woods Control Board

CURRICULUM VITAE OF
DON B. GAGNON

SYSTEM SUPPORT MANAGER
NIAGARA PLANT GROUP

RESPONSIBILITIES:

As System Support Manager, Niagara Plant Group, Mr. Gagnon's responsibilities include:

- Protection and control engineering and services
- Information technology processes and services
- Security – technical support
- Niagara records and document management
- Drafting services and drawing management

EDUCATION:

Queens University (1990) - Bachelor in Applied Science (Electrical)

EXPERIENCE:

1990 - Present	Ontario Power Generation Inc., Ontario Hydro
2003 - Present	System Support Manager and First Line Manager Sir Adam Beck 1 - Niagara Plant Group
2002 - 2003	Senior Plant Engineer - Niagara Plant Group
2001 - 2002	Program Co-ordinator - Asset Management Department, Niagara Plant Group
1999 - 2000	Genco Y2K - Project Manager - Hydroelectric, OPG
1990 - 2001	Protection and Control Engineer, Niagara Plant Group

MEMBERSHIP:

Professional Engineers of Ontario

CURRICULUM VITAE OF
VINCE F. GONSALVES

DIRECTOR, BUSINESS PLANNING

RESPONSIBILITES:

As Director, Business Planning for Nuclear Finance, Mr Gonsalves' responsibilities include:
- Coordination of the nuclear business planning process
- Preparation of the nuclear business plan
- Coordinating the development of key industry benchmarks for use in planning
- Developing the integrated generation plan

EDUCATION:

University of the Punjab (1970) - Bachelor of Science (Physics, Math)
Certified Management Accountant - Ontario (1976)

EXPERIENCE:

1981 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Director - Business Planning - Nuclear
1997 - 2006	Manager - Business Planning and Strategic Support - Nuclear
1991- 1997	Manager - Planning and Reporting - Fossil Business
1981 - 1991	Section Head - Financial Systems and Reporting - Production Branch
1972 - 1981	External financial positions in the manufacturing sector, Ontario

MEMBERSHIPS:

Board of Directors, Electric Utility Cost Group (EUCG); 1994 - 1997
Nuclear Leadership Team, EUCG; 2005 - Present
Society of Management Accountants

CURRICULUM VITAE OF
SEAN GRANVILLE, P. Eng

DIRECTOR, NUCLEAR PROGRAMS

RESPONSIBILITIES:

As Director, Nuclear Programs, Mr. Granville's responsibilities include:
- Standards and nuclear-wide programs for station operations, maintenance, outage and work control functions.
- Leadership of program 'peer teams' to drive improvements, standardization of processes and increased value for money.
- Station training simulator maintenance, modification and technical support.

EDUCATION:

University of Waterloo (1982) – Bachelor of Applied Science, Mechanical Engineering

EXPERIENCE:

1982 - Present	Ontario Power Generation Inc., Ontario Hydro
2007 - Present	Director, Nuclear Programs
2005 - 2007	Operations Manager, Darlington
2004 - 2005	Assistant Operations Manager, Darlington
1995 - 2004	Authorized Shift Manager, Darlington
1991 - 1995	Authorization Training Program, Darlington
1982 - 1991	Various engineering roles at Pickering B, Pickering A, Darlington & Corporate Office

MEMBERSHIP:

Professional Engineers Ontario

CURRICULUM VITAE OF
DAVID HALPERIN

DIRECTOR, BUSINESS and FINANCIAL PLANNING, CORPORATE FINANCE

RESPONSIBILITIES:

As Director of Financial and Business Planning, Mr. Halperin's responsibilities include:

- Developing, implementing and managing the annual corporate business planning process.
- Providing short-, medium- and long-term forecasts of OPG's financial performance.
- Providing consolidated monthly financial and operational performance reports to senior management, external stakeholders and the OPG Board.

EDUCATION:

University of Toronto (1982) - Masters of Business Administration
University of Toronto (1978) - Bachelor of Applied Science (Industrial Engineering)

EXPERIENCE:

1978 - Present	Ontario Power Generation Inc., Ontario Hydro
1999 - Present	Director, Business and Financial Planning, Corporate Finance
1998 - 1999	Acting Director, Business Planning, Corporate Planning
1995 - 1998	Team Leader, Integration, Corporate Integration and Reporting, Corporate Finance
1993 - 1995	Senior Financial Strategist, Corporate Finance
1991 - 1993	Section Head – Performance Management and Reporting, Controllers' Division
1989 - 1991	Senior Analyst, Corporate Strategic Planning, Executive Office
1988 - 1989	Acting Section Head, Planning and Reporting, Financial Forecasts Department, Controller's Division
1986 - 1987	Supervising Financial Projections Analyst, Financial Forecasts Department, Controller's Division
1983 - 1986	Financial Forecasting Officer, Financial Forecasts Department, Controller's Division
1979 - 1983	Financial Forecasting Analyst, Financial Forecasts Department, Controller's Division
1978 - 1979	Trainee, Graduate Trainee Program

CURRICULUM VITAE OF ROBIN HEARD

VICE PRESIDENT, FINANCIAL SERVICES

RESPONSIBILITIES:

As Vice President, Financial Services, Mr. Heard is responsible for:

- OPG's accounting, financial reporting, taxation, and financial processing services functions;
- overseeing maintenance of the company's accounting policies in compliance with generally accepted accounting principles (GAAP);
- financial controls;
- controllership support to corporate groups; and
- regulatory finance matters.

EDUCATION:

Queen's University, Kingston, Ontario (1992) - B.Comm
Schulich School of Business, York University, Toronto, Ontario (2000) - MBA
Institute of Chartered Accountants of Ontario (1994) - Chartered Accountant
Canadian Institute of Chartered Accountants - In Depth Tax Course 2 Year Program

EXPERIENCE:

2002 - Present	Ontario Power Generation Inc.
2005 - Present	Vice President, Financial Services
2002 - 2005	Director of Accounting
2000 - 2002	Cedara Software Corp.
1998 - 2000	EDS Canada
1996 - 1998	Rogers Mobile
1992 - 1996	PricewaterhouseCoopers (formerly Cooper & Lybrand Chartered Accountants)

MEMBERSHIPS:

The Institute of Chartered Accountants of Ontario
The Canadian Institute of Chartered Accountants
The Canadian Tax Foundation
Edison Electric Institute (EEI), Washington, D.C., U.S.A

CURRICULUM VITAE OF
LORRAINE IRVINE

VICE-PRESIDENT, COMPENSATION AND BENEFITS

RESPONSIBILITIES:

As Vice-President, Compensation and Benefits, Ms. Irvine is responsible for:

- Managing OPG's compensation and benefits elements for all unionized and management employees, including the design, implementation and administration of base pay and incentive pay plans, benefits programs and pension plans.
- Corporate Wellness activities.

EDUCATION:

University of Toronto (1980) - Honours B.A., Specialization in Sociology, Minor in Psychology
Queen's University (2002) - Masters of Business Administration

EXPERIENCE:

1981 - Present	Ontario Power Generation Inc., Ontario Hydro
2003 - Present	Vice-President, Compensation and Benefits

MEMBERSHIPS:

Member and Faculty of World at Work (formerly Canadian Compensation Association)
Conference Board of Canada – Compensation Research Council
Human Resources Planning Society
Society for Human Resources Management
Corporate Executive Board – Compensation/Benefits Roundtables
Association of Canadian Pension Managers
Canadian Pension and Benefits Managers
Advisory Board Member – GTA Total Rewards Association

CURRICULUM VITAE OF
KEN LACIVITA

DIRECTOR, TRADING AND ORIGINATION
ENERGY MARKETS

RESPONSIBILITIES:

As Director, Trading and Origination for OPG Energy Markets, Mr. Lacivita's responsibilities include:

- Management of OPG's trading group, providing ongoing price discovery in energy commodity markets and a transactional platform for hedging OPG's spot market exposure.
- Energy contracting including physical, financial and ancillaries contracting.
- Management of water and power related legacy contracts that were entered into by Ontario Hydro prior to the creation of OPG.
- Generation of incremental revenues through proprietary trading operations.

EDUCATION:

University of Toronto (1978) - Bachelor of Applied Science (Civil Engineering)

EXPERIENCE:

1978 - Present	Ontario Power Generation Inc., Ontario Hydro
2005 - Present	Director, Trading and Origination, OPG Energy Markets
2002 - 2005	Director, Electricity Trading, OPG Energy Markets
1997 - 2002	Term Trader/Power Marketer, OPG Interconnected Markets
1993 - 1997	Engineer, Business Development, Hydroelectric Business Unit
1986 - 1993	Engineer-Operations, Power System Operations Division
1978 - 1986	Civil Design Engineer, Nuclear Containment Group, Design and Development Division

MEMBERSHIPS:

Professional Engineers of Ontario
Canadian Electrical Association, Power Marketing Council

CURRICULUM VITAE OF
LUBNA LADAK

MANAGER, REGULATORY FINANCE

RESPONSIBILITIES:

As Manager, Regulatory Finance, Ms. Ladak's responsibilities include:
- Regulatory accounting and reporting.
- Maintenance of regulatory accounting policies.
- Completion of financial studies for rate regulation purposes.

EDUCATION:

University of Toronto (1989) – Bachelor of Arts
Rotman School of Business, University of Toronto (1991) – MBA
Institute of Chartered Accountants of Ontario (1993) - Chartered Accountant

EXPERIENCE:

1995 - Present	Ontario Power Generation Inc., Ontario Hydro
2005 - Present	Manager, Regulatory Finance
2000 - 2005	Controller, Hydroelectric and Fossil Business Unit
1997 - 1999	Manager, Business Planning and Reporting for Fossil, Hydro, Energy Markets Business Units
1995 - 1997	Manager, Internal Audit
1990 - 1995	Ernst & Young

MEMBERSHIP:

Institute of Chartered Accountants of Ontario

CURRICULUM VITAE OF
ROBERT V. LATIMER

DEPARTMENT MANAGER, STRATEGIC PLANNING, PICKERING A

RESPONSIBIILTIES:

As Department Manager, Strategic Planning, Pickering A, Mr Latimer's responsibilities include:

- Development of the 5-year generation plan for Pickering A, including planned outage scope and duration.
- Assist in development of Pickering A business plan.
- Assist in the management of the Pickering A project portfolio.

EDUCATION:

Bachelor of Mechanical Engineering (1982) - Technical University of Nova Scotia
INPO Engineering Supervisor Professional Development Seminar, October 2004

EXPERIENCE:

1982 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Department Manager, Strategic Planning, Pickering A.
2000 - 2006	Section Manager, Performance Engineering, Pickering A.
1999 - 2000	Assigned to Operating Procedures and Standards section
1996 - 1999	Shift Supervisor in Training
1994 - 1996	Supervisor, Prod-B Technical Co-ordination Unit;
1993 - 1994	Supervisor, PNGS-B Moderator & Auxiliary Systems
1993 - 1993	Supervisor, Special Mechanical Nuclear Projects
1992 - 1993	Acting Superintendent, Mechanical Nuclear Unit;
1987 - 1992	Technical Supervisor - D2O Subunit;
1984 - 1987	System Responsible Engineer - D2O Upgraders;
1982 - 1984	Junior Engineer in Training / Assistant Technical Supervisor - Reactor Structures Subunit

MEMBERSHIP:

Professional Engineers of Ontario

CURRICULUM VITAE OF
RANDY LEAVITT, M. Sc.

DIRECTOR, INVESTMENT MANAGEMENT

RESPONSIBILITIES:

As Director, Investment Management, Mr. Leavitt's responsibilities include:
- Overseeing the development and maintenance of the OPG Nuclear project portfolio.
- Ensuring the implementation of applicable Corporate/OPG Nuclear policies, directives, and standards as related to the Nuclear project portfolio.
- Co-ordinating the implementation of an integrated capital/investment planning and approval process to ensure consistency with strategies and facility life cycle plans.
- Representing Finance on the Asset Investment Screening Committee.
- Recommending alternative investment plans for achieving desired outcomes.

EDUCATION:

Trent University (1980) – Bachelor of Science, Mathematics and Physics
Queens University (1982) – Master of Science, Nuclear Physics
Western University (2006) – Ivey Executive MBA

EXPERIENCE:

1982 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Director, Investment Management – Nuclear Finance
2006	Director, Business Support – Pickering A Nuclear
2002 - 2005	Director, Project Support – Pickering A Return to Service
2002	Manager, Strategy and Work Management – Pickering A Engineering
1998 - 2002	Manager, Programming – Pickering A and B Nuclear
1993 - 1998	Outage Manager - Pickering A Nuclear
1991 - 1993	Shift Manager - Pickering A Nuclear
1982 - 1991	Various positions in Training, Engineering and Reactor Safety organizations.

MEMBERSHIP:

American Nuclear Society

CURRICULUM VITAE OF DANA LETTS

OUTAGE PROGRAM MANAGER NUCLEAR PROGRAMS AND TRAINING

RESPONSIBILITIES:

As Outage Program Manager for the Nuclear Programs and Training, Mr Letts' responsibilities include:

- Management of the nuclear level outage program requirements, standards and procedures, and monitoring/ evaluation of the program implementation at the OPG-Nuclear sites to ensure outage performance remains aligned with the business goals of OPG.
- Oversight of the integrated outage and generation planning process, in support of OPG business planning.

EDUCATION:

2008 Athabasca University, B.Comm, (progressing 2nd year)

EXPERIENCE:

1990 - Present	Ontario Power Generation Inc., Ontario Hydro
2005 - Present	Outage Program Manager, OPG-Nuclear
2004 - 2005	Senior Advisor, Nuclear Operations, OPG-Nuclear
2003 - 2004	System Window Coordinator, Darlington Nuclear Generating Station
2000 - 2004	System Window Coordinator, Pickering B Nuclear Generating Station
1999 - 2000	Operations Outage Coordination, Pickering B Nuclear Generating Station
1995 - 1999	Authorized Nuclear Operator in Training, Pickering B Nuclear Generating Station
1990 - 1995	Nuclear Operator, Pickering B Nuclear Generating Station

CURRICULUM VITAE OF
FRED LONG

VICE PRESIDENT, FINANCIAL PLANNING

RESPONSIBILITIES:

As Vice President, Financial Planning, Mr. Long' responsibilities include:
- Directing the company's financial and business planning, management reporting, and financial assessment of investment opportunities.
- Managing the company's property tax function.

Prior to his current position, Mr. Long was Director of Financial Strategy for Ontario Hydro, the predecessor company of OPG, where he played a leadership role in the financial restructuring of Ontario Hydro into its successor companies.

EDUCATION:

Essex University (UK) (1970) - BA (Physics)
McMaster University (1976) - PhD (Physics)

EXPERIENCE:

1976 - Present	Ontario Power Generation Inc., Ontario Hydro
1999 - Present	Vice President Financial Planning, OPG
1994 - 1999	Director/Manager Financial Strategy, Ontario Hydro
1980 - 1994	Various positions responsible for short and long-term financial planning, financial policy and strategy, and operational audit.
1976 - 1979	Assistant Technical Supervisor, Fuel and Physics Department, Nuclear Generation Division, Ontario Hydro

CURRICULUM VITAE OF JOHN G. MAUTI

DIRECTOR, NUCLEAR REPORTING

RESPONSIBILITIES:

As Director of Nuclear Reporting, Mr. Mauti's accountabilities include:

- Maintain all financial reporting for OPG Nuclear business and management of costing systems that generate cost reporting across the business.
- Manage nuclear accounting and reporting staff.
- Maintain nuclear financial policies and practices, financial systems, control systems and their effective operation.
- Produce nuclear key performance reporting used in communicating with senior management, and the shareholder.
- Contribute to and liaise with benchmark organizations relating to nuclear financial benchmarking used by OPG.
- Integration of corporate business practices within the nuclear organization.

EDUCATION:

Wilfrid Laurier University (1987) – Honours Bachelor of Business Administration

EXPERIENCE:

1991 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Director of Nuclear Reporting
2002 - 2006	Director of Restructuring, Commercialization and Nuclear Support
1999 - 2001	Director of Accounting – OPG Finance
1997 - 1999	Manager Financial Reporting and Internal Control – Nuclear Finance
1991 - 1997	Various analytical and management positions in Finance including Financial Advisor, Audit Senior and Audit Client Services Manager
1987 - 1991	Auditor General of Ontario

MEMBERSHIP:

Institute of Chartered Accountants of Ontario (1991) - Chartered Accountant Designation

CURRICULUM VITAE OF
MARIO MAZZA

DIRECTOR, BUSINESS SUPPORT AND REGULATORY AFFAIRS
HYDRO BUSINESS UNIT

RESPONSIBILITIES:

As Director Business Support and Regulatory Affairs - Hydro Business Unit, Mr. Mazza's responsibilities include:

- Preparation of the Hydro business plan and annual budget
- Performance reporting and IT infrastructure support
- Benchmarking
- Regulatory support (rate regulation, IPSP, other regulatory issues support)
- Asset management (oversight, prioritization, life cycle planning, etc., for Hydro business)
- Production support and market operations support
- Development of hydro annual incentive plan
- Hydro records and document management

EDUCATION:

University of Toronto (1979) - Bachelor of Applied Science (Civil Engineering)

EXPERIENCE:

1979 - Present	Ontario Power Generation Inc., Ontario Hydro
2005 - Present	Director, Business Support & Regulatory Affairs, Hydro
2002 - 2005	Manager - Programming and Business Support, Electricity Production
1998 - 2002	Senior Advisor - Business Programming Dept, Hydroelectric Business Unit
1986 - 1998	Civil Maintenance and Projects Engineer, Civil Works Department, Hydraulic Generation Division
1979 - 1986	Civil Design Engineer, Nuclear Containment Group-Civil, Design and Development Division

MEMBERSHIP:

Professional Engineers of Ontario

CURRICULUM VITAE OF MICHAEL MCFARLANE

OUTAGE MANAGER
Darlington

RESPONSIBILITIES:

As Outage Manager for the Darlington Nuclear Generating Station, Mr McFarlane's responsibilities include:

- Planning and executing planned outages.
- Preparing and executing forced outages.
- Preparing outage schedule and duration for the 5 year business plan.

EDUCATION:

Algonquin College 1979 - Instrument Technician

EXPERIENCE:

1979 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Outage Manager, Darlington Nuclear Generating Station
2004 - 2005	Radiation Protection Manager, Darlington Nuclear Generating Station
1997 - 2004	Section Manager Maintenance, Fuel Handling, Darlington Nuclear Generating Station
1991 - 1997	First Line Manager, Fuel Handling Maintenance Nuclear Generating Station
1986 - 1991	First Line Manager Assistant, Darlington Nuclear Generating Station
1979 - 1986	Shift Control Technician, Bruce A Nuclear Generating Station

CURRICULUM VITAE OF ROBERT C. MORRISON

VICE PRESIDENT, ENGINEERING AND MODIFICATIONS AND CHIEF NUCLEAR ENGINEER

RESPONSIBILITIES:

In his previous position as Vice President, Inspection and Maintenance Services, Nuclear Generation Development Services, Mr Morrison's responsibilities included:

- Plan, resource and conduct specialized inspection and maintenance activities required to support OPG nuclear stations and, as contracted, Bruce Power. Specific inspections include piping, fuel channels, feeder pipes, fuel bundles, steam generators, heat exchangers, turbines and specialized measurements.
- Maintain inspection tools and delivery machines and conduct reactor maintenance
- Administer projects and engineering services for advanced non-destructive evaluation methods, tools and delivery machines.

EDUCATION:

University of Toronto (1978) - Bachelor of Applied Science (Engineering Science)

EXPERIENCE:

1978 - Present	Ontario Power Generation Inc., Ontario Hydro
2008 - Present	Vice President Engineering and Modifications and Chief Nuclear Engineer
2004 - 2008	Vice President, Inspection & Maintenance Services, NGDS
2001 - 2004	Director – Operations & Maintenance, Darlington Nuclear
1999 - 2001	Manager – Maintenance Production, Darlington Nuclear
1997 - 1999	Vice President – Managed Systems, Ontario Hydro Nuclear
1997 - 1997	Manager – Programming, Bruce Nuclear
1993 - 1997	Manager – Nuclear Safety Department, Bruce B Nuclear
1993 - 1993	Technical Manager, Bruce NGS-B
1989 - 1993	Technical Superintendent – Planning, Bruce NGS-B
1988 - 1989	Technical Superintendent – NGD Directorate
1985 - 1988	Training Superintendent – M&P Operations, Nuclear Staffing Group
1983 - 1985	Authorized Nuclear Shift Supervisor, NPD-NGS
1982 - 1983	Shift Supervisor in Training, NPD-NGS
1980 - 1982	Assistant Technical Supervisor, NPD-NGS
1978 - 1980	Junior Engineer, NPD-NGS

MEMBERSHIPS:

Professional Engineer APEO (since 1980)
Nuclear Shift Manager Authorization
Authorized Duty Manager

CURRICULUM VITAE OF
PAUL PASQUET

Deputy Site Vice President, Pickering B

RESPONSIBILITIES:

As Deputy Site Vice President, Pickering B, Mr. Pasquet's responsibilities include:

- Management of the station finance and strategic planning functions, including preparation of the station's input to nuclear business planning
- Management of the Pickering B fire protection and regulatory functions (eg., station licensing)
- Management of the performance improvement and nuclear oversight function

EDUCATION:

Trent University (1979) – Bachelor of Applied Science, Physics

EXPERIENCE:

1979 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Deputy Site Vice President – Pickering B
2004 - 2005	Director of Operations and Maintenance – Pickering A
2003 - 2004	Director of Operations Support, Nuclear Operations
1999 - 2003	Operations Production Manager – Pickering A
1997 - 1999	Lay-up and Recovery Manager – Pickering A
1996 - 1997	Acting Generating Units Manager – Pickering A
1985 - 1996	Shift Manager – Pickering A, Operating Superintendent
1979 - 1985	Various positions within Ontario Hydro nuclear

CURRICULUM VITAE OF
WILLIAM R. ROBINSON

SENIOR VICE PRESIDENT, NUCLEAR PROGRAMS AND TRAINING

RESPONSIBILITIES:

As Senior Vice President - Nuclear Programs and Training, Mr. Robinson is responsible for:
- Provision of services for nuclear training, security, facilities management, document services, record management, and administrative support.
- Development, implementation and monitoring of major programs common to all nuclear stations, ensuring that best practices are implemented across the fleet.
- Planning and administration of the nuclear workforce development plan.

EDUCATION:

University of Missouri (1974) - Bachelor of Science, Electrical Engineering
University of Michigan (1996) - Energy Services Executive Program

EXPERIENCE:

1998 – Present	Ontario Power Generation Inc., Ontario Hydro
2005 - Present	Senior Vice President, Nuclear Programs and Training
2002 – 2005	Senior Vice President, Pickering A Return to Service
1999 – 2002	Site Vice President, Pickering B
1998 – 1999	Maintenance Mentor, Pickering B
1993 – 1998	Site Vice President, Shearon Harris Nuclear Plant, Carolina Power & Light
1992 – 1993	Site Vice President, Trojan Nuclear Plant, Portland General Electric
1990 – 1992	Plant General Manager, Trojan Nuclear Plant, Portland General Electric
1987 – 1990	Assistant Plant Manager, Callaway Nuclear Plant, Union Electric Company
1983 – 1990	Various Supervisory Positions, Callaway Nuclear Plant
1980 – 1983	Shift Engineer, Expended Core Facility, Westinghouse Electric Co. Company
1968 – 1980	U. S. Navy

MEMBERSHIPS:

Board of Governors, Durham College
Board of Governors, University of Ontario Institute of Technology

CURRICULUM VITAE OF
J. CRAIG SELLERS

CHIEF ENGINEER, NUCLEAR NEW BUILD

RESPONSIBILITIES:

In his previous position, as Vice President of Engineering and Modifications and Chief Nuclear Engineer, Mr. Sellers' responsibilities included:

- Leadership of all elements of OPG Nuclear engineering, including assurance that OPG Nuclear engineering programs meet applicable codes and standards.
- Accountability for the nuclear project portfolio, including Chair of the Asset Investment Screening Committee.
- Provision of specialised engineering expertise associated with major nuclear components (feeders, fuel channels, steam generators), nuclear safety analysis, and design support for the nuclear project portfolio.
- Management of the OPG Nuclear research & development program.

As Chief Engineer, Nuclear New Build, Mr. Sellers' responsibilities include:

- Acting as the OPG Design Authority for new nuclear, including leading the OPG input into the new nuclear build technology selection process
- Provision of technical, design and operations input to support Infrastructure Ontario in the selection of the preferred new nuclear technology option

EDUCATION:

University of Toronto (1978) – Bachelor of Applied Science, Chemical Engineering

EXPERIENCE:

1979 - Present	Ontario Power Generation Inc., Ontario Hydro
May 2008 - Present	Chief Engineer, Nuclear New Build
2006 - April 2008	VP Engineering and Modifications and Chief Nuclear Engineer
2005 - 2006	Director, Supply Planning, Nuclear Supply Chain
2003 - 2005	Director, Restart Engineering, Pickering A
2001 - 2002	Manager, Senior Plant Design, Pickering B
1999 - 2001	Manager, Maintenance Production, Pickering B
1998 - 1999	Engineering Manager, Pickering B
1993 - 1998	Technical Superintendent, Pickering A
1990 - 1993	Shift Supervisor, Pickering A
1984 - 1990	Technical Supervisor
1979 - 1984	Commissioning Engineer/ Assistant Technical Supervisor

MEMBERSHIP:

Professional Engineers Ontario - 1981

CURRICULUM VITAE OF
MARK SHEA

ASSET AND TECHNICAL SERVICES MANAGER
OTTAWA / ST LAWRENCE PLANT GROUP

RESPONSIBILITIES:

As Asset and Technical Services Manager for the Ottawa/ St Lawrence Plant Group, Mr. Shea's responsibilities include:

- Preparation of Plant Group business plan
- Manage Plant Group assets (10 generating stations and 3 control dams) including investment planning and condition assessment
- Provide engineering support and engineering oversight
- Provide drafting, records/ document management and managed system support
- Plant Group single point of contact (SPOC) for IT and telecom

EDUCATION:

McGill University (1982) - Bachelor of Engineering (Mechanical)

EXPERIENCE:

1982 - Present	Ontario Power Generation Inc., Ontario Hydro
2002 - Present	Asset and Technical Services Manager, Ottawa/ St Lawrence Plant Group, Hydro
2000 - 2002	Asset Manager, Ottawa/ St Lawrence Plant Group, Hydro
1995 - 2000	District Technical Supervisor/ FLM Technical, Ottawa/ St Lawrence Plant Group, Hydro
1988 - 1995	Maintenance Supervisor/ Engineering Supervisor, Lennox Generating Station, Fossil
1982 - 1988	Assistant Supervisor - Mechanical Maintenance, Nanticoke Generating Station, Fossil

MEMBERSHIPS:

Professional Engineers of Ontario
Canadian Dam Association

CURRICULUM VITAE OF
COLLEEN SIDFORD

VICE PRESIDENT, TREASURER

RESPONSIBILITIES:

As Vice President, Treasurer, Ms. Sidford is responsible for:
- Providing financial leadership to the Corporate Treasury function which includes Treasury Operations, Insurance Risk Management, Pension Fund Management, and Nuclear Fund Management.
- Management of the Corporation's liquidity, ensuring access to short term and long term financing, and funding for OPG's capital and generation redevelopment projects.
- Management of OPG's long term investments which includes the Pension Fund, and the Nuclear Decommissioning Fund and Nuclear Used Fuel Fund.
- The Corporate Insurance program which provides catastrophic insurance coverage for all of OPG's physical assets as well as liability insurance.

EDUCATION:

Ontario Art College (1974 - 1975) - Certificate Program

EXPERIENCE:

2003 - Present	Ontario Power Generation Inc.
2005 - Present	Vice President - Treasurer
2003 - 2005	Assistant Treasurer
1995 - 2003	Sidford & Associates Inc. - International Treasury Consulting
1997 - 2003	Europe Based Operation
1995 - 1997	Canada Based Operation
1991 - 1995	The Molson Companies Inc.
1994 - 1995	The Molson Companies Inc., Canada - Assistant Treasurer
1991 - 1994	Diversey Corporation (subsidiary of The Molson Companies), Belgium - Global Treasury Manager
1989 - 1991	Bank of America Canada, Vice President and Manager - Global Payment Services
1975 - 1989	Bank of Nova Scotia, Various positions in IT, Consumer Banking, Corporate Cash Management

MEMBERSHIPS:

Women in Nuclear (WIN)
Manufacturers Alliance of Public Institutions (MAPI)
Association of Financial Professionals (AFP)
Treasury Management Association of Canada (TMAC)
Society of Corporate Treasurers
Treasury Leadership Roundtable
Pension Investment Association of Canada (PIAC)

CURRICULUM VITAE OF
THOMAS STAINES

CONTROLLER, CORPORATE ACCOUNTING
FINANCE

RESPONSIBILBITIES:

As Controller, Corporate Accounting, Mr. Staines is responsible for:

- The controllership function in support of Finance, CIO, Human Resources, Corporate Centre and Real Estate, including accounting, financial reporting, business planning and budgeting and advice on financial and business decisions.
- Maintaining the general ledger and chart of accounts, preparing OPG and business unit management reports, preparing OPG's consolidated financial statements, and maintaining the corporate cost allocation model.

EDUCATION:

Acadia University (1975) - Bachelor of Business Administration

EXPERIENCE:

1982 - Present	Ontario Power Generation Inc., Ontario Hydro
2002 - Present	Controller, Corporate Accounting
2000 - 2002	Controller, Corporate Support Services
1996 - 2000	Manager, Financial Support Services
1993 - 1996	Manager, Accounting, Fossil
1991 - 1993	Supervisor, Budgeting and Reporting, Fossil
1982 - 1991	Contract Audit

MEMBERSHIP:

Society of Management Accountants

CURRICULUM VITAE OF
LAURIE SWAMI

DIRECTOR OF LICENSING, NEW GENERATION DEVELOPMENT

RESPONSIBILITIES:

As Director of Licensing, New Generation Development, Ms. Swami's responsibilities include:

- Overall responsibility for licensing of new nuclear generation and refurbishments
- Overseeing regulatory submissions and commitments in support of the Pickering B refurbishment assessment
- Participation in the management team review and critique of scope and associated costs for refurbishment projects
- Completion of the environmental assessment for new nuclear generation and refurbishment projects, including the public consultation program

EDUCATION:

Queen's University (1985) – Bachelor of Science, Engineering Chemistry
York University (1994) - Masters of Business Administration

EXPERIENCE:

1986 - Present	Ontario Power Generation Inc., Ontario Hydro
2006 - Present	Director, Licensing, Nuclear Generation Development
2005 - 2006	Director, Enterprise Risk Management OPG
2003 - 2005	Director, Environment, OPG-Nuclear
2003	Manager Radiation Protection, Pickering B
2001 - 2003	Manager, Chemistry, Pickering Nuclear
2000	Manager, IIP Co-ordination, Pickering Nuclear
1997- 2000	Manager, Environmental Compliance, Pickering Nuclear
1992 - 1997	Technical Supervisor, Environment, Pickering Nuclear
1986 - 1992	Various engineering positions, Ontario Hydro

MEMBERSHIP:

Women In Nuclear, Durham - Founding Member

DRAFT ISSUES LIST

OPG's pre-filed evidence addresses the following issues:

- Capital programs and capital expenditure levels
- Production forecasts
- OM&A expenses
- Rate base
- Depreciation expense
- Allocation of corporate costs
- Other revenues
- Revenue requirement impact associated with nuclear waste and decommissioning liabilities
- Capital structure and rate of return
- Design of payment amounts
- Disposition of balances in existing variance and deferral accounts
- Continuation of certain existing and creation of new variance and deferral accounts
- Interim rates

RESPONSE TO METHODOLOGY REPORT

1.0 INFORMATION RESPONDING TO THE METHODOLOGY REPORT

The OEB's filing guidelines request that OPG provide the following additional information. The specific filing guideline is cited and the corresponding reference to the requested information is provided in the chart below.

Filing Guideline	OPG's Filing
Planned outage schedules (actual and forecast) for the nuclear units for the period 2005 to the date of filing; planned outage schedules for the period from the date of filing through, as far as possible, to the end of the Test Years; the reasons for each planned outage; and, actual or proposed duration and actual or expected impact on output of each planned outage. A listing of all unscheduled (forced) outages for the period 2005 to the date of fling; the reason, duration and impact on output of each forced outage; and, the action taken by OPG in response to forced outages, such as corrective action taken to prevent future occurrences.	Requested outage data are presented for the nuclear facilities in Ex. E2-T1-S1.
A schedule of the hours when the total combined output from the prescribed hydroelectric generation assets exceeded 1500 MWh and 1900 MWh per hour in the period from 2005 to the date of filing and the actual level of output for those hours by station, including the Beck Pump Storage facility.	A summary of these data is presented in Appendix A. OPG's proposal for the incentive mechanism for the regulated hydroelectric facilities is presented in Ex. I1-T1-S1.
A schedule of hourly Beck Pump Storage MWh consumption and production and the Hourly Ontario Energy Price ("HOEP") for those hours, from 2005 to the filing date.	A summary of these data is presented in Appendix B. OPG's proposal for the incentive mechanism for the regulated hydroelectric facilities, including the Sir Adam Beck Pump Generating Station ("PGS") is presented in Ex. I1-T1-S1.
A schedule of when prescribed generation asset	A summary of these data is

prices for the nuclear and hydroelectric facilities exceeded HOEP, by day and hour on a quarterly basis for the period 2005 to the date of filing; a quarterly summation of these hours; and, a calculation of the percentage of total hours in each quarter when these prices exceeded HOEP.	presented in Appendix C, and further discussed below in section 2.

2.0 COMPARISON OF PAST PAYMENT AMOUNTS TO MARKET PRICES

The OEB's Methodology Report stated: "The Board will also solicit input on whether the payment amounts for any of the prescribed generation assets should be capped or limited in some fashion if past payments have exceeded market prices for an extended period." In response to this, the filing guidelines requested the information cited in section 1.0 above and presented in Appendix C. The data shown in Appendix C compare HOEP from the IESO-administered energy market with OPG's regulated payment amounts. Although both are measured in $/MWh, there are significant differences between them that should be noted in any comparison.

HOEP is the hourly market clearing price in Ontario for energy. It represents the average of the 12 five-minute prices paid to dispatchable generation in each hour and is based on the offers and bids received by the IESO. Offers of energy from generators in Ontario and suppliers from other jurisdictions, as well as bids for energy from dispatchable buyers, are provided to the IESO in advance of dispatch. The IESO ranks generator offers in merit order from cheapest to most expensive for each hour. The market price reflects the last offer accepted by the IESO to balance supply. All generators selected for dispatch are paid the market clearing price regardless of their offers. This encourages generators to offer based on their marginal production costs in order to maximize their chances of being selected for dispatch. An unregulated generator gets paid HOEP for all hours, many of which are in excess of their offers. The revenues in excess of the generator's offer are necessary to allow the unregulated generator to earn sufficient revenues to cover other costs which are not specifically included in its hourly offers.

OPG's regulated payment amounts are not based on marginal cost offers, but rather on the total cost of service associated with the regulated facilities. This means that the regulated payment amounts include elements associated with recovering fixed costs, depreciation expenses, interest charges, return on equity, etc. which would not exist in an offer based on marginal costs. These elements must be recovered through the regulated payment amounts since this is the only mechanism that exists for covering those costs.

Within Ontario, many generators have contracts with the Ontario Power Authority which provide a mechanism to ensure recovery of fixed costs when market prices are not sufficient to allow their recovery. In many electricity markets there are capacity markets in addition to energy markets to allow generators to recover fixed costs that are not recovered in the energy markets.

It also should be noted that the Market Surveillance Panel has recognized that Ontario market prices are often insufficient to allow generators to earn sufficient revenues[1]. This results in marginal generators not covering all costs and discourages additional investment, thereby necessitating other means of ensuring long-term adequacy, such as contracting. In its cost benefit analysis associated with operating reserve, the IESO also recognizes this fact[2].

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[1] MSP Report dated December 13, 2006 (page vii).
[2] IESO CBA on Operating Reserve states "The OPA as central planner is charged with identifying future investment needs in the province and contracting for this investment. In general, they are tasked with providing the incentives (through contract) to invest when the market itself does not provide these incentives." page 13.

LIST OF ATTACHMENTS

APPENDIX A

Hours Regulated Hydroelectric Generation Exceeded 1500 MWh and 1900 MWh

Chart 1 below provides a schedule of the hours when the total combined output from the regulated hydroelectric facilities exceeded 1500 MWh and 1900 MWh in an hour.

The hour by hour listing is not presented below because of the large quantity of hourly data, but the data has been provided electronically to the OEB and is available from the OEB.

Chart 1

	2005	2006	2007
Number of hours > 1500 MWh	7873	7826	7906
Number of hours > 1900 MWh	6226	6130	5694

APPENDIX B

Sir Adam Beck PGS Production and Consumption

Chart 1 below provides a schedule of annual Sir Adam Beck Pump Storage MWh consumption and production from January 1, 2005 – December 31, 2007. Also shown is the average Hourly Ontario Energy Price ("HOEP") during pump activity and then average HOEP during generation activity.

The hour by hour listing is not presented below because of the large quantity of hourly data, but the data has been provided electronically to the OEB and is available from the OEB.

Chart 1

	PGS Consumption (MWh)	PGS Production (MWh)	Average HOEP during Pump ($/MWh)[1]	Average HOEP during Generation ($/MWh)[2]
2005	271.8	127.5	53.38	84.29
2006	283.0	129.6	37.15	54.48
2007	268.8	118.7	37.86	57.10

[1] Average is not load weighted. HOEP for each hour of net pumping is summed and divided by the total number of net pump hours in the year.
[2] Average is not load weighted. HOEP for each hour of net generation is summed and divided by the total number of net generation hours in the year.

APPENDIX C

HOEP versus Regulated Payment Amounts

Chart 1 below provides a quarterly summation of hours where the regulated payment amounts exceeded Hourly Ontario Energy Price ("HOEP"), with a calculation of the percentage of total hours in each quarter when regulated payment amounts exceeded HOEP.

The hour by hour listing is not presented below because of the large quantity of hourly data, but the data has been provided electronically to the OEB and is available from the OEB.

Chart 1

	Hydroelectric	Nuclear
2005 – Q1		
Total hours per quarter	38	932
Percentage of quarter	1.76	43.15
2005 – Q2		
Total hours per quarter	136	1022
Percentage of quarter	6.23	46.79
2005 – Q3		
Total hours per quarter	195	671
Percentage of quarter	8.83	30.39
2005 – Q4		
Total hours per quarter	142	935
Percentage of quarter	6.43	42.35
2006 _ Q1		
Total hours per quarter	133	1235
Percentage of quarter	6.16	57.18
2006 _ Q2		
Total hours per quarter	634	1492
Percentage of quarter	29.03	68.32
2006 _ Q3		
Total hours per quarter	880	1498
Percentage of quarter	39.86	67.84
2006 _ Q4		
Total hours per quarter	940	1586
Percentage of quarter	42.57	71.83
2007 _ Q1		
Total hours per quarter	471	1213

	Hydroelectric	Nuclear
Percentage of quarter	21.81	56.16
2007 _ Q2		
Total hours per quarter	1045	1533
Percentage of quarter	47.85	70.19
2007 _ Q3		
Total hours per quarter	852	1385
Percentage of quarter	38.59	62.73
2007 _ Q4		
Total hours per quarter	663	1308
Percentage of quarter	30.03	59.24

ACRONYMS

AIP	Annual Incentive Plan
AGC	Automatic Generation Control
ALARA	As Low As Reasonably Achievable
BCS	Business Case Summary
CANDU	Canadian Deuterium Uranium.
CEA	Canadian Electrical Association
CMSC	Congestion Management Settlement Credits
CNSC	Canadian Nuclear Safety Commission
DRC	Depreciation Review Committee
DSO	Dispatch Scheduling Optimizer
EA	Environmental Assessment
EBIT	Earnings Before Interest and Income Taxes
EFOR	Equivalent Forced Outage Rate
EPSCA	Electrical Power Systems Construction Association
EUCG	Electric Utility Cost Group
FDR	Franklin D. Roosevelt
FEPO	Forced Extension to a Planned Outage
FLR	Force Loss Rate
Fosters	Foster Associates, Inc.
FTE	Full-Time Equivalents
GAAP	Generally Accepted Accounting Principles
GLERL	Great Lakes Environmental Research Laboratory
GRC	Gross Revenue Charges
GST	Goods and Services Tax
HVAC	Heating, Ventilation and Air Conditioning System
IMS	Inspection and Maintenance Services
INCW	International Niagara Control Works
ISO	International Organization of Standardization
ISR	Integrated Safety Review
IT	Information Technology
IT Assets	Certain Shared Chief Information Office and Energy Markets Assets
IVA	Interim Variance Account
L&ILRW	Low and Intermediate Level Radioactive Waste
MNR	Ministry of Natural Resources
MOU	Memorandum of Understanding
NFWA	Nuclear Fuel Waste Act
NHSS	New Horizon System Solutions
NOAA	National Oceanic and Atmospheric Administration
NOSS	Nuclear Operations Support and Services
NPI	Nuclear Performance Index
NSCA	Nuclear Safety and Control Act

NYPA	New York Power Authority
O. Reg.	Ontario Regulation
OCT	Ontario Capital Tax
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
OM&A	Operations, Maintenance and Administration Costs
ONFA	Ontario Nuclear Funds Agreement
OPEB	Other Post-Employment Benefits
OPG	Ontario Power Generation Inc.
OR	Operating Reserve
OSPG	Ottawa - St.Lawrence Plant Group
PARTS	Pickering A Return To Service
PCI	Plant Condition Index
PGS	Pump Generating Station
PINO	Performance Improvement and Oversight
PIR	Post Implementation Review
PST	Provincial Sales Tax
PUEC	Nuclear Production Unit Energy Cost
PWU	Power Workers' Union
ROC	Risk Oversight Committee
ROE	Return on Equity
RPP	Registered Pension Plan
Rudden	R.J. Rudden Associates
SLAR	Spacer Location and Relocation Program
SMO	Segregated Mode of Operation
Society	Society of Energy Professionals
TRF	Tritium Removal Facility
UCF	Unit Capability Factor
VBO	Vacuum Building Outage
WANO	World Association Of Nuclear Operators
WDP	Workforce Development Plan

FINANCIAL SUMMARY

1.0 PURPOSE

The purpose of this evidence is to provide OPG's 2005 2006, and 2007 audited annual consolidated financial statements as well as an overview of how the provisions of O. Reg. 53/05 are reflected in the filing. This evidence also demonstrates how the results in the financial statements have been reconciled with those in the filing.

2.0 ANNUAL AUDITED FINANCIAL STATEMENTS

OPG has a fiscal year-end of December 31. OPG's consolidated financial statements are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The consolidated financial statements include the accounts of OPG and its subsidiaries, and provide financial information by business segment: regulated – nuclear, regulated – hydroelectric, unregulated – hydroelectric, and unregulated – fossil-fuelled and "other." OPG's 2005 and 2006 annual reports, which include audited financial statements, and 2007 audited annual consolidated financial statements including Management's Discussion and Analysis (MD&A), are presented in Appendix A.

With the introduction of regulated prices commencing April 1, 2005, OPG adopted certain accounting policies specific to rate-regulated operations, which chiefly relate to accounting for income taxes and recognition of regulatory assets and liabilities. The accounting policy related to income taxes is discussed in Ex. F3-T2-S1 Section 4.0. Regulatory assets and liabilities recorded by OPG reflect variance and deferral accounts, which are discussed in Ex. J1-T1-S1.

OPG is a reporting issuer under the *Securities Act*, and is subject to continuous disclosure obligations under this Act. This includes the requirement to file annual and interim financial statements and certifications on internal control over financial reporting with the Ontario Securities Commission. The annual financial statements are audited.

OPG's historic information provided in this application reflects the application of regulatory constructs (e.g., rate base) to the segregated information for the regulated operations used to establish a regulatory revenue requirement. OPG's forecast information for the test period is largely prepared using the accounting policies disclosed in the audited annual consolidated financial statements. Where appropriate, regulatory constructs are applied to certain costs or balances in order to make them consistent with generally accepted regulatory principles. These differences are highlighted in the various sections of the application.

Under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation and to file federal and provincial income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation.

3.0 PROVISIONS OF THE REGULATION

Chart 1 presents the relevant sections of O. Reg. 53/05 along with associated cross-references to the relevant sections of the evidence as well as references to the 2005, 2006 and 2007 annual consolidated financial statements.

Chart 1

Evidence References for Provisions of O. Reg. 53/05

Relevant O. Reg. 53/05 Section	**Evidence Reference**	**Financial Statement Reference**
Deferral and Variance Accounts **5.** (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled “Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05” posted and available on the Ontario Energy Board website, that are associated with, (a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions; (b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1); (c) changes to revenues for ancillary services from the generation facilities prescribed under section 2; (d) acts of God, including severe weather events; and (e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. (2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices: 1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2	Ex. J1-T1-S1 Ex. J1-T2-S1 Ex. J1-T1-S1 Tables 1 - 11 Ex. J1-T2-S1 Tables1 - 3	Reflected as part of Regulatory Assets and Liabilities in the 2005, 2006 and 2007 consolidated balance sheet and accompanying note 6 (for years 2005 and 2006) and note 7 (for year 2007) to the consolidated financial statements

of section 2. 2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. (3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 percent applied to the monthly opening balance in the account, compounded annually. (4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the Board of Directors of Ontario Power Generation Inc. has determined should be placed in safe storage. (5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to, (a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and (b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 percent applied to the monthly opening balance in the account, compounded annually.		Interest on the monthly opening balance of the account is reflected in the balance sheet (as part of regulatory assets) and income statement (as part of interest expense).
5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.	Ex. J1-T1-S1 Ex. J1-T2-S1 Ex. J1-T1-S1 Tables 1, 4 Ex. J1-T2-S1 Tables1, 3	This deferral account was established in January 2007 and is reflected in the consolidated balance sheet and the accompanying note 7 to the 2007 consolidated financial statements.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 percent applied to the monthly opening balance in the account, compounded annually.		Interest on the monthly opening balance of the account is reflected in the balance sheet (as part of regulatory assets) and income statement (as part of interest expense).
5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between, (a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and (b) the liability arising from the current approved reference plan. (2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct.	Ex. J1-T1-S1 Ex. J1-T2-S1	
Nuclear development deferral account, transition **5.3** (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities: 1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act.* 2. Activities for obtaining any governmental license, authorization, permit or other approval.	 Ex. J1-T1-S1 Ex. J1-T1-S1 Table 7	 Reflected as part of regulatory assets in the consolidated balance sheet and accompanying note 6 to the 2006 consolidated financial statements and note 7 to the 2007 consolidated financial statements.

3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. (2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually.		
Nuclear development variance account **5.4** (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. (2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct.	Ex. J1-T1-S1	This is an account for going forward (after Board's first order) and there is no financial statement reference.
6. (2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act: 1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that, i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and ii. the revenues and costs are accurately recorded in the account.	Ex. J1-T1-S1 Ex. J1-T2-S1 Ex. J1-T3-S1 Ex. J1-T1-S1, Tables 1-11 Ex. J1-T2-S1, Tables 1-3	Reflected as part of regulatory assets in the consolidated balance sheet and accompanying note 7 to the consolidated financial statements.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.	Same as above	Same as above
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments, i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.	Ex. J1-T1-S1 Ex. J1-T2-S1 Ex. D1 and D2	Reflected as part of regulatory assets in the consolidated balance sheet and accompanying note 7 to the consolidated financial statements commencing in 2007.
4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that, i. the costs were prudently incurred, and ii. the financial commitments were prudently made.	Ex. J1-T2-S1 Ex. J1-T2-S1 Table 1 and Table 3	
5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were		Consolidated financial statements (balance sheet) and accompanying notes therein

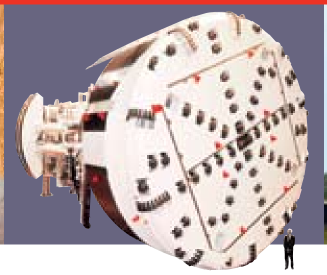
approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order: i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1. ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations. iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations. 6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to, i. capital cost allowances, ii. the revenue requirement impact of accounting and tax policy decisions, and iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2. 7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., i. return on rate base, ii. depreciation expense, iii. income and capital taxes, and	Ex. B1-T1-S1, Ex. G2-T2-S1 Ex. G2-T2-S1 Table 4 Ex. G2-T2-S1 Table 1 Ex. D1 and D2 Ex. J1-T2-S1 Ex. J1-T2-S1	Consolidated financial statements (income statement) and accompanying note 18 therein Consolidated financial statements (income statement) and accompanying note 18 therein Reflected as part of regulatory assets in the consolidated balance sheet and accompanying note 6 to the 2006 consolidated financial statements and note 7 to the 2007 consolidated financial statements. Reflected as part of regulatory assets in the consolidated balance sheet commencing 2007. (Note 7 of the

iv. fuel expense. 7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that, i. the costs were prudently incurred, and ii. the financial commitments were prudently made.		2007 consolidated financial statements) Reflected as part of regulatory assets in the consolidated balance sheet commencing 2007. (Note 7 of the 2007 consolidated financial statements)
8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.	Ex. H1-T1-S2	
9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.	Ex. G2-T2-S1	

1

LIST OF ATTACHMENTS

2005 Annual Report

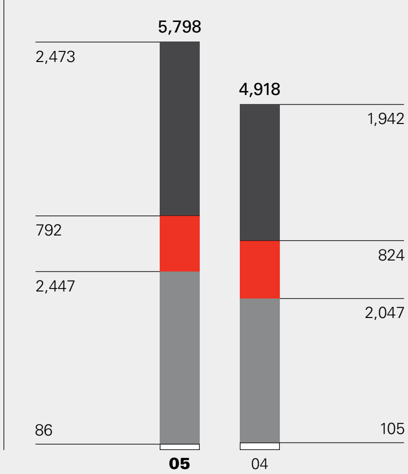


ONTARIOPOWER
GENERATION

OPG 2005

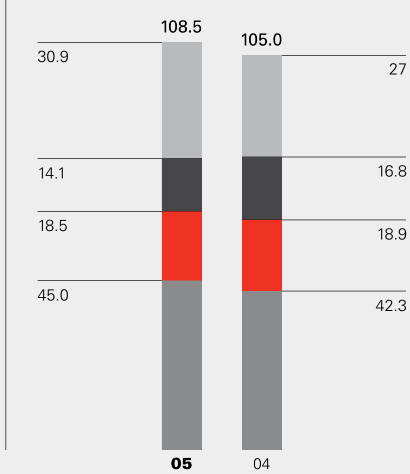
Revenue, Net of Market Power Mitigation Agreement Rebate and Revenue Limit Rebate
(millions of dollars)

- Unregulated Generation
- Regulated – Hydroelectric
- Regulated – Nuclear
- Other



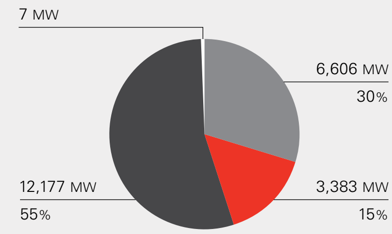
Electricity Production
(TWh)

- Unregulated Generation – Fossil-fuelled
- Unregulated Generation – Hydroelectric
- Regulated – Hydroelectric
- Regulated – Nuclear



In-Service Generating Capacity by Segment
22,173 MW

- Unregulated Generation
- Regulated – Hydroelectric
- Regulated – Nuclear
- Other



Years Ended December 31 (millions of dollars)	**2005**	2004
Earnings		
Revenue before Market Power Mitigation Agreement rebate and revenue limit rebate	**6,949**	6,072
Market Power Mitigation Agreement and revenue limit rebates	**(1,151)**	(1,154)
Fuel expense	**(1,297)**	(1,153)
Gross margin	**4,501**	3,765
Operations, maintenance and administration	**2,516**	2,594
Other expenses	**1,162**	1,209
Impairment of long-lived assets	**265**	–
Income tax expense (recovery)	**118**	(80)
Extraordinary item	**74**	–
Net income	**366**	42
Cash flow		
Cash flow provided by operating activities	**1,201**	226

Contents

Corporate Profile

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

In 2005, OPG generated 108.5 terawatt hours (TWh) of electricity.

OPG's electricity generating portfolio as of December 31, 2005, had a total in-service capacity of 22,173 megawatts (MW), which consisted of:

- three nuclear generating stations with a capacity of 6,606 MW
- five fossil-fuelled generating stations with a capacity of 8,578 MW
- 64 hydroelectric generating stations with a capacity of 6,982 MW and
- three wind generating stations (which includes a 50% interest in the Huron Wind joint venture) with a capacity of 7 MW.

In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own a 580 MW gas-fired generating station near Windsor, Ontario. In November 2005, OPG's Pickering A, Unit 1 nuclear reactor was returned to service, adding 515 MW to OPG's in-service generating capacity. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P.

Electricity Terms

One megawatt (MW) is one million watts. Megawatts are a measure of electricity supply capacity at a point in time.

One kilowatt (kW) is 1,000 watts; one gigawatt (GW) is one billion watts; and one terawatt (TW) is one trillion watts.

One kilowatt hour (kWh) is a measure of electricity demand per hour by customers. One kilowatt hour is the energy expended by ten 100 watt lights burning for one hour.

The average Ontario household uses approximately 1,000 kWh per month.

One megawatt hour (MWh) is 1,000 kWh; one gigawatt hour (GWh) is one million kWh; and one terawatt hour (TWh) is one billion kWh.

On the Cover

Nelly King, Technical Engineer/Officer, OPG Nuclear Waste Management; Feeder tube inspection, Pickering A, Unit 1; tunnel boring machine similar to the one being built to dig OPG's Niagara Tunnel; Atikokan fossil-fuelled generating station, which celebrated 20 years of operation in 2005.

Select List of Accomplishments

- The Pickering A, Unit 1 is returned to service after being laid up for nearly eight years.
- OPG's Darlington nuclear station is the best performing multi-unit nuclear station in Canada for the second consecutive year.
- Official groundbreaking for the start of construction of the Niagara Tunnel takes place in Niagara Falls.
- To help meet Ontario's electricity demand during one of the hottest summers on record, OPG's fossil-fuelled stations produce 62% more electricity than in the summer of 2004.
- OPG's coal-fired plants achieve their lowest acid-gas emission rates in OPG's history.
- OPG receives Gold Award from the Electrical and Utilities Safety Association for excellence in its safety management system and safety culture.

Message from Jake Epp, Chairman

The Board of Directors is committed to ensuring that OPG continues to move forward as a commercially focused, performance-driven company – one that is consistently open, transparent and accountable in its activities. In 2005, a number of steps were taken which helped strengthen these values, enhanced our governance capability and supported the company's commitment to excellence.

A New Mandate

In the summer of 2005, OPG reached a Memorandum of Agreement with our Shareholder, the Province of Ontario, regarding our role and responsibility as a power producer in Ontario. Under this agreement, OPG has a clear mandate to operate as a commercial company focused on a number of key activities and goals:

- generating electricity in a cost effective and efficient manner;
- continuously improving our nuclear performance and benchmarking that performance against the best CANDU operators internationally and in North America;
- expanding our hydroelectric capacity;
- operating our fossil-fuelled plants according to commercial principles until they are shut down as specified by the government's coal replacement policy.

In addition, OPG will maintain its high level of accountability and transparency and will operate under the highest standards of corporate governance, social responsibility, corporate citizenship and environmental stewardship.

Our new mandate gives focus and direction to our efforts and enables the Board – and others – to measure management's progress and hold them accountable for results.

Strengthening Our Governance Capability

OPG strengthened its governance capability in 2005 by adding two new directors. George Lewis and Peggy Mulligan were appointed to the Board of Directors. Mr. Lewis is Chairman and CEO, RBC Asset Management Inc. Mrs. Mulligan is Executive Vice President and Chief Financial Officer of Linamar Corporation. The OPG Board now has a full complement of 12 directors, with experience in engineering and project management; human resources; financial management and nuclear operations.

The Governance and Nominating Committee of the Board has also led the Board in implementing charters for the Board and each of its committees; developing position descriptions for each of the Committee Chairs; and supporting the continuing education of our directors. We also instituted a comprehensive orientation program for new directors joining the Board.

Open, Transparent and Accountable

OPG's governance, including our Board and Committee Charters, is described on the OPG web site. The web site also provides access to the Memorandum of Agreement with the Ontario government and shareholder directives. In 2005, OPG received two such directives under Section 108 of the Ontario Business Corporations Act. The first was to convert to gas our Thunder Bay coal-fired station; the second required us to amend our lease arrangement with Bruce Power.

New Leadership

In May 2005, Richard Dicerni ended his tenure as OPG's Acting President and CEO and OPG's new President and CEO, Jim Hankinson, was appointed by the Board.

On behalf of the Board, I would like to thank Richard Dicerni for his contribution to OPG and to welcome Jim Hankinson in his new role.

Message from Jim Hankinson, President and CEO

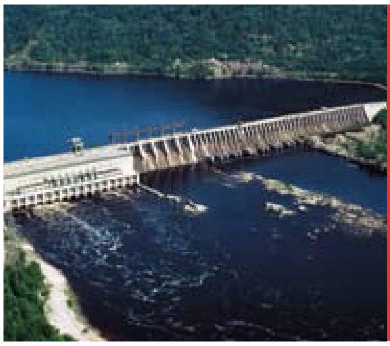
Ontario Power Generation is a performance-focused company. Performance is the yardstick we use to measure our progress; the impetus that drives our business; and the value that defines our success.

We are committed to achieving performance excellence through generation performance; asset improvement; supply expansion; and by operating in a cost effective and socially responsible manner that respects the needs of employees, the environment and communities.

In 2005, we made important strides in each of these areas while also improving our financial performance.

- Our generation performance was strong as we continued to develop and implement strategies to improve station productivity, enhance plant condition, and extend the operational lives of our stations.
- We expanded our production capacity by refurbishing and upgrading many of our generating stations – including the return to service of our Pickering A, Unit 1 nuclear reactor – as well as by launching new supply initiatives.
- We made a difficult but necessary commercial decision not to refurbish our two remaining laid-up nuclear units at Pickering A.
- We continued to achieve high levels of public safety, improved our workplace safety performance by reducing our employee injury rates, and maintained and enhanced our ongoing commitment to good governance, environmental stewardship and corporate citizenship.

In the summer of 2005, we negotiated a Memorandum of Agreement with our Shareholder, the Province of Ontario, which further sharpened our focus on these priorities and sets us on a clear direction for future growth and success.



The Otto Holden generating station. OPG manages its hydroelectric assets through prudent investments to enhance performance, increase capacity, and preserve their long-term capability. While hydroelectric production declined in 2005 due to lower water levels, the availability factor of these assets remained high at 92.4%.

The year was not without its challenges, which included a major, unplanned outage at the Pickering A nuclear station to inspect and maintain feeder tubes; the decision not to refurbish the two Pickering units; and the decommissioning of our Lakeview coal-fired station, as directed by the Ontario government.

In the following pages, I will be reviewing a number of OPG's achievements and related developments that took place during the past year. Overall, I am pleased with the progress we made in 2005. I recognize that our performance can continue to improve and am committed to making that happen with the support and contribution of all our employees.

Performing

Darlington Nuclear Generating Station

OPG's nuclear operations had an excellent year in 2005. Nuclear production increased by more than 6%, accounting for over 28% of the electricity consumed in Ontario. For the second year in a row, the Darlington station was Canada's best performing multi-unit nuclear generating station with a unit capability factor of 90.6%.

OPG Nuclear Performance: Key Results	2005	2004
— Production (TWh)	45.0	42.3
— Capability Factor (%)	83.8	80.4
— Nuclear Performance Index	76.4	70.7
— Forced Loss Rate (%)	5.35*	7.6
— All Injury Rate (per 200,000 hours worked)	1.06	1.25

*Lower number signifies improvement

Financial Performance

I am pleased to report that OPG's financial performance improved in 2005. Net income was $366 million or $1.43 per share compared to net income of $42 million or $0.16 per share in 2004. Earnings were positively affected by an increase in gross margin caused by higher average sales prices and increased nuclear and fossil-fuelled generation. The higher average sales prices we received in 2005 were primarily due to:

- higher average Ontario spot market prices resulting from stronger electricity demand during the very hot summer and the effect of higher natural gas prices; and
- the introduction of regulated prices and other related regulatory changes on April 1, 2005.

Our improved financial performance in 2005 was also partly due to decreased operations, maintenance and administration (OM&A) expenses resulting from the deferral in 2005 of costs related to the Pickering A, Unit 1 restart project as required by regulation. These OM&A reductions were partially offset by higher nuclear maintenance related to continuing improvements in station reliability; inventory write-offs as a result of the decision not to return Pickering A Units 2 and 3 to service; and increases in pension and other post employment benefit expenses.

Our 2005 earnings were negatively affected by impairment losses on OPG's Lennox gas and oil-fired generating station and on Units 2 and 3 of the Pickering A nuclear generating station. The impairment loss on the Lennox generating station was a result of the Province's decision to allow OPG to recover only its fixed operating costs through a contractual arrangement but not the carrying value of the station. The impairment loss on Units 2 and 3 at the Pickering A nuclear generating station resulted from the decision not to return these units to service.

OPG's Moderating Impact on Electricity Prices: As our financial performance improved in 2005, OPG continued to exercise a strong moderating influence on electricity prices paid by Ontario consumers. As a result of regulated rates and rebate mechanisms, OPG received an average price of 4.9 ¢/kWh in 2005 for the electricity produced from all of its generating stations. This price was considerably less than the weighted average hourly Ontario electricity price of 7.2 ¢/kWh received by other Ontario generators in 2005. From May 2002 to March 31, 2005 OPG rebated $4 billion under the former Market Power Mitigation Agreement (MPMA) to the benefit of Ontario's electricity users. In addition, for the balance of 2005, we will rebate some $739 million as a result of a revenue cap on much of our unregulated generation that went into effect on April 1, 2005.

The Lambton fossil-fuelled genererating station near Sarnia, Ontario. Production at OPG's fossil-fuelled stations increased by 14% in 2005. At the same time, acid gas emissions at these stations were the lowest in more than two decades.

Generation Performance

OPG generated 108.5 TWh of electricity in 2005 – an increase of 3.3% over the company's 2004 production of 105 TWh.

Nuclear: OPG's nuclear generation in 2005 rose to 45 TWh, compared to 42.3 TWh in 2004. For the second year in a row Darlington was the best performing multi-unit nuclear station in Canada with a unit capability factor of 90.6%. Pickering B achieved a unit capability factor of 77.7% compared to a 69.8% unit capability in 2004. Both stations performed at high levels of reliability during the cold winter and hot summer of 2005, with forced loss rates better than target. Our Pickering A station received a five-year operating licence from the Canadian Nuclear Safety Commission (CNSC) – the longest licence period for a nuclear power reactor that the CNSC grants to date.

Fossil: OPG's fossil-fuelled plants generated 30.9 TWh of electricity in 2005. This was nearly a 14% increase over the 2004 output. Contributing factors included higher electricity demand and improved station reliablity as evidenced by the lower Equivalent Forced Outage Rate of 15.9% achieved by these stations in 2005 compared to 18.7% in 2004. The strong reliability of our fossil-fuelled plants was also due to improved performance at our Nanticoke station and to the focused efforts of its employees and the employees at all our fossil facilities. OPG's fossil-fuelled plants function largely as "swing" resources during high demand periods. When demand reached record high levels during the past summer, these plants were producing on the hottest days up to 40% of OPG's generation.

Hydroelectric: While our hydroelectric output fell somewhat compared to 2004 due to lower water levels, the reliability of our hydroelectric stations continued to be very strong throughout the year, with an availability factor of 92.4%. These valuable assets deliver a steady supply of affordable, renewable power, and represent an important part of OPG's generation mix.

OPG employees prepare to install a new rotor on Unit 14 at the Beck 2 hydroelectric station. The work was part of an extensive nine-year project to replace and upgrade station equipment. Completed in the Spring of 2005, the project adds 194 MW to OPG's hydro-electric capacity.

Asset Improvement

Nuclear: OPG's higher nuclear output in 2005 is a direct result of our commitment to improve the performance of our nuclear stations – our top operational priority. Our strategy is to operate our nuclear assets efficiently and cost effectively while investing prudently to improve their reliability, predictability and lifespan. To this end, we continued to undertake in 2005 extensive and sustained programs in areas such as steam generator inspection and rehabilitation; feeder tube integrity; pressure tube remediation; and maintenance backlog reduction. As part of this strategy, we completed the first year of our 85/5 initiative at Pickering B – a major three-year program to improve the material condition and performance of that station. The station's goal is to achieve and maintain by 2007 an 85% capacity factor and a 5% forced loss rate – while reducing its average outage duration.

These and other improvement initiatives, many of which were implemented during the planned outages we performed on four of our nuclear units in 2005, are helping to maximize the life-expectancy of our nuclear fleet and contributed to the positive performance results achieved by our nuclear plants in the past year. To ensure that our nuclear plants continue to improve, we regularly measure them against the best plants in North America with particular focus on generation performance, operational excellence, backlogs and costs. By the end of the decade, decisions will be made on whether to extend the lives of OPG's nuclear units. Achieving consistently strong performance from our nuclear assets will help influence those decisions.

Fossil: While the Ontario government is committed to closing these plants over a period from 2007 to 2009, it has said it will not do so at the expense of supply reliability. Until they are shut down, however, we will continue to operate our coal plants in an efficient, reliable and environmentally responsible manner. Our goal is to ensure that the condition of our coal-fired plants is as good, if not better, on the day they close as it is today.

Hydroelectric: Our strategy with respect to our hydro-electric plants is to invest in them on an ongoing basis to enhance their performance, extend their service lives and reduce operational costs. Our improvements include replacing aging equipment, runner upgrades, station automation and innovative maintenance practices. A major milestone in this area was reached in 2005 with the completion of a nine-year rehabilitation initiative at the Beck 2 hydroelectric station near Niagara Falls, which added 194 MW to OPG's hydroelectric capacity. Additional hydroelectric upgrades between 2006 and 2015 will add another 150 MW to OPG's capacity.

These OPG employees are representatives of key groups involved in Pickering B's Spacer Location and Repositioning (SLAR) program. The SLAR program helps avoid pressure tube damage by preventing a nuclear reactor's pressure tubes from coming into contact for extended periods of time with its calandria tubes. By the end of 2005, about 83% of Pickering B's 1,565 fuel channels had been inspected using SLAR.

Improving

our assets to ensure reliability

Pickering A, Unit 1

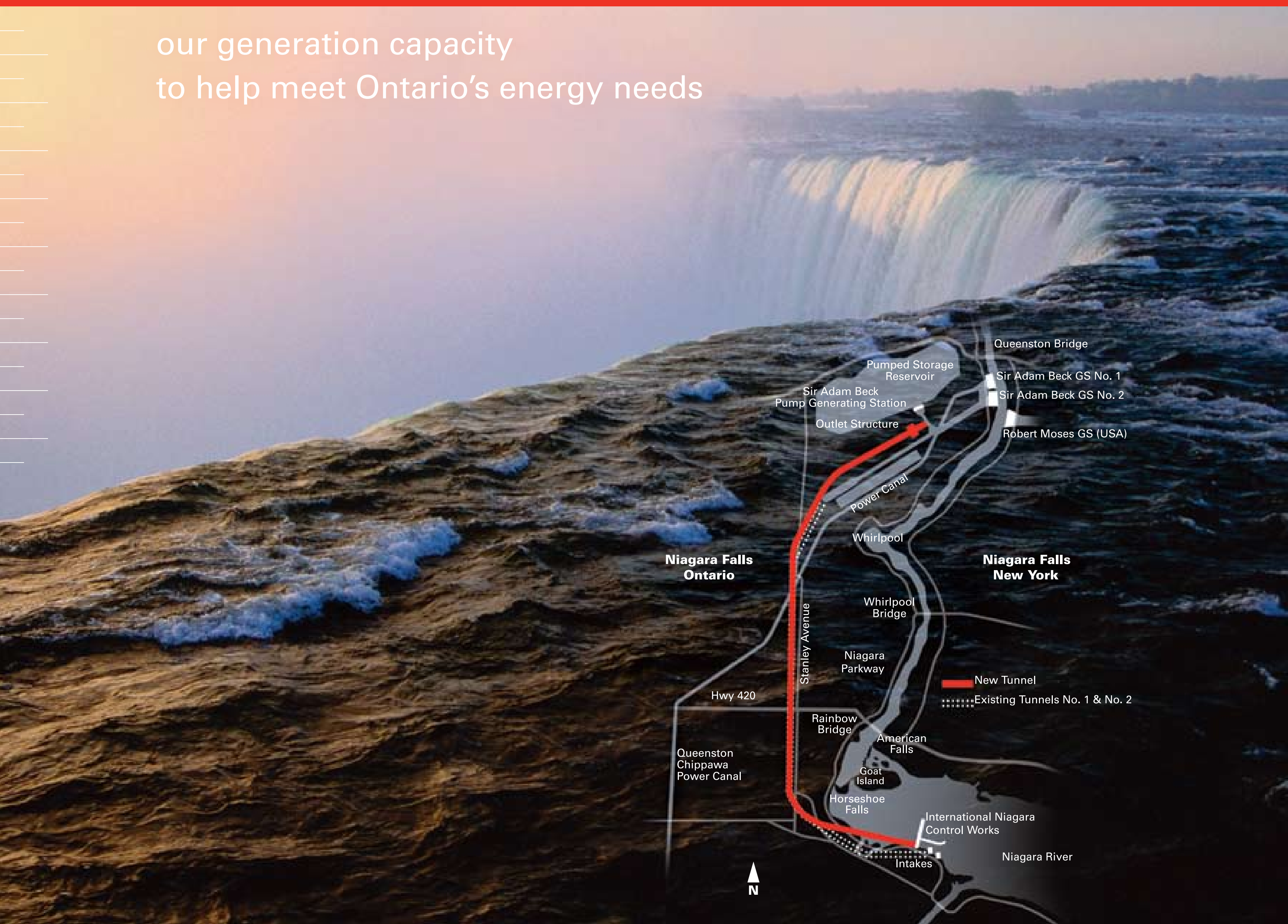
Standing before the reactor face of the Pickering A, Unit 1 nuclear reactor, two inspectors study the ends of the 390 pressure tubes that hold fuel for the reactor. OPG's successful return to service of Unit 1 in 2005 was one of the largest and most complex projects ever undertaken by the company. Off-line for almost eight years, the newly refurbished reactor adds to Ontario's electricity supply 515 MW of much-needed capacity that is virtually free of emissions that contribute to smog and global warming.

Unit 1 Refurbishment Achievements

- 2,879 peak employment
- 1.9 million hours worked
- 2.9 million individual parts installed
- 204 kilometres of new electrical cable
- 26,402 metres of pipe
- 24,500 individual tasks completed
- More than 5 million hours worked without a Lost Time Accident

Expanding

our generation capacity to help meet Ontario's energy needs



Niagara Tunnel Project

Ontario requires clean, reliable hydroelectric power for the future. Our mandate calls on us to help provide that power by developing and investing in Ontario's hydroelectric potential. The Niagara Tunnel is a major initiative on the road to this goal. In 2005, the OPG Board approved the total project and the award of the Design/Build contract to Strabag AG. Construction is currently underway. When complete, it will carry an additional 500 cubic metres per second of water from above Niagara Falls to OPG's Sir Adam Beck Generating Complex at Queenston, enabling more clean, renewable energy to be generated from the Niagara River while continuing to preserve the natural beauty of the Falls themselves.

Niagara Tunnel at a Glance

- 10.4 kilometres long
- $985 million estimated cost
- 350 peak employment
- 2009 completion date
- 90 years operating life
- 1.6 billion kilowatt hours of additional renewable energy per year

New Supply Initiatives

In addition to improving our performance, OPG is also investing in new generation capacity. Forecasts indicate that within the next several years Ontario could face electricity supply shortfalls without significant new generation initiatives. While OPG is not responsible for meeting all of Ontario's electricity supply needs, we have undertaken a number of new supply initiatives which help address this challenge. These initiatives will also help us to fulfill an important part of our mandate – which is to expand, develop and improve our hydroelectric generation capacity.

Our initiatives in this area include the construction launch of a new 10.4 kilometre tunnel to divert more water to the Beck hydroelectric stations. This initiative will increase the average annual energy output of these facilities by about 14% and is one of our most significant and exciting capital projects.

OPG also received Board approval to construct a new 12.5 MW hydroelectric generating station at Lac Seul in Northwestern Ontario. This construction is now underway.

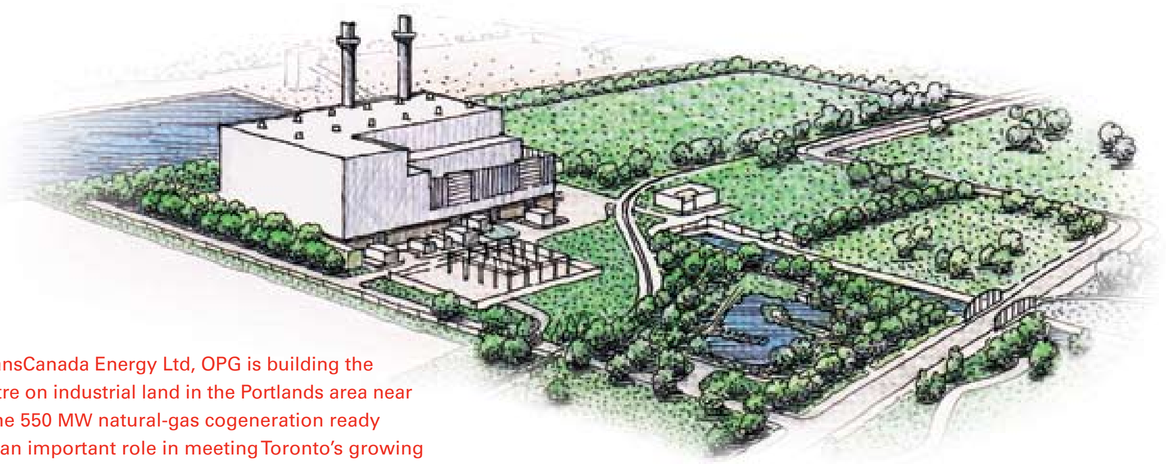
In addition to these projects, we are investigating options for the redevelopment of four hydroelectric plants in the Lower Mattagami River system in Northeastern Ontario. This initiative has the potential to contribute between 150 MW to 450 MW of additional clean, renewable hydroelectric power to the Province's electricity supply.

Complementing our hydroelectric initiatives, we are constructing, in partnership with TransCanada Energy Ltd., the Portlands Energy Centre – a 550 MW combined cycle natural-gas and co-generation capable generating facility located in downtown Toronto.

Under construction in Northwestern Ontario, the Lac Seul Generating Station will add 12.5 MW to OPG's hydroelectric capacity. The $47 million project is expected to be finished in 2007. The station will use much of the water currently being spilled at the adjacent Ear Falls hydroelectric station, increasing the overall efficiency of the site.

Finally, the Pickering A, Unit 1 restart – while one of our major refurbishment and asset improvement successes – was also our most notable new supply initiative, adding 515 MW of baseload power to our capacity. This massive and complex project confirmed OPG's ability to deliver a major capital project and represented a major accomplishment for the company in 2005. I want to thank all OPG employees who made this achievement possible.

Effective Cost Management: Cost management is a critical priority for OPG, and we employ a variety of cost management initiatives. Over the past few years, we reduced by some 20% our executive ranks and our corporate support groups. On the operating side, we are investing directly in our plants to improve their performance through programs such as the 85/5 initiative at Pickering B, upgrades to our hydroelectric stations and benchmarking programs to identify improvement opportunities. Changes in the way we blend different types of coal to fuel our Nanticoke station resulted in significant cost savings in 2005 and going forward.



In partnership with TransCanada Energy Ltd, OPG is building the Portlands Energy Centre on industrial land in the Portlands area near downtown Toronto. The 550 MW natural-gas cogeneration ready power plant will play an important role in meeting Toronto's growing energy needs. Ontario's Independent Electricity System Operator has estimated that the city will need 500 MW of new capacity by 2010, even with conservation initiatives being planned.

Employee-mentors at Nanticoke GS with co-op students. In 2005, Nanticoke received a "Passport to Prosperity" award from the Grand Erie Training and Adjustment Board. The award recognizes Nanticoke's efforts in providing co-op work opportunities for more than 350 high school students since 1991.

Operating to the Highest Corporate Standards

Safety Performance: Among our many priorities as a power provider, none is more important than ensuring the safety of the public and our employees at all times. This principle is rigorously applied at all our facilities.

OPG's nuclear plants operate according to strict regulatory standards and codes. In 2005, radiation emissions at both our Pickering and Darlington facilities continued to be a very small fraction of what Canadians receive annually from naturally occurring sources and much lower than that permitted by regulation. Since the Canadian nuclear power industry's inception over 40 years ago, no member of the public has ever been harmed as a result of radiation from our nuclear plants or waste management facilities. OPG's nuclear plants will continue to live up to these high standards.

We are equally committed to public safety at our other facilities. OPG's Public Water Safety Program is designed to help ensure that our hydroelectric stations and dams are operated safely and have the appropriate control measures in place to protect the public. Fundamental to this program is its focus on making the public in our site communities, including tourists, aware of the dangers associated with OPG's dams, hydroelectric stations and surrounding waterways. The uniqueness of each of our hydroelectric sites, the geographical diversity of the site communities themselves, and the large number of people who use the waterways where we operate make this a huge challenge. But it is one that we are committed to meeting.

With respect to employee safety, our goal is zero workplace injuries; and we continue to make progress toward meeting that ambitious target.

- Our 2005 All Injury Rate (AIR) of 1.33 injuries per 200,000 hours worked was better than the top quartile threshold (three year rolling average) set by the Canadian Electricity Association (CEA) and 13% better than our AIR performance in 2004.
- Our 2005 Accident Severity Rate (ASR) of 2.03 days lost per 200,000 hours was not as strong as our 2004 performance, but still well within the CEA's top quartile threshold (three year rolling average).

OPG's consistently strong workplace safety performance is a direct result of a vigorous safety culture that we have adopted at all our facilities. Employees are taught and encouraged to build safety behaviours into all aspects of their work and to take personal ownership of their own safety and that of their co-workers. This Internal Responsibility System is a cornerstone of our safety success.

Our safety commitment extends to our contractors, whom we expect to work to high safety standards, and we continued to implement programs requiring them to do so. We also continued our focus on promoting strong safety behaviours among young OPG employees and young people in the communities where we operate and across Ontario. In recognition of our efforts in building a strong safety management system and culture, the Electrical and Utilities Safety Association awarded OPG its Gold Award in 2005. OPG was the first recipient of this award.

Environment: As a major generating company with facilities across Ontario, we recognize that we have an impact on the environment and strive to minimize that impact at all times. Our coal-fired plants, for example, had the lowest acid-gas emission-rates in OPG's history even though they produced significantly more energy than in 2004. This strong and positive environmental performance was due in part to our sustained investments in clean air technology – including selective catalytic reduction equipment, combustion improvements, and the use of lower sulphur fuels.

(Left to right) John McCann, Manager, Lennox GS; OPG employee Liisa Blimkie, Ottawa-St. Lawrence Environment, Chemical and Safety Technician; and Leeds County Stewardship Council's Dwayne Struthers, with Peregrine falcon chicks at Charleston Lake. OPG staff worked with the Leeds County Stewardship Council, the Canadian Peregrine Foundation and the Charleston Lake Environmental Foundation to enable the falcons to be released into the wild.

Respecting

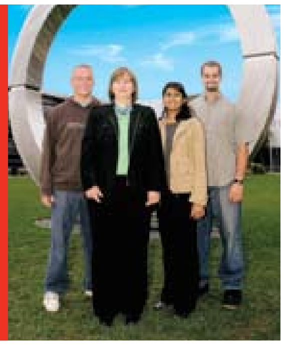
the needs of employees,
the environment
and the community

Darlington Mechanical Maintainers Skills Training

Mechanical maintainers at the Darlington nuclear station learn how to apply safe behaviours and procedures to protect themselves from workplace falls. Achieving zero workplace injuries is the ultimate goal of OPG's safety programs. The company's strong commitment to workplace safety was reflected in many notable safety initiatives and successes during 2005.

Select Accomplishments

- Continued top quartile safety performance within the electrical industry
- Continued operation of site-based Occupational Health & Safety Assessment Series 18001 safety management systems
- Launch of OPG-wide "Keep Your Promise" campaign, highlighting how our employees keep their promise to work safely
- Broadening of our Health & Safety Policy to include an emphasis on young worker safety within OPG, in communities where we operate, and across Ontario



Students at the University of Ontario Institute of Technology (UOIT). Located in Ontario's Durham Region, UOIT places a strong emphasis on science and technology education and career-focused learning. OPG is investing $10 million over a five year period in UOIT to contribute to the educational strength of Durham Region and help meet the need for highly-qualified, technically trained young employees.

For the third year in a row, OPG had no major impact spills. We also reported no moderate impact spills, continued to reduce our total amount of acid gas emissions, and planted an additional 326,000 native trees and shrubs in Ontario to help offset carbon dioxide emissions – for a total of 2.2 million trees planted since 2000 as part of our biodiversity commitment.

In addition, the environmental management systems at OPG's nuclear, hydroelectric and fossil plants were all recertified in 2005 under the internationally recognized ISO 14001environmental management standard. We also were recognized for our efforts in protecting and helping to restore the natural habitats that surround many of our generating facilities. As examples, the Darlington nuclear station was nominated for the Corporate Habitat of the Year Award by the Wildlife Habitat Council (WHC), and our Lennox generating station was nominated for the WHC's Rookie of the Year award. Currently, seven OPG sites are certified under the WHC for their wildlife habitat programs.

OPG also set aside $454 million in segregated funds to cover the future costs of decommissioning our nuclear plants and safely storing their used nuclear fuel. By the end of 2005, these funds totalled about $7 billion against a total present value liability of about $8.5 billion, helping to ensure that future generations of Ontarians will not be burdened with this cost.

Corporate Citizenship: OPG's corporate citizenship commitment embraces a wide range of endeavours. We communicate frequently with the communities where we operate through newsletters; reports to municipal councils; open houses; and door-to-door visits by employees to provide local residents with information about OPG. These outreach activities underscore our commitment to be an open, transparent and accountable corporate citizen.

We also continued to support many local initiatives in the communities where we operate. We focus on educational, environmental and community initiatives that enhance the quality of life in these communities. We provide assistance for student awards; engineering, science and technology based projects; youth amateur sports; biodiversity programs; community festivals; health and safety initiatives; and humanitarian efforts such as food banks and shelters. In 2005, OPG helped support 755 such initiatives in these and similar areas though our Corporate Citizenship Program.

In addition, OPG employees and pensioners contributed $1.8 million to the company's annual Charity Campaign, whose proceeds go to charities across Ontario. Our employees and pensioners also are active as volunteers, freely offering their time and services to community groups and causes.

Employees: This past year, I took the opportunity to travel across Ontario meeting personally with the men and women who run OPG's facilities. As I travelled from site to site talking to employees, I was continually impressed by their knowledge, experience, professionalism, and commitment.

OPG's 11,000 employees are the backbone of the company and a major reason for our success. Our goal is to be an organization whose performance and values consistently enable our employees to be engaged, productive and proud members of the OPG team. We made progress toward this goal in 2005. Employee engagement scores rose significantly in many parts of the company – thanks in part to the committed efforts of many OPG managers and supervisors.

In 2005 and early 2006, we also successfully renewed collective agreements with the two unions representing most of our employees – the Power Workers' Union and the Society of Energy Professionals. Both agreements are long-term in duration and were reached without the assistance of a mediator or arbitrator. The success of these negotiations reflects the mature and positive relationship that exists between OPG and its unions. These agreements also provide employees and OPG with the stability and flexibility we need to meet the challenges and opportunities that await us in the future. I have every confidence that our future is going to be bright, exciting and successful.

Management's Discussion and Analysis

Contents

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2005. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A is dated February 8, 2006.

Forward-Looking Statements

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, nuclear decommissioning and waste management, closure of coal-fired generating stations, pension and other post employment benefit ("OPEB") obligations, income taxes, spot market electricity prices, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, and the weather. Accordingly, undue reliance should not be placed on any forward-looking statement.

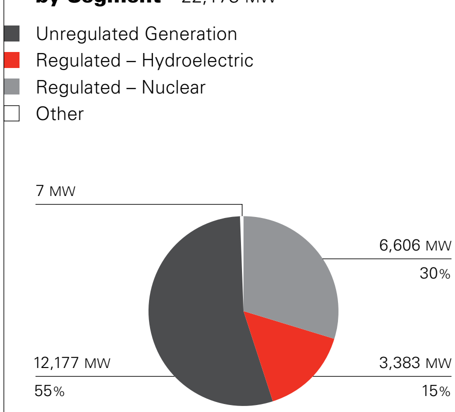
The Company

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was created under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

At December 31, 2005, OPG had 22,173 megawatts (MW) of in-service generating capacity. OPG's electricity generating portfolio consisted of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (which includes a 50 per cent interest in the Huron Wind joint venture). In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own a gas-fired generating station. All four units of the Pickering A nuclear generating station were laid up in 1997. Unit 4 was returned to service in 2003 and Unit 1 was returned to service in November 2005, adding 515 MW to OPG's in-service generating capacity. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. OPG continues to receive the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit. With the introduction of rate regulation, OPG revised its reporting segments to separately reflect the regulated and unregulated aspects of its operations. OPG's operating results are reported on a consolidated basis as well as by business segment. These segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation.

In-Service Generating Capacity by Segment 22,173 MW



Rate Regulation

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004,* which provides that, effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric and all of its nuclear facilities. This includes electricity generated from Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours (MWh) of production from the regulated hydroelectric facilities in any hour is $33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price. The regulated price received by OPG for production from the nuclear facilities is $49.50/MWh (4.95¢/kWh). These regulated prices were established by the Province, based on forecast production volumes and total operating costs, including the cost of capital and assuming an average five per cent return on equity. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will establish new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, they may be amended by the Province.

The regulation directed OPG to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions; changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes; changes to revenues assumed for ancillary revenues from the regulated facilities; acts of God (including severe weather events); and transmission outages and transmission restrictions. In addition, the regulation directed OPG to establish a deferral account for Pickering A return to service non-capital costs incurred on or after January 1, 2005.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station, Transition – Generation Corporation Designated Rate Options ("TRO") volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of $47.00/MWh (4.7¢/kWh). This revenue limit was originally established for a period of 13 months ending April 30, 2006. The Ontario Government ("Government") has recently announced the extension of the revenue limit for an additional three years. Starting May 1, 2006, the revenue limit will decrease to 4.6¢/kWh from the present limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. Revenues above these limits will be returned to the Independent Electricity System Operator ("IESO"), and the IESO will subsequently issue a rebate to consumers.

The implementation of regulated pricing for the generation from OPG's baseload hydroelectric and nuclear facilities, as well as the revenue limit on OPG's unregulated generating assets, replaced OPG's rebate obligations under the Market Power Mitigation Agreement effective April 1, 2005.

Highlights/Executive Summary

This section provides an overview of OPG's consolidated operating results. A detailed review of OPG's performance by business segment is included in a later section.

2005 Earnings

OPG's earnings improved in 2005 following the implementation of the regulatory changes which took effect April 1, 2005. Earnings from OPG's assets that are now regulated improved in 2005 compared to 2004 as a result of the introduction of regulated prices that reflect the projected production and costs of operations, including a cost of capital with an average five per cent return on equity, and the corresponding elimination of the Market Power Mitigation Agreement rebate. Earnings from OPG's unregulated assets also improved in 2005. While a significant portion of OPG's output from its unregulated assets was subject to the revenue limit, this limit was higher than the limit that was prescribed under the Market Power Mitigation Agreement.

Over the May 1, 2002 to March 31, 2005 period, OPG's earnings and liquidity were severely impacted by the requirement to rebate a significant portion of its revenues under the Market Power Mitigation Agreement. In total, the Market Power Mitigation Agreement rebate amounted to $4 billion over this period.

(millions of dollars)	**2005**	2004
Revenue		
Revenue before Market Power Mitigation Agreement and revenue limit rebates	**6,949**	6,072
Market Power Mitigation Agreement rebate	**(412)**	(1,154)
Revenue limit rebate	**(739)**	–
	5,798	4,918
Earnings		
Income (loss) before impairment of long-lived assets, income taxes and extraordinary item	**823**	(38)
Impairment of long-lived assets	**265**	–
Income (loss) before income taxes and extraordinary item	**558**	(38)
Income tax expense (recovery)	**118**	(80)
Income before extraordinary item	**440**	42
Extraordinary item	**74**	–
Net income	**366**	42
Electricity generation (TWh)	**108.5**	105.0
Cash flow		
Cash flow provided by operating activities	**1,201**	226

Net income for the year ended December 31, 2005 was $366 million compared to a net income of $42 million in 2004, an increase in earnings of $324 million. Income before income taxes and an extraordinary item for the year ended December 31, 2005 was $558 million compared to a loss of $38 million in 2004, an increase of $596 million. During 2005, OPG recorded a one-time extraordinary loss of $74 million to reflect the impact of adopting rate regulated accounting for income taxes effective April 1, 2005.

The following is a summary of the factors impacting OPG's results for 2005 compared to 2004, on a before-tax basis:

(millions of dollars – before tax)	
Loss before income taxes for the year ended December 31, 2004	**(38)**
Changes in gross margin	
Increase in electricity sales prices after Market Power Mitigation Agreement rebate and revenue limit rebate	662
Change in electricity generation by segment:	
Regulated – Nuclear	138
Regulated – Hydroelectric	(14)
Unregulated – Hydroelectric	(116)
Unregulated – Fossil-fuelled	62
Other changes in gross margin	4
	736
Decrease in Pickering A return to service OM&A expense due to deferral of non-capital costs in 2005 as a rate regulated asset	267
Increase in OM&A costs due to write-off of inventory, as a result of not returning Pickering A generating station Units 2 and 3 to service	(57)
Increase in nuclear maintenance and repairs	(101)
Increase in pension and other post employment benefit costs	(47)
Increase in earnings on nuclear fixed asset removal and nuclear waste management funds	68
Other net changes	(5)
Increase in income before income taxes and extraordinary item, excluding impairment of long-lived assets	**861**
Impairment of Pickering A generating station Units 2 and 3	(63)
Impairment of Lennox generating station	(202)
Income before income taxes and extraordinary item for the year ended December 31, 2005	**558**

Earnings for the year ended December 31, 2005 were significantly impacted by an increase in gross margin from electricity sales due primarily to higher average sales prices compared to 2004. The increase in OPG's average sales price was due in part to higher average Ontario spot market prices, which impacted revenue from OPG's unregulated generating assets, and the introduction of regulated prices and other related regulatory changes effective April 1, 2005. The higher spot market prices were primarily due to higher demand resulting from a prolonged period of hot summer weather and the effect on electricity prices of higher natural gas prices. Higher electricity generation in 2005 compared to 2004 due to higher demand and improved station performance also contributed to an increase in gross margin.

The increase in income during 2005 was also due to a decrease in operations, maintenance and administration ("OM&A") expenses resulting from the deferral of non-capital costs related to the Pickering A return to service project, commencing January 1, 2005, as required by a regulation pursuant to the *Electricity Restructuring Act, 2004*.

The favourable impact of these changes was partly offset by an impairment loss on OPG's Lennox generating station of $202 million before tax. It was determined that the Lennox generating station, as a relatively high variable cost plant, would not be able to recover its fixed operating costs and carrying value from the wholesale electricity market in the future. OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. OPG was subsequently advised by the Province during the first quarter of 2005 that it would continue to support OPG in negotiating an arrangement that would support the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the station. As a result of this change in circumstance, OPG recorded the impairment loss. OPG has since negotiated a contract with the IESO, pursuant to the market rules, to recover its operating costs for a one-year period ending September 30, 2006. The contract with the IESO has been submitted to the OEB for approval.

OPG recorded an impairment loss of $63 million during 2005 relating to Units 2 and 3 of the Pickering A nuclear generating station, as a result of OPG's decision not to proceed with the return to service of these units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. The impairment loss represented the carrying value, including construction in progress of these two units. In addition to the impairment loss for these two units, OPG recorded OM&A expenses of $57 million related to the write-off of inventory identified as excess or unusable, as a result of not returning Units 2 and 3 to service.

The Company also incurred higher nuclear maintenance and repairs in 2005 compared to 2004 related to continuing improvements in station reliability, and experienced an increase in pension and OPEB expenses primarily due to changes in economic assumptions.

Earnings in 2005 were also impacted by the effect of adopting rate regulated accounting for income taxes for the regulated segments of the business, and by changes in income tax positions. Effective April 1, 2005, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under this method, future income tax assets and liabilities associated with these segments are not recognized where those future income taxes are expected to be recovered in the regulated rates charged to customers in the future. As a result, during 2005, OPG did not record a future tax expense for the rate regulated segments of $157 million, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. As part of the transition, OPG also eliminated a net future income tax asset balance of $74 million relating to the rate regulated segments and recorded a corresponding one-time extraordinary loss.

During 2005, OPG recorded an income tax charge of $50 million to provide for a change in income tax liabilities related to certain income tax positions that the Company has taken in prior periods. OPG is responsible for making payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations.

In 2004, OPG's income tax expense was impacted by a reduction of $93 million in a valuation allowance for future income tax assets that had previously been established. This resulted in a reduction in the 2004 income tax provision, which did not recur in 2005.

Average Sales Prices

OPG's average sales prices by business segment, net of the revenue limit rebate for the period April 1, 2005 to December 31, 2005, and net of the Market Power Mitigation Agreement up to the inception of rate regulation on April 1, 2005 are as follows:

(¢/kWh)	**2005**	2004
Regulated – Nuclear[1]	**4.7**	4.1
Regulated – Hydroelectric[1]	**4.1**	4.1
Unregulated – Hydroelectric[2]	**5.2**	4.1
Unregulated – Fossil-fuelled[2]	**5.5**	4.2
OPG average price	**4.9**	4.1

1. During the period from April 1, 2005, electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh. During the same period, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.
2. During the period from April 1, 2005, 85 per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit based on an average price of 4.7¢/kWh.

OPG's average sales price was 4.9¢/kWh in 2005 compared to 4.1¢/kWh in 2004. OPG's average sales price was considerably less than the weighted average hourly Ontario electricity price of 7.2¢/kWh in 2005 as a result of regulated prices and the revenue limit rebate.

During 2005, OPG recorded $739 million related to the revenue limit rebate and $412 million related to the Market Power Mitigation Agreement rebate, compared to a Market Power Mitigation Agreement rebate of $1,154 million in 2004.

Electricity Generation

Electricity generated during 2005 from OPG's generating stations was 108.5 TWh compared to 105.0 TWh in 2004. The increase in generation was primarily a result of higher electricity demand and improved performance at OPG's fossil-fuelled and nuclear generating stations. The increase in generation was partly offset by a reduction in hydroelectric generation due to lower water levels.

OPG's results are impacted by changes in demand resulting from variations in seasonal weather conditions. The prolonged period of hot summer weather in 2005 resulted in a significant increase in the number of cooling degree days. The following table provides a comparison of heating and cooling degree days.

	2005	2004
Heating Degree Days[1]		
Total for year	**3,749**	3,751
Ten-year average	**3,704**	3,731
Cooling Degree Days[2]		
Total for year	**551**	233
Ten-year average	**356**	336

1. Heating Degree Days are recorded on days with an average temperature below 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport.
2. Cooling Degree Days are recorded on days with an average temperature above 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport.

Cash Flow from Operations

Cash flow provided by operating activities during 2005 was $1,201 million compared to $226 million in 2004, an improvement of $975 million. The favourable change in cash flow was primarily due to higher revenue and earnings compared to 2004 and lower rebate payments in 2005. The revenue limit rebates totalling $739 million relating to 2005 are not required to be paid until 2006. The favourable changes were partly offset by higher pension contributions during 2005.

Pickering A Unit 1 Return to Service

Major construction for the return to service of Unit 1 at the Pickering A nuclear generating station commenced in July 2004. The construction phase of the project was completed in July 2005, with the removal of Unit 1 from the guaranteed shutdown state. On September 26, 2005, Unit 1 was synchronized to the provincial electricity grid, sending electricity from the unit to Ontario consumers for the first time since December 1997.

In November 2005, OPG declared the unit to be commercially available and informed the IESO that the unit was available for dispatch into the Ontario market, adding 515 MW of baseload capacity in Ontario. The project represented a complex construction challenge, encompassing more than 1.9 million hours of work and almost 3,000 people at its peak.

During the major construction phase of Unit 1 at the Pickering A nuclear generating station, the schedule and cost to complete the project was impacted by the discovery of feeder pipe thinning in areas not previously identified. This resulted in the need to perform additional inspections and the replacement of a feeder pipe, which was not included in the original scope of the project and the cost estimate. In addition, feeder issues resulted in the shutdown of Unit 4 at the Pickering A nuclear generating station. Resources were diverted from Unit 1 to address the Unit 4 feeder issue and to complete other outage work, which also contributed to the extension of the Unit 1 project schedule. The costs related to the feeder inspection and replacement program and the schedule extension were approximately $20 million.

Total cumulative expenditures for the return to service of Unit 1 at the Pickering A nuclear generating station to December 31, 2005 were $994 million, excluding the impact on costs of the feeder inspection and replacement, and the diversion of resources to Unit 4.

Recent Developments

Bruce Power

In October 2005, the Province and Bruce Power announced an agreement to refurbish the Bruce A nuclear generating station. Under the agreement, Bruce Power will refurbish and restart Units 1 and 2, refurbish Unit 3 when it reaches the end of its current operational life and replace the steam generators in Unit 4. The Bruce A units were taken out of service between 1995 and 1998 after a decision by the former Ontario Hydro.

In 2001, Bruce Power entered into a lease arrangement with OPG relating to the Bruce A and B nuclear generating stations, which are owned by OPG. Some of the terms of the 2001 lease were altered in 2003 when British Energy left the partnership due to insolvency. Under the terms of the 2003 lease, a return to service of any of the Bruce A units would result in an annual lease payment of $25.5 million per unit (in 2002 dollars, escalated at the Consumer Price Index ("CPI")). As part of the agreement reached in October 2005 between the Province and Bruce Power, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to accept certain amendments to the lease agreement. These amendments included a change to the provisions regarding the transfer of Bruce Power's interest in the site and included a reduction of the annual lease payment for three of the four refurbished Bruce A units to $5.5 million per unit (in 2002 dollars, escalated at CPI), after the planned future refurbishments are completed. These changes to the lease agreement will impact OPG when Units 1 and 2 of the Bruce A nuclear generating station are returned to service, and when Unit 3 is refurbished at the end of its current operational life. Other changes to the existing arrangements were made to address Cameco Corporation's decision not to participate in the refurbishment of the Bruce A nuclear generating station.

Nuclear Waste Management Organization Report
In November 2005, the Nuclear Waste Management Organization ("NWMO") submitted its report and recommendation on the long-term care of Canada's used nuclear fuel to the Minister of Natural Resources. The NWMO presented the following four options: deep geological disposal in the Canadian Shield, storage at nuclear reactor sites, long-term storage at a centralized storage facility, and an adaptive phased management approach. The NWMO recommended a phased management approach whose key attributes are: ultimate centralized containment and isolation of used nuclear fuel in an appropriate geological formation; phased and adaptive decision-making that is flexible in order to accommodate changes as they occur over time; optional shallow storage at the central site prior to placement in the repository; continuous monitoring; provision for retrievability; and citizen engagement. The federal government will decide which management alternative should be followed.

Ontario Power Authority Recommendations on Electricity Supply Sources in Ontario
In December 2005, the Ontario Power Authority ("OPA") provided its recommendations to the Minister of Energy on options for the future development of Ontario's electricity system to 2025. The recommendations take into account the Government's priorities of: creation of a conservation culture, preference for renewable sources of energy, and replacement of coal-fired generation for environmental and health reasons. The OPA consulted with a number of key stakeholders, including OPG.

The report indicates that conservation and new renewable sources will more than meet all of Ontario's growth in demand for electricity by 2025. This would not, however, replace the loss of capacity from the retirement of other supply sources. To replace the loss of capacity from the retirement of other supply sources, gas-fired generation should play a targeted, but critical role, and the share of nuclear generation in Ontario's supply mix should be maintained at its current level by refurbishing existing units, rebuilding on existing sites and undertaking "new build" plants. The OPA's recommendations would increase the share of renewable sources in Ontario's supply mix, maintain the share of nuclear generation, and replace coal by increasing the share of gas-fired generation and renewable resources. The Government is currently evaluating the report and assessing its recommendations.

Earnings Outlook

OPG's improved earnings outlook is forecast to continue in 2006 as a result of the implementation of the regulatory changes which took effect April 1, 2005, and continued improvements in generating station performance. Earnings from the regulated business will continue to reflect the introduction of regulated prices related to most of OPG's baseload hydroelectric and all of its nuclear facilities. Earnings from the unregulated business will reflect the revenue limits applied to a significant portion of the output from OPG's unregulated assets, which are higher than the limit previously prescribed by the Market Power Mitigation Agreement.

In addition, OPG's future earnings are forecast to be impacted by a number of factors including the closure of its coal-fired generating stations and the impact of the regulated prices established by the OEB.

Vision, Core Business and Strategy

OPG's mandate is to cost effectively produce electricity from its diversified generation assets, while operating in a safe, open and environmentally responsible manner. OPG and its sole Shareholder, the Province, reached agreement on this mandate during the third quarter of 2005. OPG's mandate is comprised of the following strategic objectives:

- OPG will operate its existing nuclear, hydroelectric and fossil generating assets as efficiently and cost effectively as possible, within federal and provincial legislative and regulatory frameworks, and in a manner that mitigates the Province's financial and operational risk.
- OPG's key nuclear objective will be the reduction of risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units, while continuing to operate with a high degree of vigilance with respect to nuclear safety.
- OPG will seek continuous improvement in its nuclear generation business and internal services as well as benchmark its performance in these areas against CANDU nuclear plants world-wide and 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.
- 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-fuelled plants play in the Ontario electricity market.
- With respect to investment in new generation capacity, OPG's priority will be hydroelectric capacity. OPG will seek to expand, develop, and/or improve its hydroelectric generation capacity through expansion and redevelopment of its existing sites as well as the pursuit of new projects where feasible. OPG will undertake these investments through partnerships or on its own, as appropriate.
- OPG will operate in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility, corporate citizenship and environmental stewardship, taking into account the Government's coal replacement policy.

To accomplish its mandate and strategic objectives, OPG is focusing on the following four strategies: improving generating asset performance through production efficiencies and increased reliability; increasing its generating capacity; achieving excellence in corporate governance, safety, social responsibility, corporate citizenship and environmental stewardship; and effectively managing its costs.

Improving the Performance of Generating Assets

Nuclear Generating Assets

OPG's strategic objective is to operate the Darlington and Pickering A and B stations in a safe, efficient and cost effective manner, while undertaking prudent investments to improve their reliability and predictability. To achieve this objective, programs and initiatives have been implemented that will: continue to improve safety performance, reduce forced outages through improvements in equipment reliability, optimize planned outages, reduce maintenance backlogs, mitigate technological risks through comprehensive inspection and testing programs, focus on production unit energy costs, and address resource planning issues.

In August 2005, OPG decided to devote its resources and expertise to maximizing the performance of its ten existing nuclear units, rather than refurbish Units 2 and 3 at the Pickering A nuclear station. As a result, OPG has initiated the process of placing Pickering Units 2 and 3 in safe storage.

Hydroelectric Generating Assets

OPG's strategic objective is to optimize production from its existing hydroelectric generating assets. To continue to optimize production, programs are in place to: replace aging equipment, automate obsolete control equipment, accelerate runner upgrades, and improve availability through enhanced maintenance practices. These programs will result in increased capacity, extended service lives, and lower long-term operating and maintenance costs.

Fossil-Fuelled Generating Assets

OPG's strategic objective, taking into account the Government's coal replacement policy, is to maintain the productive capability of its coal-fired facilities, while continuing to operate them in an environmentally responsible manner. To achieve this objective, programs and initiatives are in place to: address the impacts of increased unit starts and stops, in part due to the role that the fossil-fuelled plants perform as intermediate and peaking facilities, ensure continued environmental compliance, and retain competent staff to continue to operate the units until their closure.

In October 2005, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to convert the Thunder Bay generating station to run on natural gas. Under the declaration, the Province will put in place appropriate cost recovery mechanisms covering initial capital and development expenditures, ongoing operating costs and an appropriate return to OPG. The cost recovery mechanisms are required to ensure that OPG is able to record the conversion costs as an asset. The project is expected to be complete by December 2007.

Increasing OPG's Generating Capacity

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generation capacity through expansion and redevelopment of its existing sites, as well as the pursuit of new projects where feasible. OPG will undertake these investments on its own or through partnerships.

Niagara Tunnel

In June 2004, OPG announced and the Government endorsed the decision to proceed with a new water diversion tunnel that will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara. This tunnel will allow the Beck generating facilities to utilize available water more effectively, and is expected to increase annual generation on average by about 1.6 TWh. OPG undertook an open, competitive and international process to select the successful contractor, with three pre-qualified companies submitting detailed design-build proposals in May 2005. Following approval by OPG's Board of Directors and cabinet approval to finance the project through the OEFC, OPG awarded a contract to Strabag AG in August 2005 to design and construct the 10.4 kilometre tunnel and associated facilities. The value of the design-build contract is approximately $600 million, with the total project expected to cost approximately $985 million.

Site preparation work started in September 2005. Blasting for the outlet canal started in December 2005 and is expected to continue through April 2006. Project completion is expected by late 2009. The project is currently on schedule and within the expected cost, with expenditures through December 2005 totalling $82 million.

Lac Seul

In December 2005, the OPG Board of Directors approved a $47 million project to construct a new 12.5 MW hydroelectric generating station on the English River, just east of OPG's existing Ear Falls generating station, which is 370 kilometres northwest of Thunder Bay, Ontario. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded to SNC Lavalin Power Ontario Inc. Construction commenced in January 2006, with the in-service date planned for the fourth quarter of 2007. As at December 31, 2005, approximately $3 million has been spent, which includes engineering, environmental approvals and geotechnical analysis.

Other Hydroelectric Projects

In addition to the Niagara tunnel and Lac Seul hydroelectric projects, OPG is exploring the feasibility of developing a number of potential hydroelectric projects in Northern Ontario.

Pickering A Unit 1 Return to Service

In November 2005, OPG declared Unit 1 at the Pickering A nuclear generating station to be commercially available and informed the IESO that the unit was available for dispatch into the Ontario market, adding 515 MW of baseload capacity in Ontario.

Portlands Energy Centre

OPG entered into a partnership with TransCanada Energy Ltd. ("TransCanada"), called Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle station on the site of the former R.L. Hearn generating station, near downtown Toronto. The generating station would help to meet the growing energy needs of Toronto's downtown core. The IESO identified, in its December 2005 18-month outlook, that Toronto faces rotating blackouts within the next two years unless urgent action is taken to install new power generation.

The Ministry of Energy has indicated that it will issue a separate directive to the OPA to procure up to 600 MW of generation for downtown Toronto. PEC intends to participate in this procurement process.

Excellence in Corporate Governance, Safety, Social Responsibility, Corporate Citizenship and Environmental Stewardship

Another of OPG's strategic objectives is to operate in accordance with the highest corporate standards, including, but not limited to the areas of corporate governance, safety, and sustainable development, taking into account the Government's coal replacement policy.

Corporate Governance

OPG's Board of Directors is made up of individuals with substantial expertise in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board has established a number of committees to focus on areas critical to the success of the Company.

OPG's corporate governance approach is to continually improve the policies and procedures used to direct and manage the corporation to enhance Shareholder value and ensure financial viability. OPG continues to implement initiatives to enhance corporate governance practices in line with existing Ontario Securities Commission ("OSC") regulatory requirements, with the objective of strengthening the organization. These initiatives are described in the Corporate Governance section on pages 50 to 53.

Safety

OPG is committed to achieving excellent safety performance, striving for continuous improvement with the goal of minimizing injuries. A primary objective is to achieve excellence in employee and public safety through the development and implementation of formal safety management systems, targeted risk mitigation programs, and a corporate commitment to safety. Continuous oversight and reporting provide management with information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. Oversight activities include internal and external safety management system audits, work protection code audits, and specific operational safety risk reviews. OPG also has a rigorous incident management system, which requires that all incidents, including near misses, be reported and investigated, and that corrective action plans are developed to prevent reoccurrences.

A contractor management program has been implemented to ensure that contractors contribute to our strong safety culture and maintain a level of safety equivalent to that of OPG employees. Initiatives are in place to address young worker safety issues within OPG and in the communities where we operate. A commitment to public safety is an important part in the operation of our generating stations, including standards established in the area of public waterways safety.

In 2005, OPG was the first and only recipient of the Electrical and Utilities Safety Association ("E&USA") Gold Award in recognition for effective safety management systems and a strong safety culture across the Company. This recognition followed a detailed assessment by the E&USA of OPG's safety management systems and interviews with staff from across the Company.

OPG measures its safety performance primarily through two performance indicators – Accident Severity Rate ("ASR") and All Injury Rate ("AIR"). The ASR is a measure of the number of days lost due to injuries. In 2005, OPG experienced 2.03 days lost per 200,000 hours worked. The AIR provides a measure of the frequency of injuries resulting in lost time or requiring medical treatment. In 2005, OPG experienced 1.33 injuries per 200,000 hours worked. OPG's ASR and AIR continue to be within the top quartile (2002 to 2004 average) of the Canadian Electricity Association.

Sustainable Development

OPG's sustainable development policy states that OPG will apply the principles of sustainable development to the generation and sale of electricity. OPG is committed to minimizing our impact on the environment; operating our facilities safely, reliably and responsibly; and being an engaged and productive member of our host communities. OPG's sustainable development activities can be divided into two categories: Environmental Stewardship and Social and Corporate Responsibility.

Environmental Stewardship

OPG's Sustainable Development Policy commits OPG to meet all applicable legislative requirements and voluntary environmental commitments. Other goals include integrating environmental factors into business planning and decision-making, applying the precautionary principle in assessing risks to human health and the environment, and maintaining environmental management systems ("EMSs") at our generating facilities consistent with the ISO 14001 standard. More information on OPG's emissions into the environment and compliance with environmental laws is included within the Risk Management – Environmental Risk section.

OPG utilizes a number of performance indicators to monitor environmental performance, including sulphur dioxide ("SO_2") and nitrogen oxides ("NO_X"). Acid gas (SO_2 and NO_X) emissions were 139 Gigagrams (Gg) in 2005 compared to 143 Gg in 2004. The reduction in emissions was primarily a result of improved performance from the selective catalytic reduction equipment installed at OPG's Nanticoke and Lambton fossil-fuelled generation stations and the use of lower sulphur fuels at OPG's fossil-fuelled stations, even though fossil-fuelled generation volumes were higher in 2005.

Social and Corporate Responsibility

Enhancing the quality of life in communities where companies operate is a corporate responsibility as well as a societal expectation. OPG is committed to being an active and good corporate citizen by strengthening relationships with the communities that OPG serves and those that host OPG's generating facilities. At the corporate level, as well as through the actions of employees, OPG plays a significant role in local communities by donating time and resources. The Corporate Citizenship Program provides financial and in-kind support to registered charities and not-for-profit environmental, educational and community organizations whose initiatives reflect OPG's values. Employees donate funds through an annual charity campaign and their time, expertise and energy through numerous personal acts of volunteerism.

Effective Cost Management

OPG's strategic objectives include operating its generating assets as cost effectively as possible, including the corporate and business unit support provided to those generating assets. OPG has commenced various initiatives aimed at better identifying and managing costs over and above those strategies aimed at improving generating asset performance. These initiatives include: an activity-based costing review of activities and processes in nuclear; benchmarking against industry-wide standards; a comprehensive review of project management intended to better integrate project planning, estimation, tracking of costs and schedule processes; ongoing review of opportunities for efficient fuel procurement, particularly relating to the fossil-fuelled generating stations; alignment of generating assets into technology-based businesses and full cost allocation review to improve management of these facilities; changes to vendor payment terms to improve cash flow; consolidation of functions supporting the restructured energy markets business; and key improvement initiatives aimed at streamlining information technology services and managing associated costs.

Capability to Deliver Results

Capital Resources and Liquidity

OPG's financial condition has improved following implementation of the regulatory changes which were introduced in 2005. In addition, in 2005, OPG secured dedicated financing for the Niagara tunnel and Thunder Bay generating station projects and additional long-term financial support from its Shareholder, the Province, in the form of long-term debt, on commercial terms and rates.

External financing consists primarily of a bank syndicated credit facility under which OPG issues commercial paper to fund its short-term requirements, and a number of financing arrangements held with OPG's Shareholder. OPG has the necessary working capital and financing resources to meet its obligations and commitments in 2006. OPG's liquidity is constrained by the revenue limit rebates on OPG's unregulated operations, which the Government recently announced would be extended for a period of three years.

Generating Assets

OPG continues to focus on maintaining and improving the performance of its generating stations.

OPG has increased the productive capacity of its hydroelectric stations, extended their service lives and lowered OM&A expenses through significant capital investment for the replacement of aging equipment, upgrades to runners and station automation, and enhanced maintenance practices. Programs are in place to further improve the hydroelectric stations, which already operate with high efficiency and reliability.

OPG is implementing initiatives that will improve the reliability and predictability of each of the nuclear generating stations. These initiatives are designed to address the specific technology requirements and risks at each of OPG's nuclear generating stations. The Darlington nuclear generating station is the most recently constructed station in OPG's nuclear fleet and operates with the highest reliability. The two operating units at the Pickering A nuclear station have recently been refurbished and are in good material condition. Programs are underway at the Pickering B nuclear generating station to mitigate technological risks and to improve its condition and performance. The performance of the Pickering B nuclear station has improved in 2005 compared to its performance in recent years.

OPG will continue to maintain the reliability and productive capacity of its coal-fired generating stations until their scheduled closure dates.

OPG has a number of potential sites for new generating asset development in Ontario. The completion of the decommissioning activity at OPG's Lakeview generating station will provide a brownfield site with the potential for development of additional generating capacity in the Greater Toronto Area.

Skilled Workforce

As of December 31, 2005, OPG had approximately 11,300 full-time employees. OPG has considerable experience in operating and maintaining generating stations through its trained and qualified technical employees. Due to an aging workforce, OPG's challenge is to attract and retain a skilled workforce to replace retiring employees. Approximately 34 per cent of the workforce was over the age of 50 at December 31, 2005. OPG has initiated a comprehensive resource and succession planning program to address issues related to the high percentage of employees eligible for retirement over the next five years, as well as those issues associated with the closure of the coal-fired generating stations.

The Company recently reached tentative agreements with the Power Workers Union, which are subject to membership ratification. The Company also recently renewed its labour agreement with the Society of Energy Professionals, extending the agreement to December 31, 2010. As of December 31, 2005, the Company had approximately 90 per cent of its regular labour forces covered by collective bargaining agreements.

Ontario Electricity Market Trends

In 2005, the Government implemented electricity sector reforms, which included electricity prices that better reflect the true cost of electricity and the termination of a financially unsustainable rebate. Effective April 1, 2005, the output from OPG's baseload hydroelectric and nuclear facilities became rate regulated, while output from its remaining hydroelectric facilities and its fossil-fuelled and wind generating stations remain unregulated. However, the majority of the generation output from these unregulated facilities is subject to a revenue limit.

Electricity demand is primarily impacted by weather and economic activity. Ontario's IESO reported that it faced a number of challenges maintaining the reliability of Ontario's bulk power system during the summer of 2005. Soaring temperatures brought significant demand and drought-like conditions limited hydroelectric generation, resulting in a continued strain on the power system. The IESO relied on extensive use of emergency control actions, including public appeals to reduce consumption, and voltage reductions. This occurred despite good performance and availability of Ontario generation and transmission facilities and the support from neighbouring markets. Ontario's peak electricity demand in 2005 of 26,160 MW represented an increase of 4.7 per cent over that of 2004. The expected peak demand in the summer of 2006, under normal weather conditions, is forecast by the IESO to be 25,917 MW. By 2015, Ontario's electricity peak demand, under normal weather conditions, is forecast to reach 26,900 MW and under extreme weather conditions, is forecast to approach 30,000 MW.

With respect to electricity supply, the IESO reported that increased supply brought into service in the fourth quarter of 2005 (515 MW from Unit 1 at the Pickering A nuclear generating station) and planned market enhancements in the first half of 2006 contribute to a more positive outlook for Ontario's overall supply adequacy picture over the next 18 months. The overall outlook for resource availability continues to indicate that for most weeks during this time frame, there are sufficient resources to meet demand, under the normal weather demand scenario. Under extreme weather conditions, the outlook identifies significant reliance on imports in many weeks, to meet demand. While the overall supply situation appears adequate, concerns remain in a number of areas within Ontario, particularly in the Greater Toronto Area, where the need for new supply and transmission facilities is particularly urgent.

In February, the IESO released its report titled, "The Ontario Reliability Outlook". The Outlook highlights the complexity of the changes and major infrastructure projects necessary to implement the Government's off-coal strategy. The IESO advised of the need for close coordination and continuous monitoring of progress and system impacts to maintain system reliability. The Outlook talks of the need for prudence in ensuring that Lambton and Nanticoke units are capable of operating beyond the currently specified dates for closure. OPG is committed to ensuring that its plants remain in as good operating condition as they are today, until the date the Company is required to close them by its Shareholder.

At the end of 2005, Ontario's existing installed generating capacity was 30,631 MW, a decrease of 533 MW over that of the previous year. This decrease was caused by the closure of OPG's Lakeview generating station, partially offset by the return to service of Unit 1 at OPG's Pickering A nuclear generating station. OPG's in-service capacity at the end of 2005 of 22,173 MW represented 72 per cent of Ontario's capacity. The IESO estimates that by 2015, approximately 12,850 MW of Ontario's electricity requirements will have to be met with new supply, refurbished generation or conservation measures. This estimate is consistent with that provided by the OPA in its report to the Minister of Energy on options for the future development of Ontario's electricity system to 2025.

In 2005, energy consumed in Ontario of 157.0 TWh represented an increase of 2.3 per cent over 2004 consumption. OPG's generating facilities produced 69 per cent of this amount. The IESO forecast for energy consumption in 2006 is 157.0 TWh.

Electricity prices typically peak when demand is at its highest, since high marginal cost peaking generating stations are required to meet that demand. Electricity prices also exhibit seasonal variations related to changes in demand. Ontario's weighted average hourly electricity price in 2005 of 7.2¢/kWh was significantly higher than in 2004. Changes in electricity prices have a significant impact on OPG's financial performance. This impact is significantly lessened by the application of fixed electricity prices for the output of assets subject to rate regulation and the effect of the revenue limit.

Fuel prices can have a significant impact on revenue and operating profits, both in terms of the underlying commodity price and the United States ("U.S.")/Canadian dollar exchange rate. During 2005, there were marked increases in the spot price for Appalachian and Powder River Basin coal, uranium, natural gas and oil, all of which are used to meet OPG's fuel requirements. OPG has a fuel hedging program that includes fixed price contracts for fossil and nuclear fuels. Foreign exchange derivatives are used to hedge exposure to anticipated U.S. dollar denominated purchases. As a result of volatile world energy markets, OPG expects this trend of increasing commodity prices to continue.

Business Segments

Prior to the introduction of rate regulation, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, included revenue and certain costs not allocated to its business segments. With the introduction of rate regulation, OPG changed the definition of business segments with effect from April 1, 2005 in recognition of the different economic characteristics of the Company's operations. The business segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. In addition, OPG continues to report a separate category, Other, which includes trading activities that previously comprised the Energy Marketing business segment, and revenues and certain costs neither attributable nor allocated to its business segments.

OPG has entered into various energy and related sales contracts with its customers to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included with electricity production revenues in each segment up to March 31, 2005, and in the Unregulated Generation segment after that date. Gains or losses on these hedging transactions are recognized in revenue over the term of the contract when the underlying transaction occurs.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations.

OPG's Regulated – Nuclear business segment includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. The arrangement includes lease revenue, interest income and revenue from engineering analysis and design, technical and other services. The Regulated – Nuclear business segment also includes revenue earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support. These earnings are included in the Regulated – Nuclear business segment since they were included in determining the regulated price for production from the nuclear facilities.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its baseload hydroelectric generating stations. The business segment includes electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated Generation Segment

OPG's Unregulated Generation business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations and from the hydroelectric generating stations not included in the Regulated – Hydroelectric segment. The Unregulated Generation business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Other

OPG earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

Key Generation and Financial Performance Indicators

To accurately reflect the measures that are critical to successful implementation of its strategy and achievement of its goals, OPG has expanded its disclosure of key performance indicators. These indicators are defined in this section and are discussed in both the Vision, Core Business and Strategy, and Discussion of Operating Results sections. Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, safety and environmental performance.

Nuclear Unit Capability Factor

OPG's nuclear stations operate as baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for external energy losses such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily impacted by planned and unplanned outages.

Fossil-fuelled and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's fossil-fuelled stations provide a flexible source of energy and operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations. OPG's hydroelectric stations operate primarily as baseload facilities and provide a reliable and low-cost source of renewable energy. A key measure of the reliability of the fossil-fuelled and hydroelectric stations is their ability to be available to produce electricity when called upon. EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the cost effectiveness of OPG's nuclear generating assets. It is a measure of the cost of producing a unit of electricity. Nuclear PUEC is defined as nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and the disposal of other low and intermediate level radioactive waste materials, divided by total energy produced.

Fossil-fuelled OM&A expense per MW

Since fossil-fuelled generating stations are primarily employed during periods of intermediate and peak demand, the cost effectiveness of these stations is measured by their total OM&A expenses, including allocated corporate costs, divided by total station nameplate capacity.

Hydroelectric OM&A expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses, including allocated corporate costs, divided by hydroelectric electricity generation.

Other Key Indicators

In addition to performance and cost effectiveness indicators, OPG has identified various social and environmental indicators. These indicators are discussed in the section titled Vision, Core Business and Strategy – Excellence in Corporate Governance, Safety, Social Responsibility, Corporate Citizenship and Environmental Stewardship.

Discussion of Operating Results by Business Segment

This section summarizes OPG's key results by segment for the years ended December 31, 2005 and 2004. Although the regulations pursuant to the *Electricity Restructuring Act, 2004* became effective commencing April 1, 2005, results for the quarters prior to April 1, 2005 have been reclassified according to the new business segment definitions. The prior period results from OPG's nuclear and hydroelectric generating stations that are now regulated have been reclassified into the Regulated – Nuclear and Regulated – Hydroelectric segments for comparative purposes. Similarly, results from OPG's unregulated generating stations have been reclassified into the Unregulated Generation segment. Accordingly, revenues reflect spot market prices received for electricity sales net of the Market Power Mitigation Agreement rebate up to the inception of rate regulation on April 1, 2005.

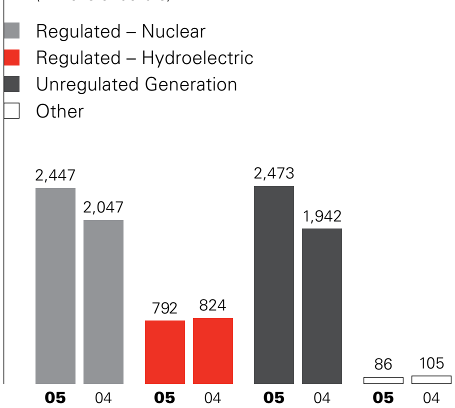
The operating results for the period prior to rate regulation reflect a significantly different economic environment from that introduced by rate regulation.

The following table provides a summary of revenue, earnings and operating statistics by business segment:

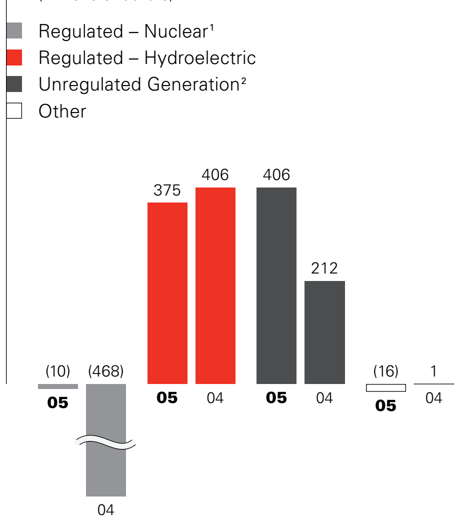
(millions of dollars)	2005	2004
Revenue, net of Market Power Mitigation Agreement rebate and revenue limit rebate		
Regulated – Nuclear	**2,447**	2,047
Regulated – Hydroelectric	**792**	824
Unregulated Generation	**2,473**	1,942
Other	**86**	105
	5,798	4,918
Income (loss) before interest, income taxes and extraordinary item		
Regulated – Nuclear	**(10)**	(468)
Regulated – Hydroelectric	**375**	406
Unregulated Generation	**406**	212
Other	**(16)**	1
	755	151
Electricity Generation[1] (TWh)		
Regulated – Nuclear	**45.0**	42.3
Regulated – Hydroelectric	**18.5**	18.9
Unregulated Generation – Hydroelectric	**14.1**	16.8
Unregulated Generation – Fossil-fuelled	**30.9**	27.0
Total electricity generation	**108.5**	105.0
Nuclear unit capability factor[2] (per cent)		
Darlington	**90.6**	88.2
Pickering A	**69.9**	75.7
Pickering B	**77.7**	69.8
Equivalent forced outage rate (per cent)		
Regulated – Hydroelectric	**1.2**	2.2
Unregulated Generation – Hydroelectric	**1.4**	1.4
Unregulated Generation – Fossil-fuelled	**15.9**	18.7
Nuclear PUEC ($/MWh)	**39.70**	39.20
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**4.17**	3.92
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**10.38**	7.68
Unregulated – Fossil-fuelled OM&A expense per MW ($000/MW)	**52.2**	46.0

1. Electricity generation is presented in accordance with OPG's business segments, with the exception of the Unregulated Generation segment, for which generation from hydroelectric and fossil-fuelled generating stations is shown separately.
2. Capability factors by industry definition exclude grid-related unavailability.

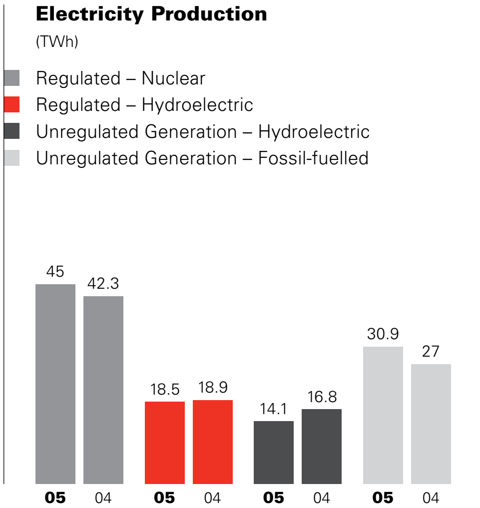
Revenue, Net of Market Power Mitigation Agreement Rebate and Revenue Limit Rebate
(millions of dollars)



Income (loss) Before Interest, Income Taxes and Extraordinary Item
(millions of dollars)



1. The Regulated – Nuclear segment includes the asset impairment loss of $63 million and inventory write-off of $57 million related to the Pickering A Nuclear generating station Units 2 and 3 in 2005.
2. Unregulated Generation segment includes the impairment loss of $202 million related to the Lennox generating station in 2005.



Regulated – Nuclear Segment

(millions of dollars)	2005	2004
Revenue, net of Market Power Mitigation Agreement rebate	**2,447**	2,047
Fuel expense	**115**	108
Gross margin	**2,332**	1,939
Operations, maintenance and administration		
Expenses excluding Pickering A return to service	**1,784**	1,611
Pickering A return to service	**4**	271
Depreciation and amortization	**374**	360
Accretion on fixed asset removal and nuclear waste management liabilities	**467**	445
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(381)**	(313)
Property and capital taxes	**31**	33
Income (loss) before the following:	**53**	(468)
Impairment loss	**63**	–
Loss before interest, income taxes and extraordinary item	**(10)**	(468)

Revenue

(millions of dollars)	2005	2004
Spot market sales, net of hedging instruments	**662**	2,090
Market Power Mitigation Agreement rebate	**(160)**	(374)
Regulated generation sales	**1,621**	–
Variance accounts	**(1)**	–
Other	**325**	331
Total revenue	**2,447**	2,047

Regulated – Nuclear revenue was $2,447 million for the year ended December 31, 2005 compared to $2,047 million in 2004. The increase in revenue was primarily due to higher sales prices related to the introduction of regulated rates effective April 1, 2005, which exceeded OPG's average spot market price net of the Market Power Mitigation Agreement rebate in 2004. Revenue also increased as a result of higher electricity generation of 2.7 TWh during 2005 compared to the prior year.

Electricity Prices

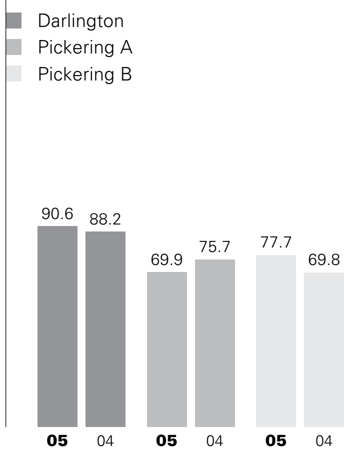
Since market opening on May 1, 2002, and prior to April 1, 2005, OPG was required under its generation licence issued by the OEB to comply with prescribed market power mitigation measures, including a rebate mechanism. Under the Market Power Mitigation Agreement, OPG had been required to pay a rebate to the IESO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for the amount of energy sales subject to the rebate mechanism for those generating stations that OPG continued to control. The IESO passed the rebate on to consumers. The amount of energy generated by OPG that was subject to the rebate mechanism was approximately 80.0 TWh on an annual basis.

Electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh since April 1, 2005. OPG's average sales price for the year ended December 31, 2005 was 4.7¢/kWh, after taking into account the regulated rate received from April 1, 2005 to December 31, 2005, and OPG's average spot market sales price, net of the Market Power Mitigation Agreement rebate for the first quarter of 2005. In 2004, OPG's average sales price after taking into account the Market Power Mitigation Agreement rebate was 4.1¢/kWh.

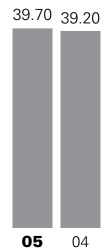
Volume

Total nuclear generation for the year ended December 31, 2005 increased to 45.0 TWh from 42.3 TWh in 2004. The increase in volume was primarily due to improved performance at the Pickering B and Darlington nuclear generating stations compared to 2004. Both stations experienced fewer unplanned outage days, and there were fewer planned outage days at the Pickering B generating station. The impact on volume from the return to service of Unit 1 at the Pickering A nuclear generating station in 2005, was largely offset by the impact of higher outage days for Unit 4 in 2005, primarily related to the shutdown of Unit 4 in April 2005 for inspection of feeder pipes. Unit 4 was returned to service in July 2005, after two feeder pipes were replaced.

Nuclear Unit Capability Factor
(%)



Nuclear PUEC
($/MWh)



The Darlington nuclear generating station's unit capability factor for 2005 of 90.6 per cent reflected continued strong performance. The reduction in outage days at the Pickering B nuclear generating station resulted in a significant improvement in its unit capability factor in 2005 to 77.7 per cent compared to 69.8 per cent in 2004. The unit capability factor for the Pickering A nuclear generating station decreased to 69.9 per cent in 2005 from 75.7 per cent in 2004, as a result of the Unit 4 outage for inspection and replacement of feeder pipes.

Fuel Expense

Fuel expense for the year ended December 31, 2005 was $115 million compared to $108 million in 2004. Fuel expense for the nuclear generating stations was only marginally impacted by the changes in generation volumes in 2005 compared to 2004 due to the low marginal cost nature of nuclear generation.

Operations, Maintenance and Administration

OM&A expenses, excluding those related to the Pickering A return to service initiative, were $1,784 million for the year ended December 31, 2005 compared to $1,611 million in 2004, an increase of $173 million. As part of OPG's objective to improve the performance of its nuclear generating stations, the Company has committed additional resources in an effort to maximize the operating availability and reliability of these stations. OM&A expenses for nuclear maintenance and repairs increased by $101 million compared to 2004. These expenditures related to ongoing maintenance costs to address plant condition, regulatory requirements, and improvement projects. OM&A expenses also increased in 2005 compared to 2004 due to the write-off of $57 million of excess inventory as a result of the decision not to return Pickering A generating station Units 2 and 3 to service.

In addition, pension and OPEB costs increased by $36 million compared to 2004, primarily the result of changes in economic assumptions related to discount rates. The impact of these increases in expense was partly offset by reductions in other costs.

Nuclear PUEC in 2005 increased to $39.70/MWh compared to $39.20/MWh in 2004 primarily as a result of the additional expenditures on maintenance and repairs, and the increase in pension and OPEB costs.

Pickering A Return to Service

Effective January 1, 2005, in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004,* OPG established a balance sheet deferral account for non-capital costs associated with the return to service of Pickering A nuclear generating station units. These deferred costs will be charged to operations in subsequent periods in accordance with the terms of the above referenced regulation. The regulation requires the OEB to ensure recovery of any balance recorded in the deferral account over a period not exceeding 15 years. This approach is consistent with one of the objectives of rate regulation, which is to ensure that present customers are not burdened with costs incurred for the benefit of future customers, and with generally accepted accounting principles in that the financial effects of regulation can lead to the recording of assets and liabilities that would not otherwise be recognized by a non-rate-regulated entity. Amortization of this deferral account began during the fourth quarter of 2005 on the date of the return to commercial service of Unit 1 of the Pickering A nuclear generating station. The amortization of $4 million was charged to OM&A expense.

As a result of the regulation, non-capital costs related to the Pickering A return to service initiative were excluded from OM&A during 2005, with the exception of that portion amortized in 2005 due to the return to service of the Pickering A generating station Unit 1. Had these expenditures not been deferred, OM&A expense of $258 million would have been recognized in 2005 compared to $271 million last year.

Impairment of Long-Lived Assets – Pickering A Generating Station Units 2 and 3

As a result of the decision not to proceed with the return to service of Pickering nuclear generating station Units 2 and 3, the Company recorded an impairment loss of $63 million in the second quarter of 2005 related to the carrying amount of these two units, including construction in progress. OPG continues to assess the need to provide for additional charges as a result of the decision not to proceed with the return to service of Units 2 and 3, including the cost associated with preparing the units for safe storage, the impact on cost estimates for asset retirement obligations, and any other exit costs. OPG completed a preliminary assessment of additional charges during the fourth quarter of 2005.

Depreciation and Amortization

Depreciation and amortization expense for the year ended December 31, 2005 was $374 million compared to $360 million in 2004. The increase was primarily due to fixed asset additions at the Pickering B and Darlington nuclear generating stations. In addition, the return to commercial service of Unit 1 at the Pickering A nuclear generating station in November 2005 resulted in an increase in depreciation expense of $4 million in 2005, and will initially add approximately $21 million to annual depreciation expense thereafter. These increases were partially offset by an extension of the remaining service life of Unit 4 at the Pickering A nuclear generating station. During the fourth quarter, as a result of the return to commercial service of the Pickering A generating station Unit 1, OPG extended, for purposes of calculating depreciation, the remaining service life of the Pickering A generating station Unit 4 to 2021, consistent with the expected service life of Unit 1. This reduces depreciation expense by approximately $16 million annually over the period to 2017, excluding the impact of future asset additions. OPG is in the process of reviewing the remaining service lives of its other nuclear generating stations.

Accretion

OPG records the present value of its future costs for fixed asset removal and nuclear waste management as a long-term liability. This liability is discussed in Note 9 to the consolidated financial statements as at and for the year ended December 31, 2005. Accretion expense reflects the change in the present value of this liability since the end of the prior period. This expense is impacted by factors such as any changes in the estimate of the amount of the future liability for fixed asset removal and nuclear waste management, any changes to the discount rate used to determine the present value, and the change in the present value due to the passage of time.

Accretion expense for 2005 was $467 million compared with $445 million in 2004. The increase in the accretion expense was due to the higher liability base compared to last year as a result of the increase in the present value of the liability due to the passage of time.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG is responsible for the ongoing long-term management and disposal of radioactive waste materials and used fuel resulting from operations and future decommissioning of its nuclear generating stations. OPG's obligations relate to the Pickering and Darlington nuclear plants that are operated by OPG, as well as the Bruce A and B nuclear plants that are leased by OPG to Bruce Power.

In order to fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund (the "Nuclear Funds"), which are funded by OPG in accordance with the Ontario Nuclear Funds Agreement ("ONFA"). The Used Fuel Fund is intended to fund future expenditures associated with the disposal of highly radioactive used nuclear fuel bundles. The Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities, which OPG records as long-term investments at their amortized cost. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements. The balance of the Nuclear Funds on an amortized cost basis, as at December 31, 2005, was $6,788 million compared to $5,976 million as at December 31, 2004. This balance is referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements.

Under ONFA, the Province guarantees the annual rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") over the long term. OPG recognizes the committed return on the Used Fuel Fund and includes it in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the assets, which includes realized and unrealized returns, is due to or from the Province. Since OPG accounts for the investments in the Nuclear Funds on an amortized cost basis, the amount due to or due from the

Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At December 31, 2005, the Used Fuel Fund included an amount due to the Province of $4 million (2004 – $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the consolidated financial statements, at December 31, 2005, there would be an amount due to the Province of $306 million (2004 – $156 million). In addition, under ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Under ONFA, the Decommissioning Fund has a long-term target rate of return of 5.75 per cent per annum. OPG bears the risk and liability for cost estimate increases and fund earnings associated with the Decommissioning Fund. At December 31, 2005, based on the estimate of costs to complete under the current approved ONFA Reference Plan (currently the 1999 Reference Plan), the Decommissioning Fund was fully funded on a market value basis and on an amortized cost basis. When the Decommissioning Fund is overfunded on an amortized cost basis, OPG will limit the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the amortized cost balance of the Decommissioning Fund would equal the cost estimate of the liability based on the 1999 Reference Plan. These realized gains may be recognized in subsequent periods provided the Decommissioning Fund balance declines below the then currently approved cost estimate.

At December 31, 2005, the Decommissioning Fund asset value on an amortized cost basis was $4,099 million compared to a market value of $4,583 million, the difference representing net unrealized gains of $484 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the then current ONFA Reference Plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to the remaining 50 per cent of such surplus. Any overfunding of the liability is payable to the Province on termination of the Decommissioning Fund. Therefore, the accounting for this overfunded position requires an adjustment to the amortized cost value of the assets in the Decommissioning Fund. This adjustment reduced the value of the assets by $7 million, to equal the value of the liabilities as defined by the current approved ONFA reference plan. If the investments in the Decommissioning Fund were accounted for at fair market value in the consolidated financial statements at December 31, 2005, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $484 million (2004 – $249 million).

Realized earnings on the Nuclear Funds for the year ended December 31, 2005 were $381 million compared to $313 million for 2004, an increase of $68 million. The increase in earnings in 2005 was largely due to higher earnings in the Used Fuel Fund as a result of a larger asset base due to growth through a combination of earnings and contributions, and a higher Ontario CPI compared to 2004.

Regulated – Hydroelectric Segment

(millions of dollars)	**2005**	2004
Revenue, net of Market Power Mitigation Agreement rebate	**792**	824
Fuel expense	**254**	255
Gross margin	**538**	569
Operations, maintenance and administration	**77**	74
Depreciation and amortization	**68**	71
Property and capital taxes	**18**	18
Income before interest, income taxes and extraordinary item	**375**	406

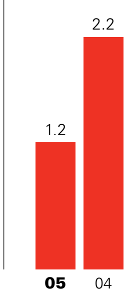
Revenue

(millions of dollars)	**2005**	2004
Spot market sales, net of hedging instruments	**260**	971
Market Power Mitigation Agreement rebate	**(65)**	(194)
Regulated generation sales[1]	**558**	–
Variance accounts	**2**	–
Other	**37**	47
Total revenue	**792**	824

1. Regulated generation sales includes revenue of $210 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during 2005.

Regulated – Hydroelectric revenue was $792 million for the year ended December 31, 2005 compared to $824 million in 2004. The decrease in revenue was primarily due to lower electricity generation in 2005 of 0.4 TWh compared to 2004, and marginally lower average prices in 2005 due to the introduction of regulated rates and related changes effective April 1, 2005.

Regulated – Hydroelectric EFOR
(%)



Regulated – Hydroelectric OM&A per MWh
($/MWh)

Electricity Prices
The average sales price is based on the fixed price of 3.3¢/kWh for generation up to 1,900 MWh in any hour, and the spot electricity market price for generation above this level. The average price for the year ended December 31, 2005, was 4.1¢/kWh, after taking into account the regulated price from April 1, 2005 to December 31, 2005, and OPG's average spot market sales price, net of the Market Power Mitigation Agreement rebate for the first quarter of 2005. After taking into account the Market Power Mitigation Agreement rebate, the average spot market sales price for the year ended December 31, 2004 was 4.1¢/kWh.

Volume
Electricity sales volume for the year ended December 31, 2005 was 18.5 TWh compared to 18.9 TWh in 2004. During the period from April 1, 2005 to December 31, 2005, electricity generation of 2.8 TWh related to production levels above 1,900 MWh in any hour. The decrease in generation volume was due to decreased water flows on the Niagara and St. Lawrence rivers during 2005 compared to 2004.

Equivalent forced outage rate (EFOR) for the Regulated – Hydroelectric stations was 1.2 per cent in 2005 compared to 2.2 per cent in 2004. The low EFOR in 2005 and 2004 reflect the high reliability of these stations.

Variance Accounts
OPG is required under a regulation pursuant to the *Electricity Restructuring Act, 2004* to establish variance accounts to capture the impact of certain items during the interim period. One of these items that applies specifically to the Regulated – Hydroelectric segment requires OPG to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions. OPG's liability as at December 31, 2005 of $4 million reflected the fact that water conditions were favourable to those forecast. In addition, OPG recorded an asset of $6 million to reflect the fact that actual ancillary revenues were lower than those forecasted.

Fuel Expense
Fuel expense for the year ended December 31, 2005 was $254 million compared to $255 million in 2004. OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense.

Operations, Maintenance and Administration
OM&A expenses for the year ended December 31, 2005 were $77 million compared to $74 million in 2004. OM&A expense per MWh for 2005 increased to $4.17/MWh from $3.92/MWh in 2004 primarily due to the lower generation in 2005 as a result of the reduction in water flows.

Depreciation and Amortization
Depreciation and amortization expense for the year ended December 31, 2005 was $68 million compared to $71 million in 2004.

Unregulated Generation Segment

(millions of dollars)	2005	2004
Revenue, net of Market Power Mitigation Agreement and revenue limit rebates	**2,473**	1,942
Fuel expense	**928**	790
Gross margin	**1,545**	1,152
Operations, maintenance and administration	**594**	576
Depreciation and amortization	**276**	302
Accretion on fixed asset removal	**9**	8
Property and capital taxes	**54**	38
Restructuring	**4**	16
Income before the following:	**608**	212
Impairment loss	**202**	–
Income before interest, income taxes and extraordinary item	**406**	212

Revenue

(millions of dollars)	2005	2004
Spot market sales, net of hedging instruments	**3,255**	2,417
Market Power Mitigation Agreement rebate	**(187)**	(586)
Revenue limit rebate	**(739)**	–
Other	**144**	111
Total revenue	**2,473**	1,942

Unregulated Generation revenue was $2,473 million for the year ended December 31, 2005 compared to $1,942 million in 2004. The increase in revenue was primarily related to higher average sales prices and higher electricity generation in 2005 compared to 2004. In addition, IESO system constraints related revenue was higher in 2005 compared to 2004.

Electricity Prices

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, was subject to a revenue limit based on an average price of 4.7¢/kWh after April 1, 2005. Prior to April 1, 2005, OPG received the average electricity spot market sales price, but revenue was reduced by the Market Power Mitigation Agreement rebate.

OPG's average sales price for its unregulated generation for the year ended December 31, 2005 was 5.4¢/kWh, after taking into account the impact of the revenue limit rebate. The average spot market sales price for the year ended December 31, 2004 was 4.2¢/kWh, net of the Market Power Mitigation Agreement rebate.

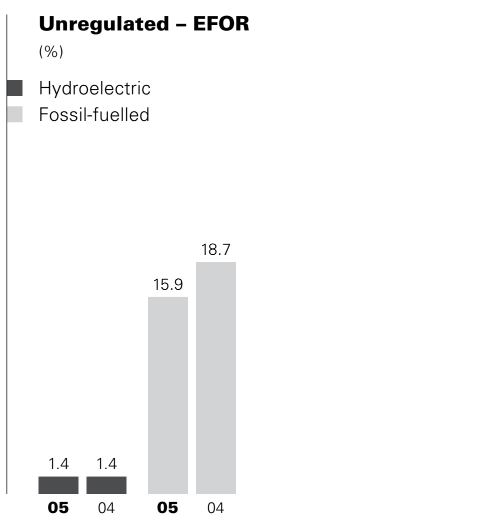
The higher prices during the year ended December 31, 2005 compared to 2004 were due to higher average spot market sales prices during 2005 and the replacement of the Market Power Mitigation Agreement rebate with the revenue limit effective April 1, 2005.

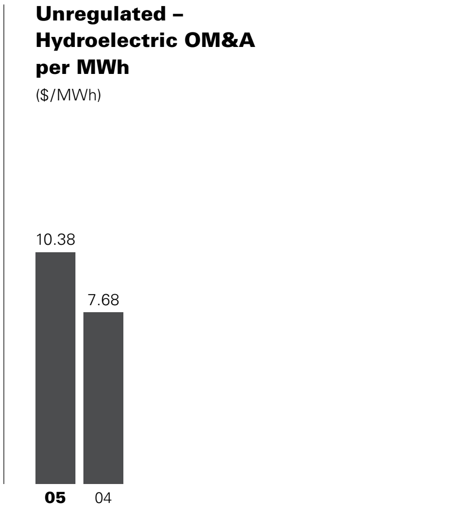
During the period June to December 2005, the Ontario market experienced significantly higher spot market prices which arose from the interaction of a variety of factors. A prolonged period of hot summer weather resulted in increased demand for electricity which required the use of higher marginal cost gas-fired generation. The cost of this gas-fired generation was in turn influenced by higher North American natural gas prices. Also, lower water levels reduced the energy supply from lower marginal cost hydroelectric resources, thereby further increasing the energy to be supplied by higher marginal cost sources. Higher natural gas prices throughout the fall of 2005 continued to affect electricity prices compared to the same period in 2004.

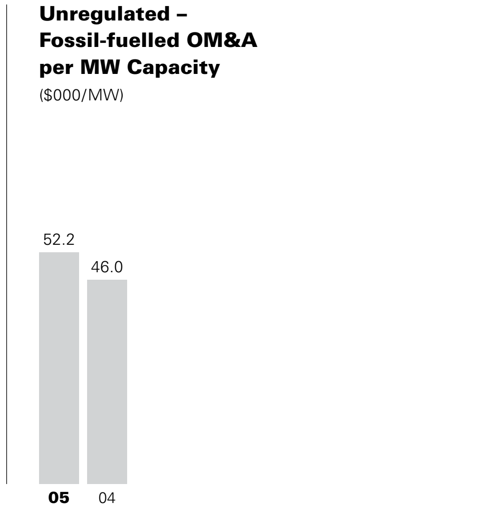
Volume

Electricity sales volume for the year ended December 31, 2005 was 45.0 TWh compared to 43.8 TWh in 2004. Generation from the fossil-fuelled stations increased by 3.9 TWh in 2005 compared to 2004 to meet the higher demand in Ontario. Strong performance from the fossil-fuelled generating stations during 2005 enabled OPG to generate electricity in response to this increased demand. The increase was partly offset by a reduction in volumes of 2.7 TWh from the unregulated hydroelectric facilities due to lower water levels, especially in the Ottawa and northeast regions.

EFOR for the hydroelectric stations remained at 1.4 per cent for both 2005 and 2004, reflecting the continued high reliability of these stations. EFOR for the fossil-fuelled stations decreased to 15.9 per cent in 2005 from 18.7 per cent in 2004, primarily as a result of improved reliability at OPG's Nanticoke generating station.







Fuel Expense

Fuel expense for the year ended December 31, 2005 was $928 million compared to $790 million in 2004. Fuel expense for the Unregulated Generation segment includes the cost of fossil fuels and charges on gross revenue derived from the hydroelectric generating stations. The increase in fuel expense during the 2005 period was primarily due to the higher production from the fossil-fuelled generating stations.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2005 were $594 million compared to $576 million in 2004. OM&A increased during 2005 as a result of increased maintenance work at OPG's hydroelectric and fossil plants and higher pension and OPEB expenses, partially offset by lower costs from closing the Lakeview generating station.

OM&A expense per MWh for the hydroelectric stations increased to $10.38/MWh in 2005 from $7.68/MWh in 2004 primarily as a result of lower generation in 2005. The higher OM&A expenses also contributed to the increase in OM&A expense per MWh.

OM&A expense per MW ($/MW) for the fossil-fuelled stations increased to $52,200/MW in 2005 from $46,000/MW in 2004 as a result of a decrease in generating capacity with the removal from service of the Lakeview generating station.

Depreciation and Amortization

Depreciation and amortization expense for the year ended December 31, 2005 was $276 million compared to $302 million in 2004. The decrease in expense was primarily due to the extension of the remaining service life of the Nanticoke generating station for purposes of calculating depreciation.

In June 2005, the Province provided further detail on its coal replacement plan. Specific to the Nanticoke generating station, the Province indicated its expectation that the units will be closed through 2008 with the last unit to close in early 2009. As a result, OPG has extended, for purposes of calculating depreciation, the remaining service life of the Nanticoke generating station by one year, from 2007 to 2008. This reduces depreciation expense by approximately $40 million annually over the period to 2007.

Impairment of Long-Lived Assets – Lennox Generating Station

The Lennox generating station has available generating capacity in excess of 2,000 MW. It is available to provide operating reserve, and has dual fuel capability with natural gas and oil. The Lennox generating station has annual fixed operating costs of about $60 million. Since the formation of OPG in 1999, revenue earned from electricity generated at the Lennox station was generally not sufficient to cover the fixed operating costs and annual depreciation charge related to the station. However, up until 2004, OPG expected that in the future, demand for new electricity supply requirements in Ontario would require the development of a capacity market or higher market prices sufficient for new entrants to cover their costs and provide a return on investment. As a result, revenues associated with the Lennox generating station were expected to be sufficient to cover all costs, including a recovery of the carrying value.

In 2004, the Government issued a "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" under which new generators would be allowed to recover fixed costs and an agreed upon rate of return on investment through contractual arrangements. By recovering these costs through contractual arrangements with the OPA, new entrants would need to recover only fuel and other variable operating costs from the wholesale market. These contracts are expected to result in lower than anticipated future revenue from the wholesale electricity market.

As a relatively high cost plant, the Lennox generating station likely will not be able to recover its fixed operating costs and the carrying value from the wholesale market in the future. Given these factors, and the precedent established under the Request for Information/Request for Proposal for 2,500 MW, OPG had initiated discussions with the Province, with the intention of entering into a contractual arrangement for the recovery of the annual fixed operating costs of about $60 million and the carrying value of the Lennox generating station over its remaining estimated useful life of $17 million per year.

OPG followed up on the discussions with the Province concerning the Lennox generating station situation by engaging in discussions with the IESO during the first quarter of 2005. OPG expected that it would be able to negotiate an arrangement that would provide for the recovery of all costs. Subsequently, OPG was advised by the Province that while it would continue to support OPG's negotiations with the IESO regarding the recovery of fixed operating costs, it would not support an arrangement that would allow for the recovery of costs related to the carrying value of the Lennox generating station. As a result of the change in circumstance, OPG recorded an impairment loss of $202 million during the first quarter of 2005, which was the amount of the carrying value of the generating station before the impairment loss. OPG has since negotiated a contract with the IESO pursuant to the market rules to recover its operating costs for a one-year period ending September 30, 2006. The contract with the IESO has been submitted to the OEB for approval.

Other

(millions of dollars)	**2005**	2004
Revenue	**86**	105
Operations, maintenance and administration	**57**	62
Depreciation and amortization	**35**	32
Property and capital taxes	**4**	14
Restructuring	**6**	4
Other income	**–**	(8)
(Loss) income before interest and income taxes and extraordinary item	**(16)**	1

Revenue

Other revenue was $86 million during the year ended December 31, 2005 compared to $105 million in 2004. The decrease of $19 million in 2005 compared to 2004 was primarily related to a decrease in trading revenue, partly offset by an increase in revenue from OPG's joint venture share in Brighton Beach. Brighton Beach went into service in July 2004.

Trading revenue for the year ended December 31, 2005 was $17 million compared to trading revenue of $47 million in 2004. The decrease of $30 million during 2005 compared to 2004 was primarily due to mark-to-market losses on long-term contracts outside of Ontario, which were arranged by OPG's predecessor company, Ontario Hydro. During 2005, a decrease in realized trading margin also contributed to lower trading revenue compared to 2004.

Interconnected purchases and sales (including those to be physically settled) and mark-to-market gains and losses (realized and unrealized) on energy trading contracts are disclosed on a net basis in the consolidated statements of income. If disclosed on a gross basis, revenue and power purchases for the year ended December 31, 2005 would have increased by $228 million (2004 – $170 million), with no impact on net income.

The carrying amounts and notional quantities of derivative instruments not designed for hedging purposes are disclosed in Note 12 in the audited consolidated financial statements.

Net Interest Expense

Net interest expense for 2005 was $197 million compared to $189 million in 2004. The increase in net interest expense of $8 million during 2005 was mainly due to higher long-term debt in 2005, partially offset by an increase in interest income as a result of higher cash on hand and short-term investments in 2005, and an increase in interest capitalized.

Income Taxes

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in the regulated rates charged to future customers. For all other operations, the liability method of tax accounting is followed. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Income tax expense for the year ended December 31, 2005 was $118 million compared to an $80 million income tax recovery in 2004. During 2005, OPG recorded an income tax charge of $50 million to provide for a change in income tax liabilities related to certain income tax positions that the Company has taken in prior years. During 2005, the income tax expense was $157 million lower than what would otherwise have been recorded, due to the application of the taxes payable method for the regulated segments.

As a result of the adoption of the taxes payable method for the rate regulated segments on April 1, 2005, OPG eliminated the net future income tax asset balance of $74 million relating to the rate regulated segments and recognized the amount as a one-time extraordinary loss in determining net income.

Prior to 2004, OPG had established a valuation allowance of $93 million to recognize that it was more likely than not that this amount of future income taxes recoverable would not be realized in light of consecutive taxable losses in preceding years. In 2004, the valuation allowance was reduced by $93 million to nil as a consequence of the introduction of rate regulation. With the intended elimination of the future income tax assets and liabilities of the regulated business upon inception of rate regulation on April 1, 2005, it was expected that there would be a significant future income tax liability position remaining in the unregulated business. This expected future income tax liability position enabled OPG to recognize, in 2004, the $93 million in future income tax assets. This resulted in a reduction in the 2004 income tax provision, which did not recur in 2005.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999, to reflect reassessments and appeal settlements of certain OPG properties since that date. Updates to the regulation may not occur for up to two years. OPG has not recorded any amounts relating to this anticipated regulation change.

Liquidity and Capital Resources

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing and credit facilities provided by OPG's Shareholder. These resources are required for continued investment in plant and technologies, and to meet other significant funding obligations including contributions to the pension fund and the Nuclear Funds, and to service and repay long-term debt and revenue limit rebate obligations.

Years ended December 31 (millions of dollars)	**2005**	2004	Explanation
Cash and cash equivalents, beginning of year	**2**	286	
Cash flow provided by (used in):			
Operating activities	**1,201**	226	Increase in cash from operating activities primarily due to higher sales revenue and earnings in 2005 compared to 2004, and lower rebate payments.
Investing activities	**(760)**	(543)	Increase in cash used in investing activities due to the treatment of non-capital expenses related to the Pickering A return to service project as a regulatory asset in 2005, partially offset by a decrease in investment in fixed assets.
Financing activities	**465**	33	Increase in cash from financing activities due primarily to issuance of long-term debt in 2005, partially offset by a net decrease in the issue of short-term notes.
Net increase (decrease)	**906**	(284)	
Cash and cash equivalents, end of year	**908**	2	

Operating Activities

Net cash from operating activities was $1,201 million for the year ended December 31, 2005 compared to $226 million in 2004. The increase in cash flow from operating activities in 2005 was primarily due to higher revenue and earnings in 2005 as a result of the increase in OPG's average sales prices and generation, and reduced Market Power Mitigation Agreement rebate payments in 2005. These favourable impacts on net cash from operating activities were partially offset by an increase in pension contributions in 2005 compared to 2004.

OPG made rebate payments of $851 million during 2005 under the Market Power Mitigation Agreement compared to payments of $1,124 million during 2004. The Market Power Mitigation Agreement was terminated as of March 31, 2005. Under this Agreement, OPG paid rebates totalling $4 billion between May 1, 2002, when the Ontario market opened to competition, and December 31, 2005, resulting in a significant unfavourable impact on OPG's liquidity.

Under the revenue limit rebate, which was introduced effective April 1, 2005, OPG is required to rebate $739 million in 2006, representing the generation output subject to the revenue limit of 4.7¢/kWh for the period between April 1, 2005 and December 31, 2005. Additional revenue limit rebates incurred between January 1, 2006 and April 30, 2006 will be paid in 2006, along with additional rebate payments as a result of the extension of the revenue limit beyond April 30, 2006.

OPG made contributions of $254 million to the pension plan in 2005 compared to $154 million in 2004. Pension contributions were increased in 2005 to reflect funding requirements based on a January 1, 2005 actuarial valuation of the pension plan.

As required under ONFA, OPG made total contributions of $454 million to the nuclear fixed asset removal and nuclear waste management funds in 2005 and 2004.

Investing Activities

OPG is in a capital-intensive business that requires continued investment in plant and technologies to improve generating asset performance through production efficiencies and increased reliability, increase the generating capacity of existing stations, add new generating capacity, and maintain and improve the safety and environmental performance of its assets. Capital expenditures during the year ended December 31, 2005 were $498 million compared with $561 million in 2004. The decrease in capital expenditures was due to a reduction in Pickering A return to service and environmental qualification capital expenditures in 2005 and the completion of construction activity at Brighton Beach in 2004, partially offset by expenditures on the Niagara tunnel. OPG's anticipated capital expenditures for 2006 are expected to increase to approximately $850 million, primarily as a result of the Niagara tunnel project and expenditures related to the Lac Seul and Thunder Bay generating station projects.

Financing Activities

OPG renewed its $1 billion revolving committed bank credit facility as of May 2005. The renewed facility is divided into two tranches – a $500 million 364-day term tranche maturing in May 2006 and a $500 million three-year term tranche maturing in May 2008. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2005, OPG had no borrowing outstanding under its commercial paper program compared to $26 million outstanding as at December 31, 2004. OPG has not borrowed under its commercial paper program since April 2005. As at December 31, 2005, OPG had no other outstanding borrowing under its bank credit facility.

OPG maintains $26 million (2004 – $26 million) in short-term uncommitted bank operating credit facilities as well as $215 million (2004 – $200 million) of other short-term uncommitted credit facilities, to support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and is required to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as required under the Market Rules (Ontario Energy Board's Retail Settlement Code). At December 31, 2005, there was a total of $157 million (2004 – $155 million) of Letters of Credit issued, $138 million relating to supplementary pension plans and $19 million relating to collateral requirements to the LDCs.

In March 2005, the Company reached an agreement with the OEFC to obtain additional long-term financing for up to $600 million. The financing was required to meet a projected operating cash shortfall. In April 2005, $400 million was advanced under this facility for a seven-year term. In accordance with the OEFC Agreement, the remaining $200 million of additional financing is available to be drawn up to March 31, 2006.

In March 2005, OPG issued a note of $95 million to the OEFC. This financing was used for payment of OPG's interest obligation to the OEFC.

In September 2005, OPG reached an agreement with the OEFC to finance the Niagara tunnel construction project. The funding, of up to $1 billion, will be advanced in the form of 10-year notes, on commercial terms and conditions, over the duration of the project to meet the project's obligations. Advances under this facility are expected to commence in the second quarter of 2006.

In October 2005, OPG reached a similar agreement with the OEFC to finance the Thunder Bay Gas Conversion project. There is up to $95 million available to OPG under this credit facility that will be drawn as needed over the projected two-year construction period. OPG is expected to make its first draw under this facility in the first quarter of 2006.

As at December 31, 2005, OPG's long-term debt outstanding with the OEFC was $3.7 billion. Although the new financing added in 2005 has extended the maturity profile, $3 billion of long-term debt must be repaid or refinanced within the next five years.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2005 are as follows:

(millions of dollars)	2006	2007	2008	2009	2010	Thereafter	**Total**
Contractual obligations:							
Fuel supply agreements	693	425	197	68	15	15	**1,413**
Contributions under ONFA	454	454	679	350	350	1,403	**3,690**
Long-term debt repayment	800	400	400	350	970	775	**3,695**
Interest on long-term debt	214	168	145	122	90	55	**794**
Unconditional purchase obligations	26	20	12	9	15	27	**109**
Long-term accounts payable	28	28	9	–	–	–	**65**
Operating lease obligations	13	13	13	13	14	–	**66**
Pension contributions[1]	254	–	–	–	–	–	**254**
Other	75	34	35	34	35	11	**224**
Significant commercial commitments:							
Niagara Tunnel	158	173	172	116	1	–	**620**
Total	2,715	1,715	1,662	1,062	1,490	2,286	**10,930**

1. The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuation as at January 1, 2005. The contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, and the timing of funding valuations. Funding requirements after 2006 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

Credit Ratings

Maintaining an investment grade credit rating is essential for corporate liquidity, and cost effective capital market access. At December 2005, OPG has a long-term credit rating of BBB+ by Standard & Poor's ("S&P") and A (low) by Dominion Bond Rating Service ("DBRS"). In May 2005, following a review of the new interim regulatory framework in which OPG will operate, DBRS changed the trend on OPG's unsecured debt from negative to stable and confirmed the rating on OPG's commercial paper at R-1 (low). In September 2005, S&P revised OPG's rating outlook from developing to positive, and confirmed OPG's BBB+ long-term corporate credit rating and short-term A-2 commercial paper rating.

Critical Accounting Policies and Estimates

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the consolidated financial statements as at and for the year ended December 31, 2005. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates and the impact of changes in certain conditions or assumptions, are highlighted below.

Rate Regulated Accounting

A regulation made pursuant to the *Electricity Restructuring Act, 2004* prescribes that OPG's nuclear and baseload hydroelectric facilities receive regulated prices for their output. Under this regulation, OPG is required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that are associated with the return to service of units at the Pickering A nuclear generating station. As at December 31, 2005, the deferral account balance was $261 million, consisting of non-capital costs of $228 million related to Unit 1, $19 million related to Units 2 and 3, $11 million of general return to service costs and interest of $7 million accreted at the average cost of debt of six per cent. OPG commenced the amortization of the deferral account associated with Unit 1 of the Pickering A nuclear generating station when the unit was returned to service in November 2005. The amortization of $4 million was charged to OM&A expense. Upon OPG becoming subject to regulated prices established by the OEB in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account through rates charged to future customers on a straight-line basis, over a period not to exceed 15 years.

In addition, under the regulation, OPG is required to establish an account to record certain variances from forecast, incurred on or after April 1, 2005, associated with a number of predefined circumstances. Under the terms of the regulation, the OEB is directed to ensure that OPG recovers those amounts, which have been prudently incurred and accurately recorded, through rates charged to future customers over a period not to exceed three years. Conversely, OPG will return to customers, where appropriate, certain other variance amounts recorded in this account. As at December 31, 2005, OPG had recorded a regulatory liability of $4 million in a variance account reflecting water conditions that were favourable to those forecasted. Other regulatory liability consists of a portion of non-regulated revenue earned by OPG's regulated assets, which will result in a reduction of future regulated rates to be established by the OEB. OPG also had recorded a regulatory asset of $5 million related to revenues for ancillary services that were below the forecast used to establish regulated rates. The measurement of regulatory assets and liabilities are subject to certain estimates and assumptions including assumptions made in the interpretation of the regulation.

With the commencement of rate regulation for OPG's baseload hydroelectric and nuclear facilities on April 1, 2005, OPG recorded an extraordinary loss of $74 million resulting from the elimination of the net future income tax asset.

Income Taxes

OPG is exempt from tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by regulations made under the *Electricity Act, 1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act, 1998,* and tax related regulations are relatively new and it was therefore necessary for OPG to take certain filing positions in calculating the amount of the income tax provision. These filing positions may be challenged on audit and possibly disallowed, resulting in a potential significant increase in OPG's tax provision upon reassessment. Although management believes that it has adequately provided for income taxes based on all information currently available, there is uncertainty given how recently the legislation was introduced.

OPG uses the liability method of accounting for income taxes for the unregulated segment of the business and provides future income taxes for income tax temporary differences. The process involves an estimate of OPG's actual current tax liability and an assessment of the Company's future income taxes as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value on the consolidated balance sheet. In addition, OPG has to assess whether the future tax assets can be realized and to the extent that recovery is not considered likely, a valuation allowance must be established. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business in accordance with paragraphs 102 to 104 inclusive of the Canadian Institute of Chartered Accountants ("CICA") handbook, Section 3465 – Income Taxes. Accordingly, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that these income taxes are expected to be recovered in the regulated rates charged to future customers.

Future tax assets of $269 million have been recorded on the consolidated balance sheet at December 31, 2005. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards. Because of the adoption of rate regulated accounting, OPG did not record future tax assets of $3,297 million, which it would have recorded under the liability method, resulting primarily from temporary differences related to the nuclear fixed asset removal and nuclear waste management provisions.

Future tax liabilities of $492 million have been recorded on the consolidated balance sheet at December 31, 2005. Because of the adoption of rate regulated accounting, OPG did not record future tax liabilities of $3,380 million, which it would have recorded under the liability method, resulting primarily from temporary differences related to the nuclear fixed asset removal and nuclear waste management fund.

Business Segments

Prior to April 1, 2005, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Other, included revenue and certain expenses that were not allocated to its business segments. With the introduction of rate regulation, OPG changed the definition of its reportable business segments in order to remain compliant with the CICA handbook, Section 1701 – Segment Disclosure. OPG reports its results on the basis of these new segments beginning April 1, 2005 and has reclassified prior period amounts accordingly.

Impairment of Generating Stations and Other Fixed Assets

OPG's business is capital intensive and requires significant investment in property, plant and equipment ("fixed assets"). At December 31, 2005, the net book value of OPG's fixed assets was $11,412 million.

Property, plant and equipment are tested for recoverability whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Recoverability of property, plant and equipment is determined by comparing the carrying amount of an asset to the undiscounted future net cash flows expected to be generated from the asset over its estimated useful life. In cases where the undiscounted expected future cash flows are less than the carrying amounts, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value, or discounted cash flows.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new and laid-up generating stations, inflation, fuel prices, capital expenditures and station lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

Pension and Other Post Employment Benefits

OPG's accounting for pension and other post employment benefits are dependent on management's accounting policies and assumptions used in calculating such amounts.

Accounting Policy

In accordance with Canadian generally accepted accounting principles, actual results that differ from the assumptions used, as well as adjustments resulting from changes in assumptions, are accumulated and amortized over future periods and therefore generally affect recognized expense and the recorded obligation in future periods.

Under OPG's policy on accounting for pension and OPEB, certain actuarial gains and losses have not been charged to expense and are therefore not reflected in OPG's pension and OPEB obligations as a result of the following:

- Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.
- For pension and OPEB, the excess of the net cumulative unamortized gain or loss, over 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life.

In addition, past service costs arising from pension and OPEB plan amendments are amortized over future periods and therefore affect recognized expense and the recorded obligation in future periods.

At December 31, 2005, the unamortized net actuarial loss and unamortized past service costs for the pension plan and other post employment benefits amounted to $2,760 million (2004 – $1,604 million). Details of the unamortized net actuarial loss and total unamortized past service costs at December 31, 2005 and 2004 are as follows:

	Registered Pension Plan		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2005**	2004	**2005**	2004	**2005**	2004
Net actuarial loss (gain) not yet subject to amortization due to use of market-related values	**(48)**	476	**–**	–	**–**	–
Net actuarial loss not subject to amortization due to use of corridor	**910**	536	**14**	14	**207**	150
Net actuarial loss subject to amortization	**875**	–	**4**	14	**678**	272
Unamortized net actuarial loss	**1,737**	1,012	**18**	28	**885**	422
Unamortized past service costs	**100**	119	**4**	5	**16**	18

Accounting Assumptions

Assumptions used in determining projected benefit obligations and the costs for the Company's employee benefit plans are evaluated periodically by management in consultation with an independent actuary. Critical assumptions such as the discount rate used to measure the Company's benefit obligations, the expected long-term rate of return on plan assets and health care cost projections are evaluated and updated annually. The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields.

A change in these assumptions, holding all other assumptions constant, would increase (decrease) 2005 costs, excluding amortization components, as follows:

(millions of dollars)	Registered Pension Plan	Supplementary Pension Plans	Other Post Employment Benefits
Expected long-term rate of return			
0.25% increase	(19)	na	na
0.25% decrease	19	na	na
Discount rate			
0.25% increase	(10)	–	(2)
0.25% decrease	11	–	2
Inflation			
0.25% increase	31	1	na
0.25% decrease	(29)	(1)	na
Salary increases			
0.25% increase	7	2	–
0.25% decrease	(7)	(1)	–
Health care cost trend rate			
1% increase	na	na	26
1% decrease	na	na	(20)

na – change in assumption not applicable

Asset Retirement Obligations

OPG's asset retirement obligations are comprised of liabilities for nuclear fixed asset removal and nuclear waste management costs and non-nuclear fixed asset removal costs related to the decommissioning of fossil-fuelled generating stations. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. The estimates of the nuclear liabilities are reviewed on an annual basis as part of the ongoing, overall nuclear waste management program. Changes in the nuclear liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with a corresponding change in the related asset retirement cost capitalized as part of the carrying amount of the long-lived asset.

The estimates of nuclear fixed asset removal and nuclear waste management costs require significant assumptions in the calculations since the programs run for many years. Significant assumptions underlying operational and technical factors are used in the calculation of the accrued liabilities and are subject to periodic review. Changes to these assumptions, including changes in the timing of programs, technology employed, inflation rate, and discount rate, could result in significant changes in the value of the accrued liabilities.

The current estimate of costs to complete the nuclear fixed asset removal and nuclear waste management is in accordance with the current approved reference plan. OPG is currently performing a detailed review, which will result in an updated reference plan. It is expected that this updated reference plan will be completed and approved during 2006.

With the return to service of Unit 1 at the Pickering A nuclear generating station and the decision in 2005 not to restart Units 2 and 3, OPG is reviewing the impact that these events will have on the assumptions, changes in timing to programs and the estimated costs underlying the accrued nuclear fixed asset removal and nuclear waste management liability. Any resulting changes to the estimated accrual will be reflected in the planned update to the reference plan in 2006.

Depreciation

Property, plant and equipment for OPG's generating stations are depreciated based on their estimated service lives on a straight-line basis. The service lives of the generating stations are estimated based on expected consumption, government legislation and management intent.

In June 2005, the Province provided further details on its coal replacement plan. Hence, effective in July 2005, OPG extended, for purposes of calculating depreciation, the remaining service life of the Nanticoke generating station for one year to December 2008. This change in estimate was accounted for on a prospective basis and reduced the depreciation expense by $20 million in 2005.

OPG has also extended, for purposes of calculating depreciation, the remaining service life of the Pickering A nuclear generating station Unit 4 from 2017 to the year 2021, consistent with the remaining service life of Unit 1. This change reflects management's assessment of the remaining service life, taking into account the recent refurbishment of this unit. This change was effective in November 2005 and reduces depreciation expense by approximately $16 million annually over the period to 2017, excluding the impact of future asset additions planned at the station.

OPG will continue to review the estimated useful lives of its generating stations including the Pickering B Units. Any changes resulting from the review will be reflected in 2006.

Risk Management

OPG's portfolio of generation assets and its electricity trading and marketing operations are subject to inherent risks, including financial, operational, and strategic risks. To manage these risks, OPG's Board of Directors and management have implemented an integrated enterprise-wide risk management framework for the governance, identification, measurement, monitoring and reporting of risk across all of OPG and its business operations. Implementation and coordination of corporate-wide risk management activities are undertaken through a centralized risk management group, separate and independent from operational management. Risk information from the business units is independently assessed and aggregated by the risk management group, and is reported by the Chief Risk Officer to the Audit and Risk Committee of the Board of Directors on a routine basis. Risk based processes are incorporated into strategic and financial planning to ensure the Company's sustainability and achievement of its stated objectives.

While OPG believes it is pursuing appropriate risk management strategies, there can be no assurance that one or more of the risks outlined or other risk factors will not have a material adverse impact on OPG. In particular, the *Electricity Restructuring Act, 2004* and related regulations, the imposition of a revenue limit on the non-regulated assets excluding the Lennox generating station and volumes related to existing contracts, and changes in the future mandate of OPG in the Ontario electricity marketplace could have a material impact on OPG.

Risk Classification

For purposes of tracking and communicating risk information, the Company uses the following three major risk categories including:

- Financial Risk: the risk of financial loss caused by external market factors, including market prices and volatilities, credit, foreign exchange, interest rate, liquidity and other factors,
- Operational Risk: the risk of direct or indirect loss resulting from external events or from inadequate or failed internal processes, people, equipment and systems. These include changes in generation reliability, fuel supply and availability, security, business process risks, business interruption, human resources risks and information technology risks, and
- Strategic Risk: the risk that adverse events or conditions in OPG's regulatory, economic, political and social environment will prevent OPG from achieving its objectives. These include risks from adverse regulatory changes or onerous existing regulations; risks from unexpected economic conditions; the risk of financial loss or damaged reputation resulting from unexpected political actions; and succession planning risk.

Risk Management Tools

In addition to qualitative indicators provided through risk-based internal audits, reviews and self-assessments, OPG uses quantitative tools and metrics for monitoring and managing risks. OPG continuously assesses the appropriateness and reliability of risk management tools and metrics in light of the changing risk environment. Some of the tools and metrics that OPG currently uses to measure and report on risk are:

- Business Unit Risk Self-assessments (BURSA©) are conducted across the Company annually, and updated quarterly. Using standard criteria for assessing the probability and consequence of risk events, OPG business units assess the risks in their processes, operations and projects. The output from the BURSA process helps the business units develop risk mitigation plans to avoid, transfer, reduce or accept the risk and make risk-based capital allocation decisions,
- Value-at-Risk (VaR) analysis is used to measure and manage market risks in OPG's electricity trading portfolio. The VaR approach is used to derive a quantitative measure specifically for market risks under normal market conditions. For a given portfolio, VaR measures the possible future loss (in terms of market value) which, under normal market conditions, will not be exceeded within a defined probability and time period,
- Stress tests help to determine the effects of potentially extreme market developments on the market values of electricity trading and marketing positions. Stress testing is used to determine the amount of economic capital OPG needs to allocate to cover market risk exposure under extreme market conditions, and
- Economic capital is a measure of the amount of equity capital needed at any given date to absorb unexpected losses arising from exposures on that date. Currently, OPG calculates credit economic capital in relation to Energy Markets activities.

Financial Risk

Commodity Price Risk

Commodity price risk is the risk that changes in the market price of electricity or of the fuels used to produce electricity will adversely impact OPG's earnings and cash flow from operations. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios to the extent that trading liquidity in the relevant commodities markets provides the opportunity to do so in an economically justified manner. To manage the input risk, OPG has a fuel hedging program. In addition to fixed price contracts for fossil and nuclear fuels, OPG periodically employs derivative instruments to hedge its fuel price risk.

Through a regulation passed pursuant to the *Electricity Restructuring Act, 2004,* OPG receives regulated prices for its baseload hydroelectric and nuclear facilities (approximately 60 per cent of OPG generation) from April 1, 2005. These prices are expected to remain in effect until at least March 31, 2008, or until such time that the OEB establishes new regulated prices. Eighty-five per cent of the remaining unregulated OPG electricity generation, excluding generation from the Lennox generating station and volumes relating to existing contracts, is subject to a revenue limit of 4.7¢/kWh, in place from April 1, 2005 to April 30, 2006. The Government recently announced the extension of this revenue limit for an additional three years.

The percentages of OPG's expected generation, emission requirements and fuel requirements hedged are shown below:

	2006	2007	2008
Estimated generation output hedged[1]	92%	92%	93%
Estimated fuel requirements hedged[2]	97%	89%	77%
Estimated nitric oxide (NO) emission requirement hedged[3]	100%	77%	68%
Estimated sulphur dioxide (SO_2) emission requirement hedged[3]	100%	100%	100%

1. Represents the portion of megawatt hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under the transition rate option contracts, regulated price for baseload hydroelectric and nuclear generation, and revenue limit for non-prescribed assets.
2. Represents the approximate portion of megawatt hours of expected generation production (and fossil year-end inventory target) from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangements or obligations in order to secure either the expected availability and/or price of fuel and/or fuel related services. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios. Since production from hydroelectric facilities is primarily influenced by expected weather and weather patterns, fuel hedge ratios for hydroelectric facilities are assumed to be 100 per cent.
3. Represents the approximate portion of megawatt hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.

Open trading positions are subject to measurement against Value at Risk ("VaR") limits. VaR utilization ranged between \$0.7 million and \$3.0 million during the year ended December 31, 2005, compared to \$0.4 million and \$2.2 million during the year ended December 31, 2004. VaR utilization is within the risk tolerance of the Company, under approved VaR limits.

Trading liquidity continues to be constrained in Ontario and interconnected markets due to broader energy market fundamentals. In addition, the revenue limit reduces customer exposure to electricity spot market prices and further limits trading liquidity.

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. OPG derives revenue from several other sources including the sale of energy products and financial risk management products to third parties. However, the majority of OPG revenues are derived from sales through the IESO-administered spot market.

Credit exposure to the IESO fluctuates based on spot prices and the volume of rate regulated and unregulated generation, and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at \$1,146 million during the year ended December 31, 2005 and at \$901 million during the year ended December 31, 2004.

OPG's management believes that the IESO is an acceptable credit risk due to its primary role in the Ontario market. The IESO manages its own credit risk and its ability to pay generators by mandating that all registered IESO spot market participants meet specific IESO standards for creditworthiness and collateralization. Additionally, in the event of an IESO participant default, each market participant shares the exposure pro rata. Given OPG's position in the marketplace, the Company would bear approximately 35 per cent of the exposure, residual of collateral and recovery.

OPG also monitors and reports its credit exposure with counterparties. OPG's management believes these are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at December 31, 2005:

			Potential Exposure for Largest Counterparties	
Credit Rating[1]	Number of Counterparties[2]	Potential Exposure[3]	Number of Counterparties	Counterparty Exposure
		(millions of dollars)		(millions of dollars)
AAA to AA-	38	3	–	–
A+ to A-	44	37	1	15
BBB+ to BBB-	85	32	1	10
BB+ to BB-	27	145	7	135
Below BB-	32	62	1	59
Subtotal	226	279	10	219
IESO	1	661	1	661
Total	227	940	11	880

1. Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.
2. OPG Counterparties are defined by each Master Agreement.
3. Potential exposure is OPG's assessment of the maximum exposure over the life of each transaction at 95 per cent confidence.

For all counterparties, OPG's contracts allow for active collateral management to mitigate credit exposures. The contracts provide for a counterparty to post performance guarantees in excess of the established threshold. OPG may employ such guarantees as a result of market price changes or upon the occurrence of credit-related events. The threshold amount represents credit limits established in accordance with the corporate credit policy. Inability to post collateral is sufficient cause to terminate a contract and liquidate all positions.

Liquidity Risk

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects and maintenance at generating stations and potential expenditures necessary to comply with environmental or other regulatory requirements. In addition, the Company has other significant disbursement requirements including rebate payments associated with the revenue limit, annual funding obligations under ONFA, pension funding and continuing debt maturities with the OEFC. A discussion of corporate liquidity is included in the Liquidity and Capital Resources section.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange exposure is attributable to two primary factors: U.S. dollar ("USD") denominated transactions such as the purchase of fossil fuels; and the influence of USD denominated commodity prices on Ontario electricity spot market prices, impacting OPG's revenues. The magnitude and direction of the exposure to the USD from OPG's operations is impacted by generation reliability and the price volatility of USD denominated commodities. OPG currently manages its exposure using forwards and other derivative products to periodically hedge portions of its anticipated USD exposures according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's existing debt is fixed on a long-term basis. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by selectively hedging in accordance with corporate risk management policies.

Operational Risk

Generation Risk

OPG is exposed to the financial impacts of uncertain output from its generating units. The amount of electricity generated by OPG is affected by fuel supply, equipment malfunction, maintenance requirements, and regulatory and environmental constraints. To mitigate earnings volatility due to generation risk, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories, and follows industry practices for maintenance and outage scheduling. In addition, OPG ensures regulatory requirements are met, particularly with respect to licensing of its nuclear facilities, and manages environmental constraints utilizing programs such as emission reduction credits.

OPG is exposed to considerable technology risk around the aging of the nuclear fleet. Technology risks that could lead to significant impacts on the production capability or operating life of these assets are not fully predictable and OPG attempts to identify and mitigate these risks through ongoing management review and assessments, internal audits and from experience of nuclear units around the world. OPG has undertaken an ongoing life cycle management program to assess the condition of major components of the nuclear units, including steam generators, fuel channels and feeder pipes, and address the active degradation mechanisms associated with these major components. Current predictions for unit end of life are based on the end of life predictions for the fuel channels.

Thinning of the carbon steel feeder pipes used to transport the hot pressurized water in the reactor to the steam generators is an industry-wide issue. Thinning of feeder pipes occurs to varying degrees at all of OPG's reactors. While this condition affects all of OPG's nuclear generating stations, it is most significant at the Darlington nuclear generating station. Mitigation options are under development by OPG which may extend feeder pipe life, reduce the thinning rate, and improve the capability to replace feeders, where required. Recent wall thickness measurements of removed feeders and field inspections at Pickering A Units 1 and 4 have indicated that the location of the thinning is different than at Darlington, and the degree of thinning is greater than originally expected. Future inspections will be required to confirm the thinning rate at Pickering A, and to determine the need for future feeder pipe replacements. Pickering B feeder pipes have been found to be less affected by thinning than those at the Darlington and Pickering A generating stations.

Cracking of feeder pipes has been experienced at two CANDU plants located outside Ontario. At those plants, the affected sections of pipe were replaced and the units were returned to service. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities, but is carrying out inspections during regularly planned outages. The scale of these inspections has been increased to address the concern that the risk of cracking may be increasing in OPG's units. OPG is also participating in research and development with other CANDU operators to better understand the degradation mechanisms.

The Pickering A reactors are unique among the CANDU fleet in that the reactor is contained within an air-filled concrete enclosure called the "calandria vault". The environment is potentially corrosive to carbon steel components contained within the calandria vault structure, particularly when the atmosphere is humid. Significant degradation of the carbon steel components occurred early in life. Maintenance was carried out during the 1980s and early 1990s to mitigate the degradation and repair some of the degraded components. Equipment was added to maintain a dry vault atmosphere and thereby significantly reduce the risk of corrosion. There is limited information to determine the extent to which mitigation efforts have been successful. Further inspections are being planned.

In 2004, inspections of Pickering A Unit 2 uncovered a single crack originating in the outer diameter of the steam generator tubing. This was the first crack observed in any of the Pickering A and B steam generator tubes and resulted in an increase in the scope of inspection for all Pickering A and B steam generators. Inspection of Pickering A Unit 4 in 2005 confirmed the presence of a single crack. Inspections of the other Pickering A and B units (including recent inspection of Pickering A Unit 1 in 2004 and Pickering B Units 5 and 6 in 2005) have not uncovered any further cracks. Operating units observed to have cracked tubes would likely require a shortened operating interval in the range of one year before inspection. Tubes which cannot be demonstrated to be fit for service can be removed from service; this may impact outage duration and costs.

Environmental Risk

OPG incurs substantial capital and operating costs to comply with environmental laws. The regulatory requirements relate to discharges to the environment; construction of or modifications to our facilities; the handling, use, storage, transportation, disposal and clean-up of hazardous substances and waste; and the decommissioning of generation facilities at the end of their useful lives.

OPG's Sustainable Development Policy commits OPG to meet all applicable legislative requirements and voluntary environmental commitments, integrate environmental factors into business planning and decision-making, and apply the precautionary principle in assessing risks to human health and the environment. This policy also commits OPG to maintain comprehensive EMSs at our generating facilities consistent with the ISO 14001 standard.

OPG monitors emissions into the air and water and regularly reports the results to various regulators, including the Ministry of Environment, Environment Canada and the Canadian Nuclear Safety Commission. The public also receives ongoing communications regarding OPG's environmental performance through community-based advisory groups, annual environmental reports, community newsletters, open houses and OPG's web site. OPG has developed and implemented internal monitoring, assessment and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, radioactive emissions and radioactive wastes. OPG also continues to address historical land contamination through its voluntary land assessment and remediation program.

OPG's SO_2 and NO_x emissions are managed through the installation of specialized equipment such as scrubbers to reduce SO_2 emissions, low NO_x burners and selective catalytic reduction equipment to reduce NO_x emissions, and through the purchase of low sulphur fuel. OPG also utilizes a regulatory approved emissions trading program to manage emission levels within regulatory limits. The Province's coal replacement policy directs OPG to phase out the use of coal-fired generation during the period 2007 to 2009. In the interim, OPG will operate its coal-fired facilities in accordance with all regulatory requirements and will implement continuous improvement measures that are consistent with the remaining in-service requirements for these facilities.

OPG's emissions of greenhouse gases ("GHG") have been managed on a voluntary basis, primarily through improvements in energy efficiency and the purchase of GHG emission reduction credits. The Kyoto Protocol, to which Canada is a signatory, came into force on February 16, 2005. To meet Canada's international obligations under the Protocol, the federal government's Climate Change Plan includes the provision for regulations to be applied to Large Final Emitters ("LFE") of GHG, including OPG. The LFE regulations, if finalized as currently proposed, would require OPG to reduce the CO_2 intensity at each fossil facility in operation beyond 2008 by approximately 13.5 per cent relative to 2000 levels. Under the implementation timeline for the Government's coal replacement policy, Nanticoke generating station would be the only coal-fired facility running beyond 2008. As a result, the cost of achieving the proposed limit at Nanticoke through the use of emission reduction credits could be $60 million annually, assuming access to the $15/tonne carbon dioxide (CO_2) price assurance mechanism.

Changes to environmental laws or delays in implementing the current timetable of the Government's coal replacement policy could create compliance risks that may be addressed by the installation of additional equipment or control technologies, the purchase of additional emission reduction credits, or by constraining production from the fossil-fuelled fleet. In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges. Further, some of OPG's activities have the potential to cause contamination to land or water that may require remediation. The potential liability associated with any of these events could have a material adverse effect on the business.

Regulatory Risk

Through a regulation passed pursuant to the *Electricity Restructuring Act, 2004,* OPG receives regulated prices for its baseload hydroelectric and nuclear facilities from April 1, 2005. These prices are expected to remain in effect until at least March 31, 2008. Some time after March 31, 2008, the OEB is expected to establish new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend these initial prices. Any such changes pose a risk that the return on equity factored into the existing prices could be reduced. Equally, to the extent that costs incremental to those included in the price determination process occur and no such amendments are made, these costs may be borne by OPG and not recovered through rates charged to future customers. These costs may be necessary to maintain the reliability and safety of OPG's regulated generating assets.

The regulation also directed OPG to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with certain unforeseen circumstances, and to establish a deferral account for Pickering A return to service non-capital costs incurred on or after January 1, 2005. The accuracy and prudency of any variance account balances that OPG records as a regulatory asset or liability must be demonstrated by OPG to the OEB once it establishes new regulated prices expected after March 31, 2008. Regulatory risk arises given the possibility of the OEB not approving such costs. In the event that some of these costs are disallowed by the OEB at a future date, the amounts disallowed would be reflected in results of operations in the period that the OEB decision occurs.

Strategic Risk

OPG's operations are subject to government regulation and direction that may change. Matters that are subject to regulation include: structure of the electricity market, nuclear operations including regulation pursuant to the *Nuclear Safety and Control Act* (Canada), the *Nuclear Liability Act* (Canada) and the *Emergency Plans Act* (Ontario), nuclear waste management and decommissioning, water rentals, environmental matters including air emissions, and proxy tax payments. Because legal requirements can change and are subject to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations.

Continuous Disclosure

Fourth Quarter

Net income for the three months ended December 31, 2005 was $160 million compared to net income of $34 million for the same period in 2004. Income before income taxes for the three months ended December 31, 2005 was $192 million compared to a loss of $80 million in the same period in 2004.

The details of the change in gross margin and other changes impacting fourth quarter income in 2005 compared to 2004, on a before-tax basis, are as follows:

(millions of dollars)	Three Months
Loss before income taxes for the three months ended December 31, 2004	**(80)**
Changes in gross margin	
Increase in electricity sales prices after Market Power Mitigation Agreement rebate and revenue limit rebate	230
Change in electricity generation by segment:	
Regulated – Nuclear	62
Regulated – Hydroelectric	(11)
Unregulated – Hydroelectric	11
Unregulated – Fossil-fuelled	(20)
Other changes in gross margin	(22)
	250
Decrease in Pickering A return to service OM&A expense due to deferral of non-capital costs in 2005 as a rate regulated asset	81
Increase in OM&A costs due to write-off of inventory as a result of not returning Pickering A generating station Units 2 and 3 to service	(35)
Increase in nuclear maintenance and repairs	(14)
Increase in pension and other post employment benefit costs	(21)
Increase in earnings on nuclear fixed asset removal and nuclear waste management funds	44
Other net changes	(33)
Increase in income before income taxes	**272**
Income before income taxes for the three months ended December 31, 2005	**192**

The increase in income before tax during the fourth quarter of 2005 was primarily attributable to a higher gross margin from electricity sales due to higher average sales prices compared to the same period in 2004. The increase in OPG's average sales prices in the fourth quarter of 2005 was due to higher Ontario spot market prices and the impact of the regulatory prices and related regulatory changes that took effect in 2005. Higher electricity generation in the fourth quarter of 2005 also contributed to the increase in gross margin. The increase in generation was primarily due to the return to service of Unit 1 of the Pickering A nuclear station in the fourth quarter of 2005, as well as strong performance from OPG's other nuclear generating stations.

The increase in earnings during the fourth quarter of 2005 compared to the same period last year was also due to lower OM&A expenses resulting from the deferral of non-capital costs related to the Pickering A return to service project in 2005, as required by a regulation pursuant to the *Electricity Restructuring Act, 2004,* and the completion of the Unit 1 return to service project. Amortization of the deferred OM&A amounts began during the fourth quarter of 2005 on the date of the return to service of Unit 1 in accordance with the regulation.

The improvement in earnings during the quarter was also due to higher income from the nuclear fixed asset removal and nuclear waste management funds due to a larger asset base and higher market returns compared to 2004.

The impact of these favourable changes on fourth quarter 2005 earnings was partially offset by higher OM&A expenses related to the write-off of additional inventory identified as excess as a result of the decision to not return Pickering A generating station Units 2 and 3 to service, higher nuclear maintenance and repairs expenditures, and higher pension and OPEB expenses.

After-tax earnings in the fourth quarter of 2005 were impacted by use of the taxes payable method, rather than the liability method, to account for income taxes relating to the rate regulated segments of its business upon inception of rate regulation in 2005. As a result of using this method, during the fourth quarter of 2005, OPG did not record a future tax expense for the rate regulated segments of $47 million, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method.

In 2004, OPG's income tax expense was impacted by a reduction of $93 million in a valuation allowance for future income tax assets that had previously been established. This resulted in a reduction in the 2004 income tax provision, which did not recur in 2005.

Fourth Quarter Average Sales Prices

OPG's average sales prices by business segment, net of the revenue limit rebate, for the three months ended December 31, 2005, and net of the Market Power Mitigation Agreement for the three months ended December 31, 2004, are as follows:

	Three Months Ended December 31	
(¢/kWh)	**2005**	2004
Regulated – Nuclear[1]	**4.9**	4.0
Regulated – Hydroelectric[1]	**3.9**	4.0
Unregulated – Hydroelectric[2]	**5.5**	4.2
Unregulated – Fossil-fuelled[2]	**5.6**	4.1
OPG average price	**5.0**	4.0

1. During the period from April 1, 2005, electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh. During the same period, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.
2. During the period from April 1, 2005, 85 per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit based on an average price of 4.7¢/kWh.

Cash Flow from Operations

Cash flow provided by operating activities during the fourth quarter of 2005 was $446 million compared to $152 million during the same period in 2004. The favourable change in cash flow was primarily due to higher revenue and earnings compared to 2004 and lower rebate payments in 2005. The favourable changes were partly offset by higher pension contributions during the 2005 period.

Summary of Quarterly Results

The following tables set out certain unaudited interim consolidated financial statement information for each of the 12 most recent quarters ended December 31, 2005. The information has been derived from OPG's unaudited interim consolidated financial statements that, in management's opinion, have been prepared on a basis consistent with the audited consolidated financial statements. These operating results are not necessarily indicative of results for any future period.

			2005 Quarters Ended		
(millions of dollars)	**March 31**	**June 30**	**September 30**	**December 31**	**Total Year**
Revenue after Market Power Mitigation Agreement rebate and revenue limit rebate	**1,358**	**1,373**	**1,571**	**1,496**	**5,798**
(Loss) income before extraordinary item	**(38)**	**137**	**181**	**160**	**440**
(Loss) income before extraordinary item per share	**$(0.15)**	**$0.53**	**$0.71**	**$0.62**	**$1.72**
Net (loss) income	**(38)**	**63**	**181**	**160**	**366**
Net (loss) income per share	**$(0.15)**	**$0.25**	**$0.71**	**$0.62**	**$1.43**

			2004 Quarters Ended		
(millions of dollars)	March 31	June 30	September 30	December 31	Total Year
Revenue after Market Power Mitigation Agreement rebate	1,350	1,141	1,212	1,215	4,918
Net income (loss)	64	(41)	(15)	34	42
Net income (loss) per share	$0.25	$(0.16)	$(0.06)	$0.13	$0.16

			2003 Quarters Ended		
(millions of dollars)	March 31	June 30	September 30	December 31	Total Year
Revenue after Market Power Mitigation Agreement rebate	1,480	1,246	1,224	1,228	5,178
Net income (loss)	73	8	34	(606)	(491)
Net income (loss) per share	$0.28	$0.03	$0.13	$(2.36)	$(1.92)

Balance Sheets as at December 31 (millions of dollars)	**2005**	2004	2003
Total assets	**21,623**	19,830	19,511
Total long-term liabilities	**13,640**	13,366	13,043
Cash dividends declared per share	**–**	–	0.07
Common shares outstanding (millions)	**256.3**	256.3	256.3

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. The revenue limit and the Market Power Mitigation Agreement rebates, and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations. The quarterly performances are also impacted by the factors described in the Key Generation Performance Indicator section of the MD&A.

Since April 1, 2005, revenue has increased due to the introduction of regulated prices for OPG's baseload hydroelectric and nuclear facilities and other related regulatory changes.

Off-Balance Sheet Arrangements

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. Under the securitization agreement, OPG sold an undivided co-ownership interest in certain current and future accounts receivable generated in the normal course of business. The amount of the co-ownership interest sold is removed from the consolidated balance sheet with each revolving securitization. OPG also retains an undivided co-ownership interest in the receivables sold to the trust. This retained interest is accounted for at cost on OPG's consolidated balance sheet. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. As such, the results of the trust are not consolidated. The securitization provides OPG with an opportunity to obtain an alternative source of cost effective funding. For the year ended December 31, 2005, the average all-in cost of funds was 3.1 per cent and the pre-tax charges on sales to the trust were $9 million. The initial net cash proceeds from this transaction of $300 million were used by OPG in the operation of its business. In December 2005, OPG extended the securitization agreement to August 2009. See Note 4 to the audited consolidated financial statements for more information.

Guarantees

As part of normal business, OPG and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, stand-by Letters of Credit and surety bonds.

Derivative Instruments

The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity. OPG entered into forward-start interest rate swap agreements to hedge against the effect of future interest rate movements on 10-year fixed rate borrowing requirements for the Niagara tunnel project. Financial commodity derivative instruments are entered into with large and medium volume end-use consumers and intermediaries such as U.S. utilities, brokers, aggregators, traders and other power marketers and retailers. Foreign exchange derivative instruments entered into with major financial institutions are used to hedge the exposure to anticipated U.S. dollar denominated purchases.

When a derivative instrument ceases to exist or when designation of a hedging relationship is terminated, any associated deferred gains or losses are carried forward to be recognized in income in the same period as the corresponding gains or losses associated with the hedged item. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income. The deferred loss on electricity derivative instruments and interest rate hedges was $127 million as at December 31, 2005, compared to a deferred loss of $71 million on electricity derivative instruments as at December 31, 2004. See Note 12 to the audited consolidated financial statements for more information.

All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in other revenue.

Related Party Transactions

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures.

The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

	Revenues	**Expenses**	Revenues	Expenses
(millions of dollars)	**2005**		2004	
Hydro One				
Electricity sales	**40**	**–**	40	–
Services	**–**	**12**	–	12
Settlement Transactions	**–**	**27**	–	33
Province of Ontario				
GRC water rentals and land tax	**–**	**132**	–	152
Guarantee fee	**–**	**8**	–	8
Used Fuel Fund rate of return guarantee	**–**	**–**	–	14
Decommissioning Fund excess funding	**–**	**7**	–	–
Other	**–**	**–**	–	2
OEFC				
GRC and proxy property tax	**–**	**207**	–	214
Interest income on receivable	**–**	**(75)**	–	(101)
Interest expense on long-term notes	**–**	**211**	–	191
Capital tax	**–**	**51**	–	49
Income taxes	**–**	**192**	–	(80)
Indemnity fees	**–**	**5**	–	5
IESO				
Electricity sales	**6,517**	**329**	5,465	304
Market Power Mitigation Agreement rebate	**(412)**	**–**	(1,154)	–
Revenue limit rebate	**(739)**	**–**	–	–
Ancillary services	**68**	**–**	90	–
Other	**–**	**–**	1	1
	5,474	**1,106**	4,442	804

At December 31, 2005, accounts receivable included $14 million (2004 – $14 million) due from Hydro One and $324 million (2004 – $158 million) due from the IESO. Accounts payable and accrued charges at December 31, 2005 included $2 million (2004 – $3 million) due to Hydro One.

Corporate Governance

National Instrument 58-101, Disclosure of Corporate Governance Practices, has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. Information with respect to OPG's Board of Directors is as follows:

Board of Directors and Directorships

OPG's Board of Directors is made up of individuals with substantial expertise in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board exercises its independent supervision over management as follows: with the exception of the CEO, all members of the Board are independent of the Company; meetings of the Board are held at least six times a year; a formal Charter for the Board, and for each Board Committee has been adopted; each Board Committee is chaired by an independent director; and a portion of each Board and Committee meeting is reserved for directors to meet without management present.

The following are the directors of OPG as at December 31, 2005:

Name	Principal occupation	Other directorship in any other reporting issuer (or equivalent in a foreign jurisdiction)
Hon. Jake Epp	Chairman, Ontario Power Generation Inc. Board of Directors	QHR Technologies Inc.
Donald Hintz	Retired President of Entergy Corporation	Entergy Corporation
Dr. Gary Kugler	Retired Senior Vice President, Nuclear Products and Services, Atomic Energy of Canada Limited	None
George Lewis	Chairman and Chief Executive Officer of RBC Asset Management Inc.	None
David MacMillan	Non-executive director of Killingholme Power	None
Corbin McNeill	Retired Chairman and Co-Chief Executive Officer of Exelon Corporation	Owens Illinois, Inc. Portland General Electric Company
Peggy Mulligan	Chief Financial Officer, Linamar Corporation	None
Ian Ross	Chairman, GrowthWorks Canadian Fund Ltd.	World Heart Corporation PetValu Canada Inc. GrowthWorks Canadian Fund Ltd.
Marie Rounding	Former President and Chief Executive Officer of the Canadian Gas Association	None
William Sheffield	Corporate Director	Velan Inc. Royal Group Technologies Limited
David Unruh	Corporate Director	Westcoast Energy Inc. Union Gas Limited Pacific Northern Gas Ltd. Corriente Resources Inc.
Jim Hankinson*	President and CEO, Ontario Power Generation Inc.	Maple Leaf Foods Inc. CAE Inc. Entertainment One Income Fund

* All directors listed are independent within the meaning of section 1.4 of Multilateral Instrument 52-110, Audit Committees (MI 52-110) except for Jim Hankinson who is the President and CEO of the Company.

Orientation and Continuing Education

In 2005, the Board established an orientation program for new Directors when they join the OPG Board. New directors participate in a range of orientation initiatives:

- Directors receive an overview of relevant documentation arising from a new director's election to the Board,
- Directors are provided a Director's Handbook, which provides an overview of the Board's constitution and governance practices, including Shareholder Agreements, Board and Committee Charters, Director roles and responsibilities, Board and Committee chair position descriptions, Board approved corporate policies and Code of Conduct, Director and Officer indemnities and insurance, Board and Committee evaluations, and recent Board activity,
- Directors attend a comprehensive introductory briefing session on OPG's operations and business, and
- Plant tours are provided of OPG generating facilities.

The Board supports the continuing education of directors, in both the business of OPG and their duties as directors, in a number of ways:

- Special presentations are made to the Board or a Committee on specific or unique aspects of OPG's operations, for example OPG hedging activities and controls, and nuclear waste management,
- Approximately every other Board meeting is preceded by a Board education session. Suggestions for director education sessions are submitted to the Chair of the Governance and Nominating Committee,
- Plant tours to major facilities are arranged in conjunction with director orientation sessions as well as the holding of Board meetings at OPG facilities,
- OPG sponsors director attendance at the Institute of Corporate Directors/Rotman Business School Director College, or equivalent, and
- OPG also provides support to directors for attendance at conferences related to OPG's business or continuing education sessions related to their responsibilities as directors.

Ethical Business Conduct

OPG has a policy for ethical business behaviour and a Code of Business Conduct, which is approved by the Board. The Audit and Risk Committee Charter expressly includes regular reporting by Management on the Code of Business Conduct, including reports on substantiated cases of fraud and the disposition of such cases including disciplinary action. The Audit and Risk Committee also receives an annual report on the Code of Business Conduct in order to satisfy itself that appropriate codes of conduct and compliance programs are in place and are being enforced and remedial action is being taken. A copy of OPG's Code of Business Conduct has been filed with the OSC. The Audit and Risk Committee has also established procedures for the receipt, retention and treatment of complaints received pertaining to internal accounting controls or auditing matters and the confidential anonymous submission by employees concerning such matters. The Audit and Risk Committee also received a report on the communication to employees of the new procedures.

The Board has accepted a recommendation from the Governance and Nominating Committee for the implementation of an annual process of written disclosure by directors of information in order to: (i) identify potential conflicts of interest for the purposes of complying with the Ontario Business Corporations Act, (ii) validate their independence and financial literacy for the purposes of complying with securities regulations related to Boards and Audit Committees, and (iii) satisfy other disclosures and filings.

Nomination of Directors

In the spring of 2004, the Board established a Search Committee and hired an independent search firm to assist in the identification of skills, attributes and business experience that would be appropriate for the OPG Board of Directors, given the nature, complexity and risk of OPG's business. Upon approval by the Board of the appropriate skills and competencies profile, the search firm recommended candidates to be interviewed by the Search Committee. The Search Committee made its recommendations to the Board, and a slate of proposed directors was submitted to the Shareholder in the fall of 2004. The Search Committee was disbanded and directors were elected to the Board by the Shareholder in September and October 2004, and February 2005.

The Board recently established a permanent Governance and Nominating Committee, and among its responsibilities are to: (i) develop and maintain list of optimum skills which the Board should collectively possess, (ii) recommend a process to identify director candidates, (iii) recommend selection criteria, (iv) identify director candidates to the Board and (v) recommend to the Board the candidates to stand for election. The Board submits recommended candidates to the Shareholder. Nominations of directors by the Shareholder are also reviewed by the Governance and Nominating Committee.

In December of 2005, the Shareholder appointed an additional director to the OPG Board. The Board now consists of 12 directors.

Compensation

Director Compensation

In the spring of 2005, the Compensation and Human Resources Committee of the Board retained an independent advisor to benchmark OPG director compensation against companies similar in size, business complexity and risk profile. The Compensation and Human Resources Committee submitted its recommendations for director compensation to the Board for approval. The Board Chair subsequently informed the Shareholder.

The recently established Governance and Nominating Committee has assumed responsibility for monitoring and reviewing at least annually the level and nature of compensation of directors to ensure that it is both appropriate to the responsibilities and risks assumed, and competitive with other comparable organizations.

CEO Compensation

In the spring of 2005, the Compensation and Human Resources Committee of the Board retained an independent advisor to benchmark an appropriate compensation package for the recruitment of the President and CEO, given the nature, complexity and risk profile of OPG's business. The Compensation and Human Resources Committee submitted its recommendation to the Board for approval. The Board Chair subsequently informed the Shareholder.

The Compensation and Human Resources Committee of the Board oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Compensation and Human Resources Committee seeks input from an independent advisor with regard to monitoring and benchmarking compensation developments.

Board Committees

The Board has established six committees to focus on areas critical to the Company:

Audit and Risk Committee

The Committee is responsible for reviewing the Company's regulatory filings including financial statements, MD&A, and press releases prior to their disclosures to the public. The Committee is also responsible for overseeing the internal audit function, the work of external auditors including their nomination and compensation, that the Company has adequate controls in the financial reporting process and the risk management process, and is in compliance with regulatory and internal policies. The Committee is also responsible for overseeing OPG's policy on ethical behaviour and the Code of Business Conduct, including reports on compliance programs, substantiated cases of fraud and the disposition of such cases including disciplinary action.

Governance and Nominating Committee

The Committee develops governance principles for OPG that are consistent with high standards of corporate governance and reviewing and assessing on an ongoing basis OPG's system of corporate governance with a view to maintaining these high standards. The Committee identifies and recommends candidates for election or appointment to the Board to be put before the Shareholder in the event of a vacancy on the Board. Finally, the Committee reviews and recommends OPG's processes for director orientation, assessment, and compensation.

Nuclear Operations Committee

This Committee is responsible for oversight of safe and efficient operations of OPG's nuclear business, regulatory compliance of OPG's nuclear facilities, review of reports from independent oversight of OPG's nuclear operations, reviews of OPG nuclear management and organization matters, security of OPG's nuclear facilities and substances, and oversight of OPG's nuclear waste and decommissioning liabilities and management.

Investment Funds Oversight Committee

This Committee assists the Board in fulfilling its responsibilities for the OPG Pension Fund and the Used Fuel Fund and Decommissioning Fund. The Committee provides oversight of the investment of assets, investment-related liabilities and the management of any surplus (deficit) of the funds. Specifically the Committee: reviews the investment policies, risks and the asset mix; approves annual performance objectives for the investment portfolios; and monitors the performance of the funds.

Compensation and Human Resources Committee

This Committee focuses on human resources related areas including compensation practices, CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review including succession planning, human resources policies related to employee complaints, diversity and pay equity, organizational design, labour relations, pension plans and policies, and Board compensation, education and evaluation programs.

Major Projects Committee

This Committee assists the Board in providing oversight of major non-nuclear electricity supply projects, including project development, contracting, financing, and construction monitoring.

Assessments

In 2005, the Board established an annual evaluation process for the Board and Board Committees. The annual Committee Evaluation, consisting of the completion of confidential questionnaires regarding Committee Charters and operations, was launched by the Governance and Nominating Committee in November 2005. The results and recommendations for enhancing oversight will be reported to the Board by the Chair of the Governance and Nominating Committee early in 2006. The Board will be undertaking the assessment of the Board and its Charter in 2006.

Audit and Risk Committee Information

Multilateral Instrument 52-110, Audit Committees (the "Instrument") has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective and independent audit committees, which enhance the quality of financial disclosure and ultimately foster increased investor confidence in Canada's capital markets. Information on OPG's Audit and Risk Committee, which includes the text of the Audit and Risk Committee Charter, updated during 2005, is as follows:

Audit and Risk Committee Charter

Purpose

The purpose of the Audit and Risk Committee (the "Committee") is to assist the Board in fulfilling its oversight responsibilities by reviewing, advising and making recommendations to the Board on:

- The integrity, quality and transparency of the Company's financial information,
- The adequacy of the financial reporting process,
- The systems of internal controls and risk management, and the Company's related principles, policies and procedures which Management have established,
- The performance of the Company's internal audit function and the external auditors,
- The external auditors' qualifications and independence,
- The Company's compliance with related legal and regulatory requirements and internal policies, and
- The promotion of a culture of ethical business conduct and compliance with OPG's Code of Business Conduct.

The function of the Audit and Risk Committee is oversight. Management is responsible for the preparation, presentation and integrity of the consolidated financial statements of the Company. Management of the Company is responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations.

Organization

Members

The Audit and Risk Committee shall consist of three or more independent Directors appointed by the Board of Directors, none of whom shall be employees of the Company or any of the Company's affiliates. A majority of the members of the Committee, but not less than two, will constitute a quorum.

As a venture issuer, OPG is exempt from the statutory requirements of Multilateral Instrument 52-110 requiring members of Audit Committees to be independent. However, OPG considers such independence to be "best practice" and, therefore, each of the members of the Audit and Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing the Company.

The Board of Directors shall designate one member of the Audit and Risk Committee as the Committee Chair. Members of the Audit and Risk Committee shall serve at the pleasure of the Board of Directors for such term or terms as the Board of Directors may determine. The Board of Directors shall confirm that each member of the Audit and Risk Committee is financially literate as such qualification is interpreted by the Board of Directors in its business judgment and in compliance with Multilateral Instrument 52-110 and its Companion Policy.

Meetings

The Committee will meet at least quarterly or more frequently as circumstances require and at any time at the request of a member. The Committee will meet regularly and at least annually with the external auditors, the internal auditors and Management in separate sessions to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in the Company's financial information or regulatory filings any report from the Audit and Risk Committee required by applicable laws and regulations and stating among other things whether the Audit and Risk Committee has:

- Reviewed and discussed the audited consolidated financial statements with Management,
- Discussed pertinent matters with the internal and external auditors,
- Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence, and
- Recommended to the Board of Directors that the audited consolidated financial statements be included in the Company's Annual Report.

Authority

While the Audit and Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit and Risk Committee to plan or conduct audits or risk assessments, or to determine that the Company's consolidated financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and the external auditor.

In carrying out its oversight responsibilities, the Audit and Risk Committee and the Board will necessarily rely on the expertise, knowledge and integrity of the Company's Management, and internal and external auditors.

The Audit and Risk Committee shall have the authority to set and pay the compensation for any advisors employed by the Committee.

The Audit and Risk Committee shall have the authority to communicate directly with the internal and external auditors.

Delegation of Authority

The Committee may delegate to any employee of OPG or a sub-committee the authority to: (i) execute or carry out any decision of the Committee; and/or (ii) exercise any right, power or function of the Committee on such terms and conditions and within such limits as the Committee may establish, except that the Committee may not delegate its oversight responsibilities.

Access to Management and Outside Advisors

The Audit and Risk Committee shall have unrestricted access to members of Management and relevant information. The Audit and Risk Committee may retain independent counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

Committee Responsibilities and Duties

The Committee shall:

General

- Conduct or authorize investigations into any matters within the Committee's scope of responsibilities,
- Review and recommend approval to the Board, the appointment or replacement of the CFO and the Chief Risk Officer (CRO), and
- Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company.

Risk Management and Internal Controls

- Review and evaluate the Company's policies and processes for assessing significant risks or exposures and the steps Management has taken to monitor and control such risks to the Company, including the organizational structure and the adequacy of resources,
- Consider and review with the CRO and Management the critical risks to the Company, the potential impact of such risks, and related mitigation,
- Ascertain whether the Company has an effective process for determining risks and exposure from actual and potential litigation and claims relating to non-compliance with laws and regulations,
- Review with Management, reports demonstrating compliance with risk management policies,
- Review with the Company's General Counsel and others any legal, tax, or regulatory matters that may have a material impact on Company operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty,
- Review with Management, internal audit, and the external auditors, the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls,
- Review disclosures made by the CEO and CFO during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in the Company's internal controls, and
- Review the expenses of the Chairman, CEO and the CEO's direct reports on a semi-annual basis, and of any other senior officers and employees the Committee considers appropriate.

Internal Audit

- Evaluate the internal audit process and define expectations in establishing the annual internal audit plan and the focus on risk, including the organizational structure and the adequacy of resources,
- Approve the Charter of the internal audit function annually,
- Evaluate the audit scope and role of internal audit, and
- Consider and review with the CRO and Management:
  - Significant findings and Management's response including the timetable for implementation of Management Actions to correct weaknesses,
  - Any difficulties encountered in the course of their audit (such as restrictions on the scope of their work or access to information),
  - Any changes required in the planned scope of the audit plan, and
  - The internal audit budget.

External Auditor

- Recommend to the Board of Directors the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, and the compensation of the external auditor,
- Oversee the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, including the resolution of disagreements between Management and the external auditor regarding financial reporting,
- Review the independence and qualifications of the external auditor,
- At least annually, obtain and review a report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and the Company,
- Review the scope and approach of the annual audit plan with the external auditors,
- Discuss with the external auditor the quality and acceptability of the Company's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management,
- Assess the external auditor's process for identifying and responding to key audit and internal control risks,
- Ensure the rotation of the lead audit partner every five years and other audit partners every seven years, and consider regular rotation of the audit firm,
- Evaluate the performance of the external auditor annually and present its findings to the Board of Directors,
- Determine which non-audit services the external auditor is prohibited by law or regulation, or as determined by the Audit and Risk Committee, from providing and pre-approve all services provided by the external auditors. The Committee may delegate such pre-approval authority to a member of the Committee. The decision of any Committee member to whom pre-approval authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting, and
- Review and approve all related party transactions.

Financial Reporting

- Review with Management and the external auditors the Company's interim financial information and disclosures under MD&A and earnings press release, prior to filing,
- Satisfy itself that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's consolidated financial statements, other than the public disclosure referred to above, and periodically assess the adequacy of those procedures,
- Review with Management and the external auditors, at the completion of the annual audit:
  - The Company's annual financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by the Company or that the Company otherwise files with the OSC,
  - The external auditors' audit of the consolidated financial statements and their report,
  - Any significant changes required in the external auditors' audit plan,
  - Any difficulties or disputes with Management encountered during the audit,
  - The Company's accounting principles, and
  - Other matters related to conduct, which should be communicated to the Committee under generally accepted auditing standards.
- Review significant accounting and reporting issues and understand their impact on the consolidated financial statements. These include complex or unusual transactions and highly judgmental areas; major issues regarding accounting principles and financial presentations, including significant changes in the Company's selection or application of accounting principals; and the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements, on the consolidated financial statements of the Company,
- Review analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative generally accepted accounting principles methods, and
- Advise Management, based upon the Audit and Risk Committee's review and discussion, whether anything has come to the Committee's attention that causes it to believe that the consolidated financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

Compliance with Code of Business Conduct

- Review the administration of and compliance with the Company's Code of Business Conduct to ensure that appropriate codes of conduct and compliance programs are in place, are being enforced and remedial action is being taken, as well as the process for communicating the Code of Business Conduct to Company personnel, and
- Monitor through regular updates from Management regarding compliance matters.

Treatment of Complaints

- Establish procedures for the receipt, recording and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters, and
- Establish procedures for the confidential and anonymous submission by employees of concerns regarding accounting or auditing matters of the Company.

Annual Review and Assessment

The Committee shall conduct an annual review and assessment of its performance, including a review of its compliance with this Charter, in accordance with the evaluation process approved by the Board.

The Committee shall also review and assess the adequacy of this Charter on an annual basis taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship, and if appropriate, shall recommend changes to the Board.

Composition of the Audit and Risk Committee

Each Audit and Risk Committee member named below is independent and financially literate.

Gary Kugler

Dr. Gary Kugler is the retired Senior Vice President, Nuclear Products and Services of Atomic Energy of Canada, Limited (AECL), where he was responsible for all of AECL's commercial operations, including nuclear power plant sales and services world-wide. During his 34 years with AECL, he also held various technical, project management, and business development positions. Prior to joining AECL, he served as a pilot in the Canadian air force. Dr. Kugler holds a Bachelor of Science degree in honours physics and a Ph.D. in nuclear physics from McMaster University.

M. George Lewis – Chair

George Lewis is Chairman and Chief Executive Officer of RBC Asset Management Inc., Mr. Lewis is also Executive Vice President, Wealth Management for the Personal and Business Canada division of RBC FG, Canada's largest bank. Formerly he was Managing Director, Head of Institutional Equity Sales, Trading and Research with RBC Capital Markets and was Canada's top-rated analyst for three consecutive years. He has extensive experience in the investment industry and has a Master of Business Administration degree with distinction from Harvard University, a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto and is a chartered financial analyst and chartered accountant.

C. Ian Ross

Ian Ross served at the Richard Ivey School of Business at the University of Western Ontario from 1997 to September 2003. Most recently he held the position of Senior Director, Administration in the Dean's Office, and was also Executive in Residence for the School's Institute for Entrepreneurship, Innovation and Growth. He has served as Governor and President and CEO of Ortech Corporation; Chairman, President and CEO of Provincial Papers Inc.; and President and CEO of Paperbound Industries Corp. Mr. Ross currently serves as a Director for a number of corporations including World Heart Corporation, GrowthWorks Canadian Fund Ltd., PetValu Canada Inc., Comcare Health Services and eJust Systems (formerly Praeda Managements Systems). He is also a member of the Law Society of Upper Canada.

David G. Unruh

David Unruh is a lawyer currently serving as a director of Westcoast Energy Inc. and Union Gas Limited, both Duke Energy companies. Mr. Unruh is also a director of Export Development Canada, Pacific Northern Gas Ltd., Corriente Resources Inc., The Wawanesa Mutual Insurance Company, The Wawanesa General Insurance Company, The Wawanesa Life Insurance Company, and RAV Project Management Company. Prior to this, Mr. Unruh served as Vice Chairman of Westcoast Energy Inc. and Union Gas Limited, before that as Senior Vice President and General Counsel for Houston-based Duke Energy Gas Transmission and, before that as Senior Vice President, Law and Corporate Secretary of Westcoast Energy Inc. Mr. Unruh practiced corporate and commercial law in Winnipeg, Manitoba before joining Westcoast Energy Inc. in Vancouver, British Columbia in 1993.

Audit and Risk Committee Oversight

There have been no recommendations of our Audit and Risk Committee to nominate or compensate an external auditor which have not been adopted by our Board of Directors.

Reliance on Certain Exemptions

There has been reliance upon the exemption in Section 6.1 of Multilateral Instrument 52-110 Audit Committees ("Instrument 52-110") as it relates to Section 5, *Reporting Obligations*. OPG has, however, in accordance with Section 6.2 of Instrument 52-110, provided the disclosure required by Form 52-110F2.

Pre-Approval Policies and Procedures

In accordance with the provisions of its mandate, the Audit and Risk Committee ratifies all non-audit services to be provided to the Company by its external auditor.

External Auditor Service Fees

The following fees were billed by Ernst & Young LLP:

(thousands of dollars)	**2005**	2004
Audit Fees	**1,227**	1,267
Audit-Related Fees	**277**	995
Tax Fees and Other	**320**	122

Audit Fees
These fees included the audit of OPG's consolidated financial statements, quarterly reviews of the financial statements, pension fund audit, and the audits of the financial statements of certain subsidiaries.

Audit-Related Fees
These fees included work with respect to internal controls, accounting assistance, French translation of consolidated financial statements and MD&A, and special audits and reviews. During 2005, OPG has employed the services of other professional advisers, particularly in the areas of internal controls and accounting assistance.

Tax Fees and Other
These fees included tax services related to a U.S. Federal tax review and other income tax matters.

Internal Controls over Financial Reporting and Disclosure Controls

OPG continues to enhance the process by which it designs and tests the operating effectiveness of internal controls over financial reporting. Concurrently with this process, OPG has evaluated disclosure controls and procedures and concluded that these controls and procedures operated effectively at the end of the period covered by the annual filing. Concurrent with the filing of the MD&A, OPG has provided the CEO and CFO certification required by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Interim and Annual Filings ("Instrument 52-109"), around the design and operating effectiveness of disclosure controls and procedures, effective December 31, 2005.

OPG is working toward providing support for the full certification detailed in Instrument 52-109 by continuing its project to document, test and evaluate internal controls over financial reporting and to design remedies where deficiencies are noted. The full certification for reporting issuers around the responsibility for establishing and maintaining internal controls over financial reporting, the design of those controls, and the disclosure in the MD&A of material changes in those controls, is effective December 31, 2006. The project team continues to work with process owners to address all findings identified during the 2005 testing cycle, which incorporated significant financial processes, disclosure controls, and entity level controls.

OPG is also working to implement a program designed to meet the full certification requirements for non-venture issuers identified in Instrument 52-109. These requirements, which are effective December 31, 2006, add disclosure to the Audit and Risk Committee of significant and material weakness and disclosure of fraud that involves individuals who have a significant role in internal controls over financial reporting. In addition, OPG is monitoring the management and audit report requirements for non-venture issuers identified in the proposed Multilateral Instrument 52-111, Reporting on Internal Control over Financial Reporting.

Supplemental Earnings Measures

In addition to providing net income in accordance with Canadian generally accepted accounting principles, OPG's MD&A, consolidated financial statements for the year ended December 31, 2005 and 2004 and the notes thereto, present non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") and therefore, may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements and notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) Gross margin is defined as revenue less Market Power Mitigation Agreement and revenue limit rebates and fuel expense.

(2) Restructuring expenses are defined as costs incurred to implement a fundamental and material change to the operating and/or management structures of the Company. Restructuring expenses may include severance costs, termination benefits and related pension and OPEB expenses, professional fees, travel costs and other incremental costs directly associated with the restructuring activities.

(3) Earnings is defined as net income.

For further information, please contact:

Investor Relations	416-592-6700 1-866-592-6700 investor.relations@opg.com
Media Relations	416-592-4008 1-877-592-4008 www.opg.com
Other	www.sedar.com

Statement of Management's Responsibility for Financial Information

Ontario Power Generation Inc.'s ("OPG") management is responsible for presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and the requirements of the Ontario Securities Commission ("OSC"), as applicable. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal control and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and sound and conservative accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

We, as OPG's Chief Executive Officer and Chief Financial Officer, will certify OPG's annual disclosure document filed with the OSC, which includes attesting to the effectiveness of OPG's disclosure controls and procedures, as required by Multilateral Instrument 52-109.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jim Hankinson
President and Chief Executive Officer

Donn W.J. Hanbidge
Chief Financial Officer

February 7, 2006

Auditors' Report

To the Shareholder of Ontario Power Generation Inc.

We have audited the consolidated balance sheets of Ontario Power Generation Inc. as at December 31, 2005 and 2004 and the consolidated statements of income, retained earnings (deficit) and cash flows for the years then ended. These consolidated financial statements are the responsibility of Ontario Power Generation Inc.'s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Toronto, Canada
February 7, 2006

Consolidated Statements of Income

Years Ended December 31 (millions of dollars except where noted)	2005	2004
Revenue		
Revenue before Market Power Mitigation Agreement and revenue limit rebates	**6,949**	6,072
Market Power Mitigation Agreement rebate (note 17)	**(412)**	(1,154)
Revenue limit rebate (note 18)	**(739)**	–
	5,798	4,918
Fuel expense	**1,297**	1,153
Gross margin	**4,501**	3,765
Expenses		
Operations, maintenance and administration	**2,516**	2,594
Depreciation and amortization (note 5)	**753**	765
Accretion on fixed asset removal and nuclear waste management liabilities	**476**	453
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(381)**	(313)
Property and capital taxes	**107**	103
Restructuring	**10**	20
	3,481	3,622
Income before the following:	**1,020**	143
Impairment of long-lived assets (note 5)	**265**	–
Other income	**–**	(8)
Income before interest, income taxes and extraordinary item	**755**	151
Net interest expense	**197**	189
Income (loss) before income taxes and extraordinary item	**558**	(38)
Income tax expense (recovery)		
Current	**80**	21
Future (note 10)	**38**	(101)
	118	(80)
Income before extraordinary item	**440**	42
Extraordinary item (note 10)	**74**	–
Net income	**366**	42
Basic and diluted income per common share before extraordinary item (dollars)	**1.72**	0.16
Basic and diluted income per common share (dollars)	**1.43**	0.16
Common shares outstanding (millions)	**256.3**	256.3

See accompanying notes to the consolidated financial statements

Consolidated Statements of Retained Earnings (Deficit)

As at December 31 (millions of dollars)	2005	2004
Deficit, beginning of year	**(105)**	(147)
Net income	**366**	42
Retained earnings (deficit), end of year	**261**	(105)

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

Years Ended December 31 (millions of dollars)	2005	2004
Operating activities		
Net income	**366**	42
Adjust for non-cash items:		
Depreciation and amortization	**753**	765
Accretion on fixed asset removal and nuclear waste management liabilities	**476**	453
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(381)**	(313)
Pension cost	**115**	92
Other post employment benefits and supplementary pension plans	**181**	157
Future income taxes	**38**	(101)
Transition rate option contracts	**(36)**	(52)
Provision for restructuring	**10**	20
Mark-to-market adjustment on energy contracts	**18**	5
Provision for used nuclear fuel	**28**	28
Impairment of long-lived assets	**265**	–
Excess inventory write-off	**57**	–
Extraordinary item	**74**	–
Regulatory assets and liabilities	**7**	–
Other	**22**	26
	1,993	1,122
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(454)**	(454)
Expenditures on fixed asset removal and nuclear waste management	**(90)**	(71)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**23**	19
Contributions to pension fund	**(254)**	(154)
Expenditures on other post employment benefits and supplementary pension plans	**(65)**	(60)
Expenditures on restructuring (note 15)	**(18)**	(51)
Net changes to other long-term assets and liabilities	**(87)**	(26)
Changes in non-cash working capital balances (note 25)	**153**	(99)
Cash flow provided by operating activities	**1,201**	226
Investing activities		
Investment in regulatory assets (note 6)	**(265)**	–
Investment in fixed assets	**(498)**	(561)
Proceeds on sale of other fixed assets	**3**	18
Cash flow used in investing activities	**(760)**	(543)
Financing activities		
Issuance of long-term debt (note 8)	**495**	13
Repayment of long-term debt (note 8)	**(4)**	(6)
Net increase (decrease) in short-term notes (note 7)	**(26)**	26
Cash flow provided by financing activities	**465**	33
Net increase (decrease) in cash and cash equivalents	**906**	(284)
Cash and cash equivalents, beginning of year	**2**	286
Cash and cash equivalents, end of year	**908**	2

See accompanying notes to the consolidated financial statements

Consolidated Balance Sheets

As at December 31 (millions of dollars)	2005	2004
Assets		
Current assets		
Cash and cash equivalents	**908**	2
Accounts receivable (note 4)	**538**	346
Future income taxes (note 10)	**18**	44
Fuel inventory	**581**	569
Materials and supplies	**115**	92
	2,160	1,053
Fixed assets (note 5)		
Property, plant and equipment	**15,172**	15,114
Less: accumulated depreciation	**3,760**	3,174
	11,412	11,940
Other long-term assets		
Deferred pension asset (note 11)	**663**	524
Nuclear fixed asset removal and nuclear waste management funds (note 9)	**6,788**	5,976
Long-term materials and supplies	**273**	281
Regulatory assets (note 6)	**266**	–
Long-term accounts receivable and other assets	**61**	56
	8,051	6,837
	21,623	19,830

See accompanying notes to the consolidated financial statements

Consolidated Balance Sheets

As at December 31 (millions of dollars)	2005	2004
Liabilities		
Current liabilities		
Accounts payable and accrued charges (notes 15 and 16)	**958**	949
Market Power Mitigation Agreement rebate payable (note 17)	**–**	439
Revenue limit rebate payable (note 18)	**739**	–
Short-term notes payable (note 7)	**–**	26
Long-term debt due within one year (note 8)	**806**	5
Deferred revenue due within one year	**12**	12
Income and capital taxes payable (note 10)	**81**	12
	2,596	1,443
Long-term debt (note 8)	**3,089**	3,399
Other long-term liabilities		
Fixed asset removal and nuclear waste management (note 9)	**8,759**	8,339
Other post employment benefits and supplementary pension plans (note 11)	**1,212**	1,105
Long-term accounts payable and accrued charges	**183**	212
Deferred revenue	**144**	156
Future income taxes (note 10)	**241**	155
Regulatory liabilities (note 6)	**12**	–
	10,551	9,967
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings (deficit)	**261**	(105)
	5,387	5,021
	21,623	19,830

Commitments and Contingencies (notes 2, 5, 7, 8, 9, 10, 12 and 14)

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

Honourable Jake Epp
Chairman

M. George Lewis
Director

Notes to the Consolidated Financial Statements for the Years Ended December 31, 2005 and 2004

1 Description of Business

Ontario Power Generation Inc. was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario). As part of the reorganization of Ontario Hydro, under the *Electricity Act, 1998* and the related restructuring of the electricity industry in Ontario, Ontario Power Generation Inc. and its subsidiaries (collectively "OPG" or the "Company") purchased and assumed certain assets, liabilities, employees, rights and obligations of the electricity generation business of Ontario Hydro on April 1, 1999 and commenced operations on that date. Ontario Hydro has continued as Ontario Electricity Financial Corporation ("OEFC"), responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations.

2 Basis of Presentation

These consolidated financial statements were prepared in accordance with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires Management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

The consolidated financial statements include the accounts of OPG and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant intercompany transactions have been eliminated on consolidation.

Certain of the 2004 comparative amounts have been reclassified from financial statements previously presented to conform to the 2005 financial statement presentation.

3 Summary of Significant Accounting Policies

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost or market.

Interest earned on cash and cash equivalents and short-term investments of $13 million (2004 – $5 million) at an average effective rate of 2.8 per cent (2004 – 2.2 per cent) is offset against interest expense in the consolidated statements of income.

Sales of Accounts Receivable

Asset securitization involves selling assets such as accounts receivable to independent entities or trusts, which buy the receivables and then issue interests in them to investors. These transactions are accounted for as sales, given that control has been surrendered over these assets in return for net cash consideration. For each transfer, the excess of the carrying value of the receivables transferred over the estimated fair value of the proceeds received is reflected as a loss on the date of the transfer, and is included in net interest expense. The carrying value of the interests transferred is allocated to accounts receivable sold or interests retained according to their relative fair values on the day the transfer is made.

Fair value is determined based on the present value of future cash flows. Cash flows are projected using OPG's best estimates of key assumptions, such as discount rates, weighted average life of accounts receivable and credit loss ratios.

As part of the sales of accounts receivable, certain financial assets are retained and consist of interests in the receivables transferred. Any retained interests held in the receivables are accounted for at cost. The receivables are transferred on a fully serviced basis and do not create a servicing asset or liability.

Inventories
Fuel inventory is valued at weighted average cost.

Materials and supplies are valued at the lower of average cost or net realizable value with the exception of critical replacement parts which are unique to nuclear and fossil-fuelled generating stations. The cost of the critical replacement parts inventory is charged to operations on a straight-line basis over the remaining life of the related facilities and is classified in long-term assets.

Fixed Assets and Depreciation
Property, plant and equipment are recorded at cost. Interest costs incurred during construction are capitalized as part of the cost of the asset based on the interest rate on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are also charged to depreciation expense. Repairs and maintenance are expensed when incurred.

Fixed assets are depreciated on a straight-line basis except for computers, and transport and work equipment, which are depreciated on a declining balance basis as noted below:

Darlington and Pickering B nuclear generating stations	25 years
Pickering A nuclear generating station	42 to 44 years[1]
Fossil generating stations	40 to 50 years[2]
Hydroelectric generating stations	100 years
Administration and service facilities	50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years

1. Units 1 and 4 of the Pickering A station are depreciated over a longer operating life as a result of the completion, during the 1980s, of the retubing of the Pickering A station and the refurbishment of Units 1 and 4, completed in 2005 and 2003 respectively.
2. Commencing January 1, 2004, the coal-fired generating stations will be depreciated over the period from 2004 to 2007, due to the expected shutdown of these stations by the end of 2007, with the exception of the Nanticoke generating station which will be depreciated over the period to 2008.

Impairment of Fixed Assets
OPG evaluates its property, plant and equipment for impairment whenever conditions indicate that estimated undiscounted future net cash flows may be less than the net carrying amount of assets. In cases where the undiscounted expected future cash flows are less than the carrying amount, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available.

Long-Term Portfolio Investments
Long-term portfolio investments, other than investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV"), are stated at amortized cost and include the nuclear fixed asset removal and nuclear waste management funds. Gains and losses on long-term investments are recognized in other income when investments are sold. When a decline in the value of investments occurs, which is considered to be other than temporary, a provision for loss is established.

Investments owned by OPGV are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated based on readily available market information or using estimation techniques based on historical performance.

Fixed Asset Removal and Nuclear Waste Management Liability

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liability is increased by the present value of the variable cost portion of the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Expenses relating to low and intermediate level waste are charged to depreciation and amortization expense. Expenses relating to the disposal of nuclear used fuel are charged to fuel expense. The liability may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liability, a gain or loss would be recorded.

Accretion arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time. The resulting expense is included in operating expenses.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining useful life of the related fixed assets and is included in depreciation expense.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province of Ontario, OPG established the Used Fuel Fund and a Decommissioning Fund (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund expenditures associated with the disposal of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

The Nuclear Funds are invested in fixed income and equity securities, which OPG records as long-term investments and accounts for at their amortized cost value. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements.

Revenue Recognition

All of OPG's electricity generation is sold into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO"). Prior to April 1, 2005, revenue was recorded as electricity was generated and metered based on the spot market sales price, net of the Market Power Mitigation Agreement rebate and hedging activities. At each balance sheet date, OPG computed the average spot energy price that prevailed since the beginning of the current settlement period and recognized a Market Power Mitigation Agreement rebate if the average price exceeded 3.8¢/kilowatt-hour ("kWh"), based on the amount of energy subject to the rebate.

Effective April 1, 2005, the generation from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. OPG continues to receive the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit. As a result, energy revenue generated from the nuclear facilities is recognized based on a regulated price of 4.95¢/kWh. The regulated price received by OPG for the first 1,900 megawatt hours (MWh) of production from the regulated hydroelectric facilities in any hour is 3.3¢/kWh. Any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price. The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station, Transition – Generation Corporation Designated Rate Options ("TRO") volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of 4.7¢/kWh. This revenue limit was originally established for a period of 13 months ending April 30, 2006.

OPG also sells into, and purchases from, interconnected markets of other provinces and the U.S. northeast and midwest. All contracts that are not designated as hedges are recorded in the consolidated balance sheets at market value with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $228 million in 2005 and $170 million in 2004 were netted against revenue.

OPG derives non-energy revenue under the terms of a lease arrangement with Bruce Power L.P. ("Bruce Power") related to the Bruce nuclear generating stations. This includes lease revenues, interest income and revenues for engineering analysis and design, technical and ancillary services. OPG also earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, non-energy revenue includes isotope sales to the medical industry and real estate rentals. Revenues from these activities are recognized as services are provided or products are delivered.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at year-end exchange rates. Any resulting gain or loss is reflected in other revenue.

Derivatives

OPG is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the wholesale price of electricity, OPG enters into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized in income over the term of the contract when the underlying hedged transactions occur. These gains or losses are included in unregulated revenue and are not recorded on the consolidated balance sheets. All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in other revenue.

OPG also enters into derivative contracts with major financial institutions to manage the Company's exposure to foreign currency movements. Foreign exchange translation gains and losses on these foreign currency denominated derivative contracts are recognized as an adjustment to the purchase price of the commodity or goods received.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded through net income in the period incurred.

OPG utilizes emission reduction credits ("ERCs") and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances are held in inventory and charged to OPG's operations at average cost as part of fuel expense as required. Options to purchase ERCs are accounted for as derivatives and are recorded at estimated market value.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. When such derivative instrument ceases to exist or be effective as a hedge, or when designation of a hedging relationship is terminated, any associated deferred gains or losses are carried forward to be recognized in income in the same period as the corresponding gains or losses associated with the hedged item. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income.

Research and Development

Research and development costs are charged to operations in the year incurred. Research and development costs incurred to discharge long-term obligations such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Pension and Other Post Employment Benefits

OPG's post employment benefit programs include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, group life insurance, health care and long-term disability benefits. OPG accrues its obligations under pension and other post employment benefit ("OPEB") plans. The obligations for pension and other post retirement benefit costs are determined using the projected benefit method pro-rated on service. The obligation for long-term disability benefits is determined using the projected benefit method on a terminal basis. The obligations are affected by salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions. The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields.

Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPEB plan amendments are amortized on a straight-line basis over the expected average remaining service life of the employees covered by the plan, since OPG will realize the economic benefit over that period. Due to the long-term nature of post-employment liabilities, the excess of the net cumulative unamortized gain or loss, over 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets, is also amortized over the expected average remaining service life.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Taxes

Under the *Electricity Act, 1998*, OPG is responsible for making payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG uses the liability method of accounting for income taxes for the unregulated segments of its business. Under the liability method, income taxes are recognized as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value in the balance sheet, the carry-forward of unused tax losses and income tax reductions. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered 'more likely than not', a valuation allowance is established.

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes related to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that these future income taxes are expected to be recovered in the regulated rates charged to future customers.

OPG makes payments in lieu of property tax on its nuclear and fossil-fuelled generating assets to the OEFC, and also pays property taxes to municipalities.

OPG pays charges on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense.

Business Segments

As noted in Note 19, OPG changed its definition of business segments on April 1, 2005 from Generation and Energy Marketing to Regulated – Nuclear, Regulated – Hydroelectric and Unregulated Generation. OPG will continue to report other activities, including trading activities, which were previously reported separately, in the Other category. As a result of this change in definition, OPG has reclassified the comparative periods to be consistent with the current presentation of business segments.

Changes in Accounting Policies

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* (Bill 100) received Royal Assent. A regulation made pursuant to that statute in February 2005 provides that OPG receive regulated prices beginning April 1, 2005, for its baseload hydroelectric and nuclear facilities. This includes electricity generated by Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear generating stations.

OPG's regulated prices were determined by the Province based on total projected production and costs of operation, plus the cost of capital including an average five per cent return on equity. The initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will establish new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend these initial prices.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates all market participants in the province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the consolidated financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, then OPG may defer those costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, then OPG reports a regulatory liability. Also, if the regulation provides for lesser or greater than planned revenue to be received or returned by OPG through future rates, then OPG recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation.

Income Taxes

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes related to the rate regulated segments of its business using the taxes payable method.

New Accounting Recommendations

Consolidation of Variable Interest Entities

In September 2004, the CICA amended Accounting Guideline 15, *Consolidation of Variable Interest Entities*, originally issued in June 2003, to harmonize with the revised Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46R"). The new guideline requires the consolidation of variable interest entities ("VIEs") by the primary beneficiary. A VIE is an entity where (i) its equity investment at risk is insufficient to permit the entity to finance its activities without additional subordinated support from others and/or where certain essential characteristics of a controlling financial interest are not met, and (ii) it does not meet specified exemption criteria. The primary beneficiary is the enterprise that will absorb or receive the majority of the VIEs' expected losses, expected residual returns, or both.

OPG is involved with various joint venture and other arrangements and has sold trade receivables under an asset securitization arrangement. OPG concluded that the joint venture and other arrangements with which it is involved are not VIEs, and that it is not the primary beneficiary of, nor does it have a significant variable interest in, the trust to which it sold trade receivables.

Investment Companies

In January 2004, the CICA issued Accounting Guideline 18, *Investment Companies* ("AcG-18"). The new guideline requires investments owned by entities that meet the investment companies criteria, to be recorded at fair value with gains and losses recognized in net income. During 2005, OPG applied the new guideline to investments that its owns.

Future Accounting Policy Changes

In 2005, the CICA issued three new accounting standards: Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments – Recognition and Measurement, and Handbook Section 3865, Hedges. These standards apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006.

These standards will be effective for OPG beginning in 2007. The impact of implementing these new standards on OPG's consolidated financial statements is not yet determinable as it will be dependent on outstanding positions and their fair values at the time of transition. The following provides further information on each of the three new accounting standards as they relate to OPG.

Comprehensive Income
As a result of adopting these standards, a new category, accumulated other comprehensive income, will be added to shareholder's equity on the consolidated balance sheets. Major components for this category will include unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation amounts, net of hedging, and changes in the fair value of the effective portion of cash flow hedging instruments. These amounts will be recorded in the statement of other comprehensive income until the criteria for recognition in the consolidated statement of income are met.

Financial Instruments – Recognition and Measurement
Under the new standard, for accounting purposes, financial assets will be classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities will be classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading will be measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, will be measured at amortized cost. Available-for-sale instruments will be measured at fair value with unrealized gains and losses recognized in other comprehensive income. The standard also permits designation of any financial instrument as held-for-trading upon initial recognition. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held for trading and recorded at fair value in the consolidated balance sheets.

Hedges
This new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a fair value hedging relationship, the carrying value of the hedged item is adjusted by gains or losses attributable to the hedged risk and recognized in net income. This change in fair value of the hedged item, to the extent that the hedging relationship is effective, is offset by changes in the fair value of the derivative. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative will be recognized in other comprehensive income. The ineffective portion will be recognized in net income. The amounts recognized in accumulated other comprehensive income will be reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, foreign exchange gains and losses on the hedging instruments will be recognized in other comprehensive income.

4 Sale of Accounts Receivable

On October 1, 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables. In December 2005, OPG extended the agreement to August 2009.

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust net of the undivided co-ownership interest retained by the Company. For 2005, the Company has recognized pre-tax charges of $9 million (2004 – $8 million) on such sales at an average cost of funds of 3.1 per cent (2004 – 2.6 per cent). As at December 31, 2005, OPG had sold receivables of $300 million from its total portfolio of $668 million.

The accounts receivable reported and securitized by the Company are as follows:

	Principal amount of receivables as at December 31		Average balance of receivables for year ended December 31	
(millions of dollars)	**2005**	2004	**2005**	2004
Total receivables portfolio[1]	**668**	490	**559**	470
Receivables sold	**300**	300	**300**	300
Receivables retained	**368**	190	**259**	170
Average cost of funds			**3.1%**	2.6%

1 Amount represents receivables outstanding, including receivables that have been securitized, which the Company continues to service.

An immediate 10 per cent or 20 per cent adverse change in the discount rate would not have a material effect on the current fair value of the retained interest. There were no credit losses for the year ended December 31, 2005 and 2004.

Details of cash flows from securitizations for the years ended December 31 are as follows:

(millions of dollars)	**2005**	2004
Collections reinvested in revolving sales[1]	**3,600**	3,600
Cash flows from retained interest	**3,104**	2,043

1. Given the revolving nature of the securitization, the cash collections received on the receivables securitized are immediately reinvested in additional receivables resulting in no further cash proceeds to the Company over and above the initial cash amount of $300 million. The amounts reflect the cumulative of 12 monthly amounts.

5 Fixed Assets

Depreciation and amortization expense consists of the following:

(millions of dollars)	**2005**	2004
Depreciation and amortization	**748**	758
Nuclear waste management costs	**5**	7
	753	765

Fixed assets consist of the following:

(millions of dollars)	**2005**	2004
Property, plant and equipment		
Nuclear generating stations	**4,754**	4,326
Regulated Hydroelectric generating stations	**4,379**	4,345
Unregulated Hydroelectric generating stations	**3,447**	3,432
Fossil-fuelled generating stations	**1,411**	1,596
Other fixed assets	**833**	850
Construction in progress	**348**	565
	15,172	15,114
Less: accumulated depreciation		
Generating stations	**3,497**	2,935
Other fixed assets	**263**	239
	3,760	3,174
	11,412	11,940

The asset under capital lease was $203 million in 2004 and was included in other fixed assets. There were no assets under capital lease as at December 31, 2005. Accumulated depreciation on the leased asset at December 31, 2004 was $53 million. Interest capitalized at six per cent during the years ended December 31, 2005 and 2004 was $27 million and $30 million, respectively.

Impairment of Long-Lived Assets

The accounting estimates related to asset impairment require significant management judgment to identify factors such as short and long-term forecasts for future sales prices, the supply of electricity in Ontario, inflation, fuel prices and station lives. The amount of the future cash flow that OPG will ultimately realize with respect to these assets could differ materially from the carrying values recorded in the consolidated financial statements.

Pickering A Nuclear Generating Station Units 2 and 3

OPG completed an assessment of the cost, schedule and risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. This included an assessment of the ability of these units to perform at an acceptable capability factor over the remaining 12 to 20 years of operations. This assessment incorporated recent findings from inspection programs with respect to feeder pipe and steam generator degradation mechanisms, and potential degradation of the calandria vault components, all of which could impact the future capability factor, operating costs and the life of the units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, OPG recorded an impairment loss of $63 million in the second quarter of 2005 related to the carrying amount of these two units including construction in progress. In addition to the impairment loss for these two units, OPG recorded OM&A expenses of $57 million related to the write-off of inventory identified as excess or unusable, as a result of not returning Units 2 and 3 to service.

OPG expects to recover the amounts recorded in the deferral account relating to non-capital costs incurred after January 1, 2005 associated with the return to service of Units 2 and 3. As at December 31, 2005, the deferral account relating to Units 2 and 3 was $19 million.

As a result of the decision not to proceed with the return to service of these two units, OPG continues to assess the need to provide for any additional costs, including the cost associated with preparing the units for safe storage, any impacts on cost estimates for asset retirement obligation and any other additional exit costs. Such charges may have a significant impact on operating results in future periods.

Lennox Generating Station

As a result of the Government's "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" released in September 2004 and the related contractual arrangements, future wholesale electricity market revenue is expected to be lower than previously anticipated. As a relatively high variable cost plant, the Lennox generating station will not be able to recover its fixed operating costs and its carrying value from the wholesale electricity market in the future. Given these factors, OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. In March 2005, OPG was advised by the Province that it would continue to support OPG in negotiating an arrangement that would allow for the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result of this change in circumstance, OPG recorded the impairment loss of $202 million in the first quarter of 2005. OPG has since negotiated a contract with the Independent Electricity System Operator ("IESO"), pursuant to the market rules, to recover its operating costs for a one-year period ending September 30, 2006. The contract with the IESO has been submitted to the OEB for approval.

6 Regulatory Assets and Liabilities

OPG recorded the following regulatory assets and liabilities as at December 31, 2005:

(millions of dollars)	2005
Regulatory assets	
Pickering A return to service costs deferral account	261
Ancillary services revenue variance account	5
Total regulatory assets	266
Regulatory liabilities	
Hydroelectric production variance account	4
Other	8
Total regulatory liabilities	12

Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG is required to establish a deferral account in connection with non-capital costs that are associated with the return to service of units at the Pickering A nuclear generating station. As a result, the change in accounting was prospectively adopted on January 1, 2005, with no retroactive adoption. As at December 31, 2005, the deferral account was $261 million, consisting of non-capital costs, net of amortization, of $228 million relating to Unit 1, $19 million relating to Units 2 and 3, $11 million of general return to service costs, and interest of $7 million accreted at the average cost of debt of six per cent. Upon OPG becoming subject to regulated prices established by the OEB, expected after March 31, 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years.

In November 2005, as a result of the return to commercial service of Unit 1 at the Pickering A nuclear generating station, OPG commenced amortization of the Pickering A return to service regulatory asset to OM&A expenses. The basis for amortization is consistent with that reflected in interim regulated rates and resulted in OPG recording $4 million in OM&A expenses as at December 31, 2005.

Had OPG not charged costs to the deferral account as required by the regulations, an additional $254 million would have been charged to OM&A expense and $7 million to net interest expense during 2005.

Variance Accounts

Effective April 1, 2005, in accordance with the regulations pursuant to the *Electricity Restructuring Act, 2004,* OPG was directed to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions, changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes, changes to revenues assumed for ancillary revenues from the regulated facilities, acts of God (including severe weather events), and transmission outages and transmission restrictions. OPG recorded an asset as at December 31, 2005 of $5 million, reflecting ancillary services revenue that was unfavourable compared to that forecasted for 2005. OPG recorded a liability as at December 31, 2005 of $4 million, reflecting water conditions that were favourable compared to those forecasted for 2005. Upon OPG becoming subject to regulated prices established by the OEB, the OEB is directed by the regulation to ensure recovery to the extent that the OEB is satisfied that the costs recorded in the account were prudently incurred and accurately recorded. Any balances approved by the OEB will be amortized over a period not to exceed three years.

Had OPG not accounted for the variances as a regulatory asset and liability, revenue for 2005 would have been lower by $1 million.

The other regulatory liability consists of a portion of non-regulated revenue earned by OPG's regulated assets, which will result in a reduction of future regulated rates to be established by the OEB.

7 Short-Term Credit Facilities

OPG's current 364-day term $1 billion revolving committed bank credit facility was renewed on May 24, 2005. The new facility is divided into two tranches – a $500 million 364-day term tranche maturing May 23, 2006, and a $500 million three-year term tranche maturing May 23, 2008. The total credit facility will continue to be used primarily as support for notes issued under OPG's commercial paper program. As at December 31, 2005, OPG had no borrowings outstanding under this commercial paper program (2004 – $26 million). As at December 31, 2005 and 2004, OPG had no other outstanding borrowing under this facility.

OPG also maintains $26 million (2004 – $26 million) in short-term uncommitted overdraft facilities as well as $215 million (2004 – $200 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support supplementary pension plans and is required to post the Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At December 31, 2005, there were approximately $157 million (2004 – $155 million) of Letters of Credit issued for the supplementary pension plans and collateral requirements to the LDCs.

8 Long-Term Debt

Long-term debt consists of the following:

(millions of dollars)	**2005**	2004
Notes payable to the OEFC	**3,695**	3,200
Capital lease obligations	**–**	3
Share of non-recourse limited partnership debt	**200**	201
	3,895	3,404
Less: due within one year		
Notes payable to the OEFC	**800**	–
Capital lease obligations	**–**	3
Share of limited partnership debt	**6**	2
	806	5
Long-term debt	**3,089**	3,399

Holders of the senior debt are entitled to receive, in full, amounts owing in respect of the senior debt before holders of the subordinated debt are entitled to receive any payments. The OEFC currently holds all of OPG's outstanding senior and subordinated notes.

The maturity dates as at December 31, 2005 for notes payable to the OEFC are as follows:

		Principal Outstanding (millions of dollars)		
Year of Maturity	Interest Rate (%)	Senior Notes	Subordinated Notes	Total
2006	5.70%	800	–	800
2007	5.85%	400	–	400
2008	5.90%	400	–	400
2009	6.01%	350	–	350
2010	6.00%	595	375	970
2011	6.65%	–	375	375
2012	5.72%	400	–	400
		2,945	750	3,695

In December 2004, OPG reached an agreement with the OEFC to defer payment on the $500 million principal amount of senior notes maturing in March and September 2005 by extending the maturity dates by five years. The interest rates remain unchanged. In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to $600 million, which can be drawn until March 31, 2006. In April 2005, $400 million was drawn under this facility, with a seven-year term.

The Company also reached an agreement with the OEFC to satisfy, through the issue of additional senior notes of $95 million and $98 million respectively, to mature in 2010, its $95 million interest obligation due in March 2005 and the $98 million interest obligation due in September 2005 related to the debt owing to the OEFC of $3.2 billion. As a result of an improved liquidity position, OPG elected to pay the interest due in September 2005 and not issue the $98 million note.

Interest paid in 2005 was $235 million (2004 – $218 million), of which $220 million relates to interest paid on long-term debt (2004 – $213 million).

In September 2005, OPG reached an agreement with the OEFC to provide debt financing for the Niagara tunnel project. The funding, which is up to $1 billion over the duration of the project, will be in the form of 10-year notes, which will be issued quarterly to meet the project's obligations. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates.

In October 2005, OPG reached a similar agreement with the OEFC to finance the Thunder Bay Gas Conversion project. There will be up to $95 million available to OPG under this credit facility, that will be drawn as needed over the projected two-year construction period. OPG is expected to make its first draw under this facility in the first quarter of 2006.

9 Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal and nuclear waste management on a present value basis consists of the following:

(millions of dollars)	**2005**	2004
Liability for nuclear used fuel management	**4,940**	4,693
Liability for nuclear decommissioning and low and intermediate level waste management	**3,627**	3,457
Liability for non-nuclear fixed asset removal	**192**	189
Fixed asset removal and nuclear waste management liability	**8,759**	8,339

The change in the fixed asset removal and nuclear waste management liability for the years ended December 31, 2005 and 2004, is as follows:

(millions of dollars)	**2005**	2004
Liability, beginning of year	**8,339**	7,921
Increase in liability due to accretion	**476**	453
Increase in liability due to nuclear used fuel and nuclear waste management variable expenses	**34**	35
Fixed asset removal of partnership interests	**–**	1
Liabilities settled by expenditures on waste management	**(90)**	(71)
Liability, end of year	**8,759**	8,339

OPG's asset retirement obligations are comprised of expected costs to be incurred up to and upon termination of operations and the closure of nuclear and fossil-fuelled generating plant facilities. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and fossil-fuelled production facilities at the end of their useful lives
- The present value of the fixed cost portion of any nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations
- The present value of the variable cost portion of any nuclear waste management program to take into account actual waste volumes incurred to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. Plant closures are projected to occur between one and 14 years from today, depending on the plant. Current plans include cash flow estimates to 2057 for decommissioning nuclear stations and to approximately 2100 for nuclear used fuel management. The undiscounted amount of estimated cash flows associated with the liability expected to be incurred up to and upon closure of generating stations is approximately $20 billion. The discount rate used to calculate the present value of the liabilities at December 31, 2005 was 5.75 per cent (2004 – 5.75 per cent) and the cost escalation rates ranged from two per cent to four per cent. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. The estimate of the liability is being updated in 2006. Changes to these assumptions, including changes to assumptions on the timing of the programs, financial indicators or the technology employed, could result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs
The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The current assumptions that have been used to establish the accrued used fuel costs include long-term management of the spent fuel bundles through deep geological disposal; an in-service date of 2035 for used nuclear fuel disposal facilities; and an average transportation distance of 1,000 kilometres between nuclear generating facilities and the disposal facilities. Alternatives to deep geological disposal have been studied by Canadian nuclear utilities via the Nuclear Waste Management Organization as part of the options study required by the federal Nuclear Fuel Waste Act (Canada) ("NFWA"). The options study was submitted to the federal government in November 2005. The federal government will decide which management alternative should be followed. The pending decision could have a significant impact on OPG's estimate of the liability.

Liability for Nuclear Decommissioning and Low and Intermediate Level Waste Management Costs
The liability for nuclear decommissioning and low and intermediate level waste management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis where the reactors will remain in a safe storage state for a 30-year period prior to a 10-year dismantlement period. Current plans assume that low and intermediate level waste arising during decommissioning will be disposed of at the facilities developed for disposal of operational low and intermediate level waste.

The life cycle costs of low and intermediate level waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term disposal of these wastes. The current assumptions used to establish the accrued low and intermediate level waste management costs include: an in-service date of 2015 for disposal facilities for low level waste; co-locating short-lived intermediate level waste with low level waste starting in 2015; and co-locating long-lived intermediate level waste with used fuel starting in 2035. Plans are currently proceeding for development of a deep geologic repository at the Western Waste Management Facility. Agreements are in place with the Municipality of Kincardine for this repository.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal is based on third-party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. This liability represents the estimated costs of decommissioning fossil-fuelled generating stations at the end of their service lives. The estimated retirement date of these stations is between 2007 and 2034.

In addition to the $95 million liability for active sites, OPG also has an asset retirement obligation liability of $97 million for decommissioning and restoration costs associated with plant sites that have been divested or are no longer in use.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities. Also, the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Ontario Nuclear Funds Agreement

OPG sets aside funds to be used specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In July 2003, OPG and the Province completed arrangements, pursuant to the ONFA. To comply with the ONFA, OPG established the Nuclear Funds. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund will be used to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. The initial funding of the Decommissioning Fund was intended to be sufficient to fully discharge the 1999 estimate of the liability. OPG bears the risk and liability for cost estimate increases and fund earnings in the Decommissioning Fund.

The Used Fuel Fund will be used to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability for cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $6 billion, a present value amount at April 1, 1999 (approximately $8.8 billion in 2005 dollars) based on used fuel bundle projections of 2.23 million bundles consistent with the station lives included within the initial financial reference plan. OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2005 under the ONFA was $454 million, including a contribution to The Ontario NFWA Trust (the "Trust"). In 2005, an amount of $150 million was directed to the Trust to meet the 2005 requirement of $100 million and $50 million was directed towards the 2006 requirement.

The NFWA was proclaimed into force in November 2002. In accordance with the NFWA, the Nuclear Waste Management Organization was formed to prepare and review alternatives, and to provide recommendations to the federal government for long-term management of nuclear fuel waste by November 2005. The federal government will select the option for dealing with the long-term management of nuclear fuel waste based on submitted plans. As required under the NFWA, OPG made an initial deposit of $500 million into the Trust in November 2002. The NFWA also requires OPG to make annual contributions of $100 million to the Trust, to be deposited into the Trust no later than the November anniversary of the NFWA. To comply with this requirement, OPG contributed $100 million to the Trust in each of 2003 and 2004 and $150 million in 2005 ($50 million funded on December 31, 2005 as part of OPG's $100 million funding requirement for the November 2005 to November 2006 period). Under the NFWA, OPG must continue to deposit $100 million annually into the Trust until the federal government has approved a long-term plan. Future contributions to the Trust beyond 2005 will be dependent on the direction chosen by the federal government based on the recommendations submitted in November 2005. Given that the Trust forms part of the Used Fuel Fund, contributions to the Trust, as required by the NFWA, are applied towards the ONFA payment obligations.

As required by the *Nuclear Safety and Control Act* (Canada), and under the terms of the ONFA, the Province issued a guarantee to the Canadian Nuclear Safety Commission ("CNSC"), on behalf of OPG, for up to $1,510 million. This is a guarantee that there will be sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The provincial guarantee will supplement the Used Fuel Fund and the Decommissioning Fund until they have accumulated sufficient funds to cover the accumulated liabilities for nuclear decommissioning and waste management. The guarantee, taken together with the Used Fuel Fund and Decommissioning Fund, was in satisfaction of OPG's nuclear licensing requirements with the CNSC. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount guaranteed by the Province. OPG paid the annual guarantee fee for 2005 of $8 million in the first quarter of 2005.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return"). The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of fund assets, which includes realized and unrealized returns, is due to or due from the Province. Since OPG accounts for the investments in the segregated funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At December 31, 2005, the Used Fuel Fund accounts included an amount due to the Province of $4 million (2004 – $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the consolidated financial statements, at December 31, 2005, there would be an amount due to the Province of $306 million (2004 – $156 million).

Under the ONFA, a rate of return target of 5.75 per cent per annum was established for the Decommissioning Fund, subject to changes in the ONFA Reference Plan. If the rate of return deviates from 5.75 per cent, or if the estimate of the liabilities changes under the current approved ONFA Reference Plan, the Decommissioning Fund may become over or underfunded. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the Current Approved ONFA Reference Plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent as a contribution to the Used Fuel Fund, and the OEFC is entitled to a distribution of an equal amount. In addition, upon termination of the ONFA, the Province has a right to any excess funds, which is the extent to which the fair market value of the Decommissioning Fund exceeds the estimated completion costs approved under the Current Approved ONFA Reference Plan. At December 31, 2005, the balance of the Decommissioning Fund, on an amortized cost basis, exceeded the estimated completion costs under the Current Approved ONFA Reference Plan. The Decommissioning Fund had an excess of $7 million due to the Province on an amortized cost basis. If the investments in the Decommissioning Fund were accounted for at fair market value in the consolidated financial statements at December 31, 2005, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $484 million (2004 – $249 million).

The nuclear fixed asset removal and nuclear waste management funds as at December 31, 2005 and 2004, consist of the following:

	Amortized Cost Basis		Fair Value	
(millions of dollars)	**2005**	2004	**2005**	2004
Decommissioning Fund	**4,106**	3,858	**4,583**	4,131
Due to Province – Decommissioning Fund	**(7)**	–	**(484)**	(249)
	4,099	3,858	**4,099**	3,882
Used Fuel Fund[1]	**2,693**	2,122	**2,995**	2,274
Due (to) from Province – Used Fuel Fund	**(4)**	(4)	**(306)**	(156)
	2,689	2,118	**2,689**	2,118
	6,788	5,976	**6,788**	6,000

1. The Ontario NFWA Trust represents $1,003 million as at December 31, 2005 (2004 – $794 million) of the Used Fuel Fund on an amortized cost basis.

The amortized cost and fair value of the securities invested in the segregated funds, which include the Used Fuel Fund and Decommissioning Fund, as at December 31, 2005 and 2004 are as follows:

	Amortized Cost Basis		Fair Value	
(millions of dollars)	**2005**	2004	**2005**	2004
Cash and cash equivalents and short-term investments	**516**	211	**515**	211
Marketable equity securities	**3,772**	3,056	**4,547**	3,472
Bonds and debentures	**1,757**	723	**1,762**	732
Receivable from the OEFC	**759**	1,993	**759**	1,993
Administrative expense payable	**(5)**	(3)	**(5)**	(3)
	6,799	5,980	**7,578**	6,405
Due to Province – Decommissioning Fund	**(7)**	–	**(484)**	(249)
Due to Province – Used Fuel Fund	**(4)**	(4)	**(306)**	(156)
Total	**6,788**	5,976	**6,788**	6,000

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31, 2005 and 2004 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2005**	2004
Less than 1 year	**–**	–
1 – 5 years	**769**	259
5 – 10 years	**485**	233
More than 10 years	**508**	240
Total maturities of debt securities	**1,762**	732
Average yield	**4.3%**	4.1%

The receivable of $759 million (2004 - $1,993 million) from the OEFC does not have a specified maturity date. The effective rate of interest on the OEFC receivable was 5.8 per cent in 2005 (2004 – 5.3 per cent).

10 Income taxes

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that the future income taxes are expected to be recovered in the regulated rates charged to future customers. As part of the transition, on April 1, 2005, OPG reversed the net future income tax asset balance of $74 million relating to the rate regulated segments of its business, and recognized the amount as an extraordinary loss in determining net income. The extraordinary item reduced basic and diluted earnings per share for the year ended December 31, 2005 by $0.29 per share.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2005**	2004
Income (loss) before income taxes	**558**	(38)
Combined Canadian federal and provincial statutory income tax rates, including surtax	**36.1%**	36.1%
Statutory income tax rates applied to accounting income	**202**	(14)
Increase (decrease) in income taxes resulting from:		
Large corporations tax in excess of surtax	**28**	30
Lower future tax rate on temporary differences	**(12)**	(3)
Non-taxable income items	**7**	(4)
Unrecorded future income tax related to regulated operations	**(157)**	–
Change in income tax positions	**50**	–
Change in future income tax asset valuation allowance	**–**	(93)
Other	**–**	4
	(84)	(66)
Income tax expense (recovery)	**118**	(80)
Effective rate of income taxes	**21.1%**	210.5%

Prior to 2004, OPG had established a valuation allowance of $93 million to recognize that it was more likely than not that this amount of future income taxes recoverable would not be realized in light of consecutive taxable losses in preceding years. In 2004, the valuation allowance was reduced by $93 million to nil as a consequence of the introduction of rate regulation. With the intended elimination of the future income tax assets and liabilities of the regulated business upon inception of rate regulation on April 1, 2005, it was expected that there would be a significant future income tax liability position remaining in the unregulated business. This expected future income tax liability position enabled OPG to recognize, in 2004, the $93 million in future income tax assets. This resulted in a reduction in the 2004 income tax provision which did not occur in 2005.

OPG has taken certain filing positions for corporate income and capital taxes that may be challenged on audit and possibly disallowed and result in a significant increase in the tax obligation upon reassessment. During 2005, OPG recorded an income tax charge of $50 million to provide for a change in income tax liabilities related to certain income tax positions that the Company has taken in prior years. There is still uncertainty around the amount of the tax provision, and Management is not able to determine the impact of that uncertainty on the consolidated financial statements.

Significant components of the provision for income tax expense (recovery) are presented in the table below:

(millions of dollars)	**2005**	2004
Current income tax expense	**80**	21
Future income tax expense (benefits):		
Change in temporary differences	**(51)**	50
Non-capital loss carry-forward	**88**	(67)
Valuation allowance (reversal)	**–**	(93)
Other	**1**	9
	38	(101)
Income tax expense (recovery)	**118**	(80)

The income tax effects of temporary differences that give rise to future income tax assets and liabilities are presented in the table below:

(millions of dollars)	**2005**	2004
Future income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**27**	2,806
Other liabilities and assets	**107**	446
Non-capital loss carry-forward	**98**	168
Future recoverable Ontario minimum tax	**37**	42
	269	3,462
Future income tax liabilities:		
Fixed assets	**351**	1,211
Fixed asset removal and nuclear waste management fund	**–**	2,039
Other liabilities and assets	**141**	323
	492	3,573
Net future income tax liabilities	**223**	111
Represented by:		
Current portion (asset)	**(18)**	(44)
Long-term portion	**241**	155
	223	111

The following table summarizes the consolidated statement of income and balance sheet amounts under the method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business for 2005:

(millions of dollars)	As Stated	Liability Method
Future income tax expense	**38**	195
Extraordinary item	**74**	–
Current portion (assets)	**(18)**	(38)
Long-term portion	**241**	344

Had OPG continued to use the liability method of accounting for income taxes for the regulated business, the future tax expense for the year ended December 31, 2005 would have increased by $157 million with a corresponding increase in the future income tax liability.

At December 31, 2005, OPG had available approximately $280 million (2004 – $549 million) of non-capital loss carry-forwards. The non-capital loss carry-forward is related to the following taxation years:

(millions of dollars)	Loss-Carry Forward	Expiry Date
2003	33	2010
2004	247	2014

The amount of cash income taxes paid during 2005 was $20 million (2004 – $17 million).

11 Benefit Plans

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. The registered pension plan is a contributory defined benefit plan covering most employees and retirees. Pension fund assets include equity securities and corporate and government debt securities, real estate and other investments which are managed by professional investment managers. The fund does not invest in equity or debt securities issued by OPG. The supplementary pension plans are defined benefit plans covering certain employees and retirees.

Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The pension and OPEB obligations, and the pension fund assets, are measured at December 31, 2005.

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2005	2004	**2005**	2004
Weighted Average Assumptions – Benefit Obligation at Year End				
Rate used to discount future benefits	**5.00%**	6.00%	**4.97%**	5.88%
Salary schedule escalation rate	**3.00%**	3.25%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.25%	**–**	–
Initial health care trend rate	**–**	–	**7.76%**	7.03%
Ultimate health care trend rate	**–**	–	**4.68%**	4.46%
Year ultimate rate reached	**–**	–	**2014**	2014
Rate of increase in disability benefits	**–**	–	**2.00%**	2.25%

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2005	2004	**2005**	2004
Weighted Average Assumptions – Cost for the Year				
Expected return on plan assets net of expenses	**7.00%**	7.00%	**–**	–
Rate used to discount future benefits	**6.00%**	6.25%	**5.88%**	6.17%
Salary schedule escalation rate	**3.25%**	3.25%	**–**	–
Rate of cost of living increase to pensions	**2.25%**	2.25%	**–**	–
Initial health care trend rate	**–**	–	**7.03%**	6.33%
Ultimate health care trend rate	**–**	–	**4.46%**	4.46%
Year ultimate rate reached	**–**	–	**2014**	2010
Rate of increase in disability benefits	**–**	–	**2.25%**	2.25%
Average remaining service life for employees (years)	**11**	12	**11**	12

(millions of dollars)	Registered Pension Plan 2005	Registered Pension Plan 2004	Supplementary Pension Plans 2005	Supplementary Pension Plans 2004	Other Post Employment Benefits 2005	Other Post Employment Benefits 2004
Changes in Plan Assets						
Fair value of plan assets at beginning of year	**7,056**	6,449	**–**	–	**–**	–
Contributions by employer	**254**	154	**7**	6	**58**	54
Contributions by employees	**56**	52	**–**	–	**–**	–
Actual return on plan assets net of expenses	**858**	693	**–**	–	**–**	–
Settlements	**(2)**	(4)	**–**	–	**–**	–
Benefit payments	**(301)**	(288)	**(7)**	(6)	**(58)**	(54)
Fair value of plan assets at end of year	**7,921**	7,056	**–**	–	**–**	–
Changes in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	**7,663**	7,046	**144**	117	**1,499**	1,307
Employer current service costs	**163**	143	**7**	8	**47**	41
Contributions by employees	**56**	52	**–**	–	**–**	–
Interest on projected benefit obligation	**461**	442	**9**	7	**88**	82
Past service costs	**–**	–	**–**	–	**1**	–
Curtailment loss (gain)	**–**	2	**–**	–	**–**	(1)
Settlement gain	**(2)**	(4)	**–**	–	**–**	–
Benefit payments	**(301)**	(288)	**(7)**	(6)	**(58)**	(54)
Net actuarial loss (gain)	**1,055**	270	**(9)**	18	**488**	124
Projected benefit obligation at end of year	**9,095**	7,663	**144**	144	**2,065**	1,499
Funded Status – Deficit at end of year	**(1,174)**	(607)	**(144)**	(144)	**(2,065)**	(1,499)

	2005	2004
Registered pension plan fund asset investment categories		
Equities	**64%**	65%
Fixed income	**33%**	33%
Cash and short-term	**3%**	2%
Total	**100%**	100%

The assets of the OPG pension fund are allocated among three principal investment categories. Furthermore, equity investments are diversified across Canadian, U.S. and non-North American stocks. The fund also has a small real estate portfolio that is less than one per cent of plan assets.

Based on the most recently filed actuarial valuation, as at January 1, 2005, there was an unfunded liability on a going-concern basis of $465 million and a deficiency on a wind-up basis of $1,979 million. In the previously filed actuarial valuation, as at April 1, 2002, there was a surplus of $262 million on a going-concern basis and $204 million on a wind-up basis.

The supplementary plans are not funded, but are secured by letters of credit totalling $138 million (2004 – $125 million).

(millions of dollars)	Registered Pension Plan 2005	Registered Pension Plan 2004	Supplementary Pension Plans 2005	Supplementary Pension Plans 2004	Other Post Employment Benefits 2005	Other Post Employment Benefits 2004
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)						
Funded status – deficit at end of year	**(1,174)**	(607)	**(144)**	(144)	**(2,065)**	(1,499)
Unamortized net actuarial loss	**1,737**	1,012	**18**	28	**885**	422
Unamortized past service costs	**100**	119	**4**	5	**16**	18
Accrued benefit asset (liability) at end of year	**663**	524	**(122)**	(111)	**(1,164)**	(1,059)
Short-term portion	**–**	–	**(7)**	(6)	**(67)**	(59)
Long-term portion	**663**	524	**(115)**	(105)	**(1,097)**	(1,000)

(millions of dollars)	Registered Pension Plan 2005	Registered Pension Plan 2004	Supplementary Pension Plans 2005	Supplementary Pension Plans 2004	Other Post Employment Benefits 2005	Other Post Employment Benefits 2004
Components of Cost Recognized						
Current service costs	**163**	143	**7**	8	**47**	41
Interest on projected benefit obligation	**461**	442	**9**	7	**88**	82
Expected return on plan assets net of expenses	**(527)**	(511)	**–**	–	**–**	–
Curtailment loss (gain)	**–**	2	**–**	–	**–**	(1)
Amortization of past service costs	**18**	18	**1**	1	**3**	3
Amortization of net actuarial loss	**–**	–	**1**	–	**25**	15
Cost recognized	**115**	94	**18**	16	**163**	140

(millions of dollars)	Registered Pension Plan 2005	Registered Pension Plan 2004	Supplementary Pension Plans 2005	Supplementary Pension Plans 2004	Other Post Employment Benefits 2005	Other Post Employment Benefits 2004
Components of Cost Incurred and Recognized						
Current service costs	**163**	143	**7**	8	**47**	41
Interest on projected benefit obligation	**461**	442	**9**	7	**88**	82
Actual return on plan assets net of expenses	**(858)**	(693)	**–**	–	**–**	–
Curtailment loss (gain)	**–**	2	**–**	–	**–**	(1)
Past service costs	**–**	–	**–**	–	**1**	–
Net actuarial loss (gain)	**1,055**	270	**(9)**	18	**488**	124
Cost incurred in year	**821**	164	**7**	33	**624**	246
Differences between costs incurred and recognized in respect of:						
Actual return on plan assets net of expenses	**331**	182	**–**	–	**–**	–
Past service costs	**18**	18	**1**	1	**2**	3
Net actuarial (gain) loss	**(1,055)**	(270)	**10**	(18)	**(463)**	(109)
Cost recognized	**115**	94	**18**	16	**163**	140

A one per cent increase or decrease in the health care trend rate would result in an increase in the service and interest components of the 2005 OPEB cost recognized of $26 million (2004 – $21 million) or a decrease in the service and interest components of the 2005 OPEB cost recognized of $20 million (2004 – $19 million), respectively. A one per cent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2005 of $343 million (2004 – $221 million) or a decrease in the projected OPEB obligation at December 31, 2005 of $266 million (2004 – $175 million).

12 Financial Instruments

Fair values of derivative instruments have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG considers various factors to estimate forward prices, including market prices and price volatility in neighbouring electricity markets, market prices for fuel, and other factors.

Trading activities and liquidity in the Ontario electricity market have been limited as companies are generally entering only into short-term contracts. As a result, forward pricing information for contracts may not accurately represent the cost to enter into these contracts. For Ontario-based contracts that are not entered into for hedging purposes, OPG established liquidity reserves against the fair market value of the assets and liabilities equal to the gain or loss on these contracts. These reserves increased trading revenue by $4 million during 2005 (2004 – decreased by $2 million). Contracts for transactions outside of Ontario continue to be carried on the consolidated balance sheets as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

Derivative Instruments Used for Hedging Purposes

The following table provides the estimated fair value of derivative instruments designated as hedges. The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

(millions of dollars except where noted)	**Notional Quantity**	**Terms 2005**	**Fair Value**	Notional Quantity	Terms 2004	Fair Value
(Loss)						
Electricity derivative instruments	**4.1 TWh**	**1–2 yrs**	**(125)**	10.4 TWh	1–3 yrs	(71)
Foreign exchange derivative instruments	**U.S. $15**	**Jan/06**	**–**	U.S. $10	Jan/05	–
Interest rate hedges	**400**	**1–15 yrs**	**(7)**	–	–	–

OPG entered into a number of forward start interest rate swap agreements to hedge against the effect of future interest rate movement based on the anticipated future borrowing requirement for the Niagara tunnel project. These transactions are ordinarily accounted for as hedges, however, approximately $5 million was charged to current period operations for those hedges that did not meet the effectiveness criteria during 2005. The remaining loss was deferred.

Foreign exchange derivative instruments are used to hedge the exposure to anticipated U.S. dollar denominated purchases. The weighted average fixed exchange rate for contracts outstanding at December 31, 2005 was U.S. $0.87 (2004 – U.S. $0.81) for every Canadian dollar.

Derivative Instruments Not Used for Hedging Purposes

The carrying amount (fair value) of derivative instruments not designated for hedging purposes is as follows:

(millions of dollars except where noted)	**Notional Quantity 2005**	**Fair Value 2005**	Notional Quantity 2004	Fair Value 2004
Foreign exchange derivative	**U.S. $3**	**–**	–	–
Commodity derivative instruments				
Assets	**3.3 TWh**	**13**	7.9 TWh	12
Liabilities	**1.1 TWh**	**(37)**	1.3 TWh	(12)
		(24)		–
Ontario market liquidity reserve		**(3)**		(7)
Total		**(27)**		(7)

Foreign exchange derivative instruments that are not designated as hedges have a weighted average exchange rate of U.S. $0.85.

Fair Value of Other Financial Instruments

The carrying values of cash and cash equivalents, accounts receivable, accounts payable and accrued charges, Market Power Mitigation Agreement rebate payable, short-term notes payable, and long-term debt due within one year approximate their fair values due to the immediate or short-term maturity of these financial instruments. Fair values for other financial instruments have been estimated by reference to quoted market prices for actual or similar instruments where available.

The carrying values and fair values of these other financial instruments are as follows:

(millions of dollars)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
	2005		2004	
Financial Assets				
Nuclear fixed asset removal and nuclear waste management funds	**6,788**	**6,788**	5,976	6,000
Long-term accounts receivable and other assets	**61**	**61**	56	56
Financial Liabilities				
Long-term debt	**3,895**	**4,081**	3,404	3,582
Long-term accounts payable and accrued charges	**183**	**183**	212	212

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. OPG derives revenue from several other sources including the sale of energy products and financial risk management products to third parties. However, the majority of OPG revenues are derived from sales through the IESO administered spot market.

Credit exposure to the IESO fluctuates based on spot prices and the volume of rate regulated and unregulated generation, and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at $1,146 million during the year ended December 31, 2005 and at $901 million during the year ended December 31, 2004.

13 Common Shares

As at December 31, 2005 and 2004, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value.

14 Commitments and Contingencies

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities. OPG had become aware of a class action suit for $50 billion, relating to alleged negative health impacts caused by burning coal to generate electricity, that has been issued in an Ontario Court naming OPG and 20 U.S.-based electricity generators as defendants. Although the claim was filed in the court office, it has not been served on OPG and, the time allowed to the plaintiff to serve the claim has expired. While the court has discretion to extend the time for service upon a motion by the Plaintiffs, OPG does not believe this is likely. The preliminary assessment is that the claim would be unlikely to succeed even if the Plaintiffs further pursued the claim.

In July 2004, OPG and two individual OPG employees were each charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 drowning accident at Barrett Chute. The trial commenced on January 16, 2006, and is expected to last approximately four to six months.

Also, certain First Nations have commenced actions for interference with reserve and traditional land rights. The claims by some of these First Nations total approximately $50 million and claims by others are for unspecified amounts.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG and could have a significant effect on OPG's financial position. Management has provided for contingencies that are determined to be likely and are responsibly measurable.

Environmental

OPG was required to assume certain environmental obligations from Ontario Hydro. A provision of $76 million was established as at April 1, 1999 for such obligations. During the year ended December 31, 2005, expenditures of $4 million (2004 – $2 million) were recorded against the provision.

Current operations are subject to regulation with respect to air, soil and water quality and other environmental matters by federal, provincial and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its consolidated financial statements to meet OPG's current environmental obligations.

Guarantees

As part of normal business, OPG and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, standby Letters of Credit and surety bonds.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2005 are as follows:

(millions of dollars)	2006	2007	2008	2009	2010	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	693	425	197	68	15	15	1,413
Contributions under ONFA	454	454	679	350	350	1,403	3,690
Long-term debt repayment	800	400	400	350	970	775	3,695
Interest on long-term debt	214	168	145	122	90	55	794
Unconditional purchase obligations	26	20	12	9	15	27	109
Long-term accounts payable	28	28	9	–	–	–	65
Operating lease obligations	13	13	13	13	14	–	66
Pension contributions[1]	254	–	–	–	–	–	254
Other	75	34	35	34	35	11	224
Significant commercial commitments:							
Niagara Tunnel	158	173	172	116	1	–	620
Total	2,715	1,715	1,662	1,062	1,490	2,286	10,930

1. The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuation as at January 1, 2005. The contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, and the timing of funding valuations. Funding requirements after 2006 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

In June 2004, OPG announced and the Government of Ontario ("Government") endorsed the decision to proceed with a new water diversion tunnel that will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara. This tunnel will allow the Beck generating facilities to utilize available water more effectively, and is expected to increase annual generation on average by about 1.6 TWh. OPG awarded a contract to Strabag AG in August 2005 to design and construct the 10.4 kilometre tunnel and associated facilities. The value of the design-build contract is approximately $600 million, with the total project expected to cost approximately $985 million. Construction started in September 2005. Project completion is expected by late 2009.

Other Commitments

In addition to the above commitments, the Company has the following commitments:

The Company maintains labour agreements with the Power Workers' Union ("PWU"). The agreement is effective from April 1, 2002 to March 31, 2006. OPG and the PWU recently reached tentative agreements, which are subject to membership ratification. The Company also maintains a labour agreement with the Society of Energy Professionals. The agreement is effective from January 1, 2005 to December 31, 2005. The agreement has since been renewed and extended to December 31, 2010. As of December 31, 2005, the Company had approximately 90 per cent of its regular labour forces covered by collective bargaining agreements.

Contractual and commercial commitments above exclude certain purchase orders as they represent purchase authorizations rather than legally binding contracts and are subject to change without significant penalties.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. Updates to the regulation may not occur for up to two years. OPG has not recorded any amounts relating to this anticipated regulation change.

15 Restructuring

The change in the restructuring liability for termination benefits for 2005 and 2004 is as follows:

(millions of dollars)	**2005**	2004
Liability, beginning of year	**20**	52
Restructuring charges	**10**	19
Payments	**(18)**	(51)
Liability, end of year	**12**	20

During 2004, OPG recorded restructuring charges of $16 million, which consisted of $15 million for termination benefits and $1 million in related pension and OPEB expenses associated with its Lakeview generating station. OPG also recorded restructuring charges of $4 million related to its Energy Marketing business during 2004. During 2005, OPG recorded restructuring charges of $10 million which consisted of $4 million related to the Lakeview generating station and $6 million related to the Energy Markets business.

16 Transition Rate Option Contracts

Under regulation known as Transition – Generation Corporation Designated Rate Options ("TRO"), OPG has been required to provide transitional price relief since market opening to certain power customers for up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The TRO is treated as a hedge of generation revenue. The maximum anticipated volume subject to the transitional price relief was approximately 5.4 TWh in the first year after market opening and 3.6 TWh in the second year. The maximum anticipated volume in each of the third and fourth years is 1.8 TWh. The maximum length of the program is four years, which expires April 30, 2006.

A provision of $210 million on the TRO contracts was recorded in the first quarter of 2002 based on the estimated future loss on these contracts. The provision was determined at that time using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on these contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates. The provision for the TRO contracts was established based on meeting decontrol targets within three years of market opening. An additional charge of $30 million related to the fourth year of the TRO contracts was recorded in 2003, based on OPG's expectation that the Company would not meet the decontrol targets necessary for TRO contracts to expire after three years.

The change in the TRO contracts provision for the years ended December 31, 2005 and 2004 is as follows:

(millions of dollars)	**2005**	2004
Provision, beginning of year	**48**	100
Decrease of provision during the year	**(36)**	(52)
Provision, end of year	**12**	48

17 Market Power Mitigation Agreement Rebate

Until April 1, 2005, OPG was required under its generating licence to comply with prescribed market power mitigation measures to address the potential for OPG to exercise market power in Ontario. The market power mitigation measures included both a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, a majority of OPG's expected energy sales in Ontario were subject to an average annual revenue cap of 3.8¢/kWh. During the term of the Market Power Mitigation Agreement, OPG was required to pay a rebate to the Independent Electricity System Operator equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a 12-month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The Market Power Mitigation Agreement was replaced effective April 1, 2005 by a regulated price for baseload hydroelectric and nuclear generation and a revenue limit that applies to OPG's unregulated generation assets.

In accordance with the Market Power Mitigation Agreement, the rebate was calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the three months ended March 31, 2005, when the rebate mechanism ended, exceeded the 3.8¢/kWh revenue cap, OPG provided $412 million (2004 – $1,154 million) as a Market Power Mitigation Agreement rebate.

The change in the Market Power Mitigation Agreement rebate liability for the years ended December 31, 2005 and 2004 is as follows:

(millions of dollars)	**2005**	2004
Liability, beginning of year	**439**	409
Increase to provision during the year	**412**	1,154
Payments	**(851)**	(1,124)
Liability, end of year	**–**	439

18 Revenue Limit Rebate

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, is subject to a revenue limit based on an average price of $47.00/MWh (4.7¢/kWh). This revenue limit was originally established for a period of 13 months ending April 30, 2006. The Government has recently announced the extension of the revenue limit for an additional three years. Starting May 1, 2006, the revenue limit will decrease to 4.6¢/kWh from the present limit of 4.7¢/kWh. On April 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective April 1, 2008. Revenues above these limits will be returned to the Independent Electricity System Operator ("IESO"), and the IESO will subsequently issue a rebate to consumers.

The change in the revenue limit rebate liability for the year ended December 31, 2005 is as follows:

(millions of dollars)	**2005**
Liability, beginning of year	**–**
Increase to provision during the year	**739**
Payments	**–**
Liability, end of year	**739**

19 Business Segments

A regulation made pursuant to the Electricity Restructuring Act, 2004 provided that OPG would receive regulated prices for its baseload hydroelectric and nuclear facilities. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the OEB will have established new regulated prices. Given the effective date of these prices, and OPG's management approach, OPG changed its definition of business segments on April 1, 2005 from Generation and Energy Marketing to Regulated – Nuclear, Regulated – Hydroelectric and Unregulated Generation. OPG will continue to report other activities, including the previously separately presented trading activities in the Other category. As a result of this change in definition, OPG has reclassified the comparative periods to be consistent with the current presentation of business segments.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations.

OPG's Regulated – Nuclear business segment includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. The arrangement includes lease revenue, interest income and revenue from engineering analysis and design, technical and other services. The Regulated – Nuclear business segment also includes revenue earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support. These earnings are included in the Regulated – Nuclear business segment since they were included in determining the regulated price for production from the nuclear facilities.

Bruce Nuclear Generating Stations

In May 2001, the Company leased its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with options to renew for up to 25 years.

Under the terms of the lease, OPG agreed to transfer certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. Pension assets and liabilities related to the approximately 3,000 employees were transferred to Bruce Power. Bruce Power assumed the liability for other post employment benefits for these employees. OPG makes payments to Bruce Power in respect of other post employment benefits of approximately $2.3 million per month over a 72-month period, ending in 2008.

As part of the closing, OPG recorded deferred revenue to reflect the initial payments of $595 million less net assets transferred to Bruce Power under the lease agreement. The deferred revenue is being amortized over the initial lease term of approximately 18 years and is recorded as revenue.

In December 2002, British Energy plc, entered into an agreement to dispose of its entire 82.4 per cent interest in Bruce Power. The transaction was completed in February 2003 and a consortium of Canadian companies assumed the lease of the Bruce A and Bruce B nuclear generating stations that was formerly held by British Energy plc. The Bruce facilities will continue to be operated by Bruce Power. Upon closing of the transaction, the $225 million note receivable was paid to OPG, and lease payments commenced to be paid monthly. Proceeds from the note are to be applied by March 2008 against OPG's funding requirements with respect to the nuclear fixed asset removal and nuclear waste management liabilities.

As part of the agreement reached in October 2005 between the Province and Bruce Power, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to accept certain amendments to the lease agreement. These amendments included a change to the provisions regarding the transfer of Bruce Power's interest in the site and included a reduction of the annual lease payment for three of the four refurbished Bruce A units to $5.5 million per unit (in 2002 dollars, escalated at CPI), after the planned future refurbishments are completed. These changes to the lease agreement will impact OPG when Units 1 and 2 of the Bruce A nuclear generating station are returned to service, and when Unit 3 is refurbished at the end of its current operational life. Other changes to the existing arrangements were made to address Cameco Corporation's decision not to participate in the refurbishment of the Bruce A nuclear generating station.

For 2004 through 2008, minimum payments under the lease are $190 million annually, subject to limited exceptions. The lease revenue of $244 million (2004 – $236 million) was recorded in revenue. The remaining terms of the operating lease agreement will remain substantially unchanged until the planned future refurbishments are completed.

The net book value of fixed assets on lease to Bruce power including costs relating to refurbishing and restarting Bruce A at December 31, 2005, was $492 million (2004 – $590 million).

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its baseload hydroelectric generating stations. The business segment includes electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated Generation Segment

OPG's Unregulated Generation business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations and from the hydroelectric generating stations not included in the Regulated – Hydroelectric segment. The Unregulated Generation business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Other

OPG earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

Segment Income for year ended December 31, 2005	**Regulated – Nuclear**	**Regulated – Hydroelectric**	**Unregulated Generation**	**Other**	**Total**
(millions of dollars)					
Revenues					
Revenue	**2,607**	**857**	**3,399**	**86**	**6,949**
Market Power Mitigation Agreement rebate	**(160)**	**(65)**	**(187)**	**–**	**(412)**
Revenue limit rebate	**–**	**–**	**(739)**	**–**	**(739)**
	2,447	**792**	**2,473**	**86**	**5,798**
Fuel expense	**115**	**254**	**928**	**–**	**1,297**
Gross margin	**2,332**	**538**	**1,545**	**86**	**4,501**
Operations, maintenance and administration	**1,788**	**77**	**594**	**57**	**2,516**
Depreciation and amortization	**374**	**68**	**276**	**35**	**753**
Accretion on fixed asset removal and nuclear waste management liabilities	**467**	**–**	**9**	**–**	**476**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(381)**	**–**	**–**	**–**	**(381)**
Property and capital taxes	**31**	**18**	**54**	**4**	**107**
Restructuring	**–**	**–**	**4**	**6**	**10**
Income (loss) before the following:	**53**	**375**	**608**	**(16)**	**1,020**
Impairment of long-lived assets	**63**	**–**	**202**	**–**	**265**
(Loss) income before interest, income taxes and extraordinary item	**(10)**	**375**	**406**	**(16)**	**755**

Segment Income for year ended December 31, 2004	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
(millions of dollars)					
Revenues					
Revenue	2,421	1,018	2,528	105	6,072
Market Power Mitigation Agreement rebate	(374)	(194)	(586)	–	(1,154)
Revenue limit rebate	–	–	–	–	–
	2,047	824	1,942	105	4,918
Fuel expense	108	255	790	–	1,153
Gross margin	1,939	569	1,152	105	3,765
Operations, maintenance and administration excluding Pickering A return to service	1,611	74	576	62	2,323
Pickering A return to service	271	–	–	–	271
Depreciation and amortization	360	71	302	32	765
Accretion on fixed asset removal and nuclear waste management liabilities	445	–	8	–	453
Earnings on nuclear fixed asset removal and nuclear waste management funds	(313)	–	–	–	(313)
Property and capital taxes	33	18	38	14	103
Restructuring	–	–	16	4	20
Other income	–	–	–	(8)	(8)
(Loss) income before interest, and income taxes	(468)	406	212	1	151

(millions of dollars)	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
Selected Balance Sheet Information					
December 31, 2005					
Segment property, plant and equipment, net	**3,156**	**4,054**	**3,607**	**595**	**11,412**
December 31, 2004					
Segment property, plant and equipment, net	3,305	4,015	3,986	634	11,940
Selected Cash Flow Information					
Year ended December 31, 2005					
Capital expenditures	**273**	**101**	**90**	**34**	**498**
Year ended December 31, 2004					
Capital expenditures	365	25	78	93	561

20 Related Party Transactions

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

(millions of dollars)	**Revenues 2005**	**Expenses 2005**	Revenues 2004	Expenses 2004
Hydro One				
Electricity sales	**40**	**–**	40	–
Services	**–**	**12**	–	12
Settlement Transactions	**–**	**27**	–	33
Province of Ontario				
GRC water rentals and land tax	**–**	**132**	–	152
Guarantee fee	**–**	**8**	–	8
Used Fuel Fund rate of return guarantee	**–**	**–**	–	14
Decommissioning Fund excess funding	**–**	**7**	–	–
Other	**–**	**–**	–	2
OEFC				
GRC and proxy property tax	**–**	**207**	–	214
Interest income on receivable	**–**	**(75)**	–	(101)
Interest expense on long-term notes	**–**	**211**	–	191
Capital tax	**–**	**51**	–	49
Income taxes	**–**	**192**	–	(80)
Indemnity fees	**–**	**5**	–	5
IESO				
Electricity sales	**6,517**	**329**	5,465	304
Market Power Mitigation Agreement rebate	**(412)**	**–**	(1,154)	–
Revenue limit rebate	**(739)**	**–**	–	–
Ancillary services	**68**	**–**	90	–
Other	**–**	**–**	1	1
	5,474	**1,106**	4,442	804

At December 31, 2005, accounts receivable included $14 million (2004 – $14 million) due from Hydro One and $324 million (2004 – $158 million) due from the IESO. Accounts payable and accrued charges at December 31, 2005 included $2 million (2004 – $3 million) due to Hydro One.

21 Joint ventures

Significant joint ventures include Brighton Beach Power L.P., which is 50 per cent owned by OPG (2004 – 50 per cent).

The following condensed information from the consolidated statements of operations, cash flows and balance sheets detail the Company's share of its investment in joint ventures and partnerships that have been proportionately consolidated:

(millions of dollars)	**2005**	2004
Proportionate joint venture operations		
Operating revenue	**46**	28
Operating expenses	**(36)**	(22)
Net income	**10**	6
Proportionate joint venture cash flows		
Operating activities	**21**	4
Investing activities	**(2)**	(34)
Financing activities	**(4)**	32
Share of increase in cash	**15**	2
Proportionate joint venture balance sheets		
Current assets	**26**	16
Long-term assets	**279**	286
Current liabilities	**(11)**	(5)
Long-term liabilities	**(199)**	(202)
Share of net assets	**95**	95

22 Investment Company

The Company applied AcG-18 for all investments owned by OPGV in 2005. OPGV is a wholly owned subsidiary of the Company and its results are consolidated into the Company's financial statements. Since OPGV is the only enterprise in the group that satisfies the criteria set out in AcG-18, all other investments made by OPG and its subsidiaries, partnerships or joint ventures continue to be carried at amortized cost. The carrying amount of OPGV's investments was $29 million (2004 – $36 million) and the amount was included as long-term accounts receivable and other assets on the consolidated balance sheets.

As a result of the application of this policy, the Company's net income for 2005 decreased by $11 million and other assets decreased by the same amount. The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2005 were $2 million and $13 million respectively.

23 Research and Development

For the year ended December 31, 2005, $19 million (2004 – $21 million) of research and development expenses were charged to operations.

24 Other Income

There was no other income recorded in 2005. Other income of $8 million in 2004 was comprised of $3 million from the sale of assets and $5 million from a favourable pension liability settlement.

25 Changes in Non-Cash Working Capital Balances

(millions of dollars)	**2005**	2004
Accounts receivable	**(191)**	(15)
Income taxes recoverable	**–**	16
Fuel inventory	**(12)**	(45)
Materials and supplies	**(23)**	(19)
Market Power Mitigation Agreement rebate payable	**(439)**	30
Revenue limit rebate payable	**739**	–
Accounts payable and accrued charges	**10**	(78)
Income and capital taxes payable	**69**	12
	153	(99)

Board of Directors*

Jake Epp

Chairman

Jim Hankinson

President and CEO

Donald Hintz

Retired President,
Entergy Corporation

Gary Kugler

Corporate Director

M. George Lewis

Chairman and CEO,
RBC Asset
Management Inc.

David J. MacMillan

Corporate Director

Corbin A. McNeill Jr.

Retired Chairman and
Co-Chief Executive Officer,
Exelon Corporation

Peggy Mulligan

Executive Vice
President and Chief
Financial Officer,
Linamar Corporation

C. Ian Ross

Chairman,
GrowthWorks Canadian
Fund Ltd.

Marie C. Rounding

Counsel,
Gowling Lafleur
Henderson LLP

William (Bill) Sheffield

Corporate Director

David G. Unruh

Corporate Director

*Titles of Board directors are current as of May 2006

Officers*

Jake Epp

Chairman

Jim Hankinson

President and CEO

Bruce Boland

Senior Vice President, Corporate Affairs

Jim Burpee

Executive Vice President, Corporate Development

Pierre Charlebois

Executive Vice President and Chief Nuclear Officer

Cara Clairman

Acting Vice President, Law and General Counsel; Acting Vice President, Sustainable Development

Janice Dunlop

Senior Vice President, Human Resources and Chief Ethics Officer

Donn Hanbidge

Senior Vice President and Chief Financial Officer

Catriona King

Vice President, Corporate Secretary

John Murphy

Executive Vice President, Hydro

Colleen Sidford

Vice President, Treasurer

Jim Twomey

Executive Vice President, Fossil

*Titles of officers are current as of May 2006

Ontario Power Generation Facilities

3 nuclear stations

5 fossil-fuelled stations

64 hydroelectric stations

3 wind power stations (includes OPG's 50% interest in the Huron Wind joint venture)

This annual report is also available in French on our Web site –
ce rapport est également publié en français – at **www.opg.com**

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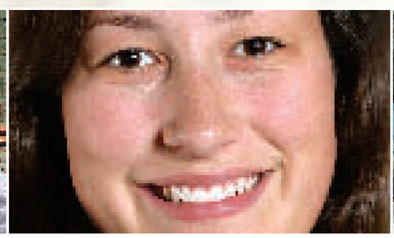
The head office of Ontario Power Generation Inc. is located at
700 University Avenue, Toronto, Ontario M5G 1X6;
telephone (416) 592-2555 or (877) 592-2555.

ONTARIO POWER GENERATION

2006 ANNUAL REPORT

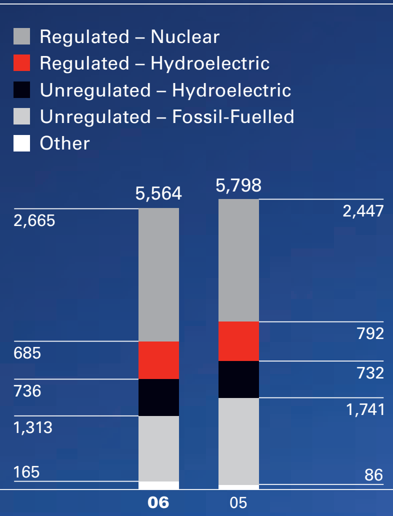
It's All About Performance



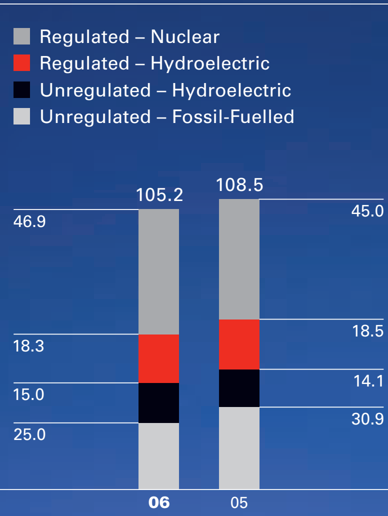



ONTARIO POWER GENERATION

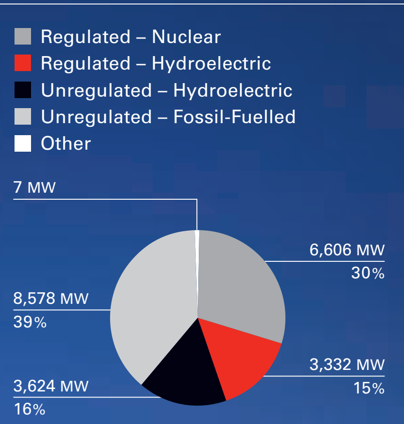
Revenue, Net of Revenue Limit and Market Power Mitigation Agreement Rebates
(millions of dollars)



Electricity Production
(TWh)



In-Service Generating Capacity
December 31, 2006
22,147 MW



Financial Highlights

Years Ended December 31 (millions of dollars)	**2006**	2005
Earnings		
Revenue after revenue limit and Market Power Mitigation Agreement rebates	**5,564**	5,798
Fuel expense	**1,098**	1,297
Gross margin	**4,466**	4,501
Operations, maintenance and administration	**2,777**	2,516
Other expenses	**1,091**	1,162
Impairment of long-lived assets	**22**	265
Income tax expense	**86**	118
Extraordinary item	**–**	74
Net income	**490**	366
Cash flow		
Cash flow provided by operating activities	**397**	1,201

Corporate Profile

Select List of Accomplishments

OPG's Darlington and Nanticoke stations are Ontario's top electricity producers during the mid-summer heat wave.

OPG launches a Federal Environmental Assessment on the potential refurbishment of its Pickering B nuclear station.

Niagara Tunnel excavation starts.

OPG's fossil-fuelled stations achieve their lowest recorded acid gas emissions and emission rates.

OPG files an application for a Site Preparation Licence for new nuclear generating units at its Darlington nuclear generating site.

Construction begins on the 550 MW Portlands Energy Centre in downtown Toronto.

Ontario Power Generation is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

In 2006, OPG generated 105.2 terawatt hours (TWh) of electricity.

OPG's electricity generating portfolio as of December 31, 2006, had a total in-service capacity of 22,147 megawatts (MW), which consisted of:

- three nuclear generating stations with a capacity of 6,606 MW
- five fossil-fuelled generating stations with a capacity of 8,578 MW
- 64 hydroelectric generating stations with a capacity of 6,956 MW, and
- three wind generating stations (which includes a 50% interest in the Huron Wind joint venture) with a capacity of 7 MW.

In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach gas-fired generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P.

Electricity Terms

One megawatt (MW) is one million watts. Megawatts are a measure of electricity supply capacity at a point in time.

One kilowatt (kW) is 1,000 watts; one gigawatt (GW) is one billion watts; and one terawatt (TW) is one trillion watts.

One kilowatt hour (kWh) is a measure of electricity demand per hour by customers. One kilowatt hour is the energy expended by ten 100 watt lights burning for one hour.

The average Ontario household uses approximately 1,000 kWh per month.

One megawatt hour (MWh) is 1,000 kWh; one gigawatt hour (GWh) is one million kWh; and one terawatt hour (TWh) is one billion kWh.

Contents

"Throughout 2006, OPG continued to demonstrate to our Shareholder our ability to improve performance and deliver on our commitments."

JAKE EPP
Chairman

Chairman's Message

OPG's Board of Directors continued its focus in 2006 on supporting and advising management to ensure accountability for the sound and successful operation of the Company. The Board also focused on continuing to improve the policies and procedures used to direct and manage OPG, enhance shareholder value, and ensure financial viability.

Throughout 2006, OPG continued to demonstrate to our Shareholder our ability to improve performance and deliver on our commitments. This has led to increased confidence in the Company and its operations.

Policies approved by the Board in support of these objectives included the following:

- An updated Environmental Policy, replacing the company's Sustainable Development policy;
- A new Disclosure Policy to ensure that all public communications by the Company are disclosed in accordance with legal and regulatory requirements where applicable; and
- An updated Code of Business Conduct Policy affirming OPG's business values of integrity, excellence, and citizenship.

The Board also reviewed and approved revisions to OPG's Dam Safety Policy and reviewed OPG's Health and Safety Policy.

In addition, the Board received three directives in 2006 from OPG's shareholder, the Government of Ontario, instructing OPG to take certain actions with respect to our business. These included a directive instructing OPG to proceed to the definition stage for replacing and expanding its four hydroelectric stations on the Lower Mattagami River system; a directive to cancel the gas conversion of OPG's coal-fired generating station in Thunder Bay; and a directive instructing OPG to begin feasibility studies on refurbishing its existing nuclear units and to begin a federal approvals process, including an environmental assessment, for new nuclear units at an existing site. This latter directive effectively broadens OPG's mandate to include exploring options for the building of new nuclear facilities. Accordingly, the Board created a new committee to provide oversight and guidance to management as it implements this directive. In keeping with OPG's commitment to being an open and accountable company, the Board posts these directives on the company website, opg.com.

On behalf of the Board, I want to thank OPG management and employees for their efforts and achievements in 2006. We look forward to similar successes in 2007.

Jake Epp
Chairman

"OPG's performance has improved in many areas over the past few years…We are committed to maintaining this momentum."

JIM HANKINSON
President and CEO

President's Message

The year 2006 saw OPG continue to progress as a performance driven company and to deliver on the key strategic goals consistent with our mandate: reliable, efficient generation; asset improvement; capacity expansion; financial sustainability; and responsible corporate governance, environmental stewardship and corporate citizenship.

It was a year that saw our nuclear production at its highest level in five years; our fossil reliability at its best level in six years; our acid-gas emissions and emission rates at their lowest recorded levels; and our hydroelectric availability at 93 per cent – three per cent better than the industry's five year average.

It was also a year in which OPG continued to build credibility with our Shareholder and the public. This confidence is seen in the number of generation projects we have been asked to assess or undertake by the Ontario Government.

We also continued to improve the quality and efficiency of our assets through prudent investment in upgrades, new equipment and processes. Significant improvements were made in all asset categories.

In addition, we were directed by our Shareholder to begin a feasibility study on the potential refurbishment of the Pickering B nuclear station. While a final decision on whether to go forward with refurbishment will not be made until 2008, essential preliminary work – including the start of an Environmental Assessment – has begun. Additional work, including the preparation of a business case assessment, will continue throughout 2007. A solid business case must exist to justify any refurbishment.

We were also directed by our Shareholder to begin the federal approvals process for new nuclear units at an existing site. We began that process in September by filing a site preparation licence with the regulator for new nuclear units at our Darlington nuclear site. The Government's directive to explore nuclear refurbishment and new build options reflects confidence in our ability to manage and deliver large projects of this type.

This confidence was further reflected in several other new generation projects and studies. These include the Niagara Tunnel, the Lac Seul hydroelectric project in Northwestern Ontario, and the Portlands Energy Centre in downtown Toronto. These initiatives are in keeping with our mandate's focus on supply expansion to help meet Ontario's energy needs. We are also exploring the development potential of a number of hydroelectric sites in northern Ontario and are building commercial partnerships with First Nations.

At the management level, OPG strengthened its management structure with the appointment of OPG's former Chief Nuclear Officer, Pierre Charlebois, as Chief Operating Officer. Pierre's appointment reflects the high priority we place on the operations side of our business and our commitment to meet the many expectations of our Shareholder.

Financial performance also improved. Net income for the year ended December 31, 2006 was $490 million compared to $366 million in 2005, an increase of $124 million. In addition, OPG's short-term credit rating was upgraded by a major rating agency.

While net income in 2006 was higher than 2005, it is important to note that our 2005 net income was unfavourably impacted by a write-off of $265 million taken on our Lennox station and Pickering A Units 2 and 3. OPG's 2006 financial results reflected higher nuclear and hydroelectric production and improved reliability from our fossil stations. Net income in 2006 was also favourably impacted by a decrease in depreciation expense as a result of extending the lives for accounting purposes of our coal-fired stations and Pickering A and B nuclear stations. Factors which had an unfavourable effect on our net income included reduced revenues from a decrease in total generation caused by lower Ontario electricity demand and a decrease in average sales prices compared to 2005. Our financial results were also unfavourably affected by increased pension and other post employment benefit costs mainly as a result of changes in economic assumptions used to measure the costs.

Members of the Fix-It-Now team at the Pickering A nuclear generating station: the team's focus on fixing things right and meeting its commitments had a positive impact on Pickering A's performance in 2006. A similar commitment to getting the job done can be found among employees across OPG.

I am…grateful to our employees for the positive contribution they have made to our operations.

OPG continued to be an active and engaged participant in the regions and locales where we operate. More broadly, we took steps to communicate openly and transparently with Ontario residents about our operations. These steps included: publishing a semi-annual performance report; redesigning our website for easier use and access to information; and utilizing electronic, print and broadcast media.

In late 2006, charges were dismissed against OPG concerning the accidental drowning in June 2002 of a young mother and her son from a spillway release at our Barrett Chute hydroelectric station. Two OPG employees were also found innocent of charges relating to the incident. These tragic deaths left OPG with an indelible sadness coupled with an iron resolution to do everything possible to prevent this from happening again. We have since implemented many new and significant safety measures at our hydroelectric facilities. While these measures cannot undo the tragedy of four years ago, OPG will continue to enhance these safety measures as part of our absolute commitment to public safety.

OPG also launched and accelerated initiatives to improve the year's workplace safety performance; strengthen employee engagement; and attract and hire new employees as our workforce ages and many of its members approach retirement.

Efforts to strengthen workplace safety will be an especially important priority for OPG in 2007. Although many OPG sites achieved significant safety successes, our overall employee safety performance in 2006 deteriorated from 2005 levels. OPG is committed to improving our performance in this critical area through the leadership of senior management working together with our union partners, and all employees.

We will also focus on timely completion of planned outages at our nuclear stations. OPG performed six planned outages on nuclear units in 2006 in which much good work was accomplished to improve performance. But a number of these outages took longer than planned, reducing operating time, production, and capability factors.

Increases in our lower cost nuclear and hydroelectric production helped OPG continue to have a moderating effect on the price of electricity in 2006. The price OPG receives for electricity produced from its nuclear and large hydroelectric stations has been frozen by regulation since April 2005. OPG received an average price of 4.6¢/kWh from the output of its generating stations compared to the average electricity spot price in Ontario of 4.9¢/kWh. The 2006 spot price was affected by lower demand and was significantly lower than the 2005 average price of 7.2¢/kWh.

OPG's revenues and financial performance have been constrained for 2.5 years as a result of regulated pricing on much of our generation. OPG foresees a continuation of low electricity prices and slow growth in Ontario electricity demand. As well, increasing demands to take on new generation projects will put added pressure on cash flow. These forces could have a constraining effect on our future financial performance.

Our response to these challenges will be to continue to operate our assets in a cost-effective and commercially responsible manner. We will also focus on optimizing the funds generated from operations to finance current and new generation projects. To the extent that additional funds are required, we will continue to explore opportunities to diversify our funding sources beyond bank lines of credit and financing obtained from the Ontario Electricity Financial Corporation.

I am proud of the successes OPG achieved in 2006 and grateful to our employees for the positive contribution they have made to our operations. OPG's performance has improved in many key areas over the past few years. We have delivered on our commitments. We are fulfilling our mandate. We are earning the confidence and respect of our Shareholder. We have enhanced our credibility as a responsible and accountable organization in the eyes of our many stakeholders. We are committed to maintaining this momentum.

Jim Hankinson
President and CEO

DELIVERING ON GOALS

Report on Operations 2006

The Niagara Tunnel Boring Machine begins its 10.4 kilometre journey under the city of Niagara Falls. The 130-metre long machine is excavating a massive water diversion tunnel to enable OPG's Beck hydroelectric stations to generate more renewable hydroelectric energy.

ASSET PERFORMANCE

With a unit capability of 99.4%, Darlington Unit 2 was the world's fourth best performing CANDU reactor in 2006

Nuclear Production
(TWh)

46.9

Nuclear production grew by four per cent in 2006 and has increased every year since 2003.

Hydroelectric Availability
(%)

93%

The availability of OPG's hydroelectric stations in 2006 improved over 2005 levels and was three per cent better than the industry five year average.

Fossil Forced Outage Rate
(%)

14.1%

As measured by forced outage rate, the 2006 reliability of OPG's fossil-fuelled stations was the best since 2000.

Kakabeka Falls generating station in Northwest Ontario, the third oldest in OPG's fleet, celebrated its 100th year of producing electricity in 2006. Operating continuously since 1906, the 25 MW station has produced an estimated 14.7 billion KWh of electricity – enough power to meet the needs of approximately 1.5 million people for a year. To celebrate this event, the station held an open house in August attracting more than 1,000 visitors.

OPG's objective is to cost effectively produce electricity from its diversified generating assets. These assets performed well in 2006, producing 105.2 TWh – about 70 per cent of the electricity consumed in Ontario.

Nuclear

OPG's nuclear stations at Pickering and Darlington generated 46.9 TWh – an increase of four per cent over their 2005 production levels. This improvement was aided significantly by generation from OPG's Pickering A, Unit 1 reactor, which the company successfully returned to service in November 2005. While overall nuclear unit capability declined somewhat compared to 2005, three of OPG's 10 nuclear units achieved capability factors of above 90 per cent. Two of these units were ranked among the top 10 CANDU performers worldwide. The station-wide unit capability factor for the Pickering A station also rose. Representing about 30 per cent of OPG's generating capacity, our nuclear plants produced 45 per cent of the company's energy output in 2006.

Hydroelectric

OPG's 64 hydroelectric stations also produced more electricity than in the previous year. Total hydroelectric production for 2006 was 33.3 TWh compared to 32.6 TWh in 2005. The strong reliability of OPG's hydroelectric assets was reflected by the fact that in 2006, OPG's hydroelectric stations were available to produce power 93 per cent of the time. OPG benchmarks the performance of its hydro-electric stations against many of North America's top performers and compares very well in such key performance areas as availability and reliability. Safety performance during the year was excellent. In 2006, employees at our hydro-electric stations worked more than 2 million hours, or over one full year, without a lost time accident – the first OPG business unit to achieve such a milestone.

Fossil

In 2006, OPG's fossil stations produced 25.0 TWh compared to 30.9 TWh in 2005. This decrease was mainly due to lower electricity demand in Ontario and higher production from OPG's nuclear assets. Despite lower production, fossil plant reliability was strong as evidenced by significantly improved forced outage rates relative to 2005 and 2004. Their environmental performance was also excellent. Acid gas emissions and emission rates were the lowest recorded; and carbon dioxide levels were below 1990 levels, the Kyoto base-year – a drop of over 35 per cent since 2000.

OPG's fossil-fuelled plants also provide the generation capacity and flexibility to rapidly respond to changes in electricity demand thus helping Ontario to avoid short term price spikes and costly imports. In addition, much of OPG's fossil generation is subject to price restrictions which further moderate electricity prices in Ontario.

OPG's Nanticoke fossil-fuelled generating station was Ontario's second largest electricity producer next to OPG's Darlington nuclear station on August 1, 2006, when provincial demand soared to a record 27,005 MW. Nanticoke has reduced its environmental impact through the use of low nitrogen oxide burners; selective catalytic reduction equipment on two of its units; operational controls to maintain low nitrogen oxide emissions; improvements in particulate collection; and installation of new turbines to improve fuel efficiency.

ASSET IMPROVEMENT

OPG employees retrofit a new boiler feed pump at the Lambton fossil-fuelled station

Nuclear
(fuel channels inspected)

1,554

Inspection and maintenance of 1,554 fuel channels was completed at Pickering B – a key step toward improved reliability.

Hydroelectric
(MW)

+25

Equipment improvements at OPG's hydroelectric stations added 25 MW of renewable hydroelectricity capacity to Ontario's supply in 2006.

Fossil-Fuelled
(dollars)

$117 million

OPG invested approximately $117 million in improvements to its fossil-fuelled generating stations in 2006.

The Darlington Unit 1 outage, completed on time and on budget on December 14, was the best planned outage within OPG Nuclear in recent years. Management and employees worked together to ensure the outage was a success. Their achievements include: 11,000 tasks completed; 8,000 boiler tubes inspected; 11 km of new cable installed; three turbine blades changed; three feeder tubes replaced; and no lost time accidents.

OPG invests strategically in equipment, programs and people to enhance the efficiency and reliability of its generating stations and increase electricity production.

Improving our Nuclear Fleet

OPG has developed focused strategies and initiatives to improve the performance of its nuclear stations. In 2006, these led to progress and improvements on several fronts, including enhanced equipment reliability and improved plant condition.

Darlington: Darlington nuclear station completed two major planned unit outages. While the first of these outages (conducted on Unit 3) went over schedule, the learning gained helped employees deliver the second outage (conducted on Unit 1) on time and with a high degree of success. Notable achievements of the second outage included completion of Darlington's first ever multiple feeder pipe replacement program. This is an important step in enhancing Darlington's reliability and performance and extending its operating life.

To further improve performance, Darlington has launched an ambitious initiative to shift all its unit outages from 24-month to 36-month cycles by 2008. With the completion of its 2006 outage, Unit 3 became the first of Darlington's units to enter this new cycle. By 2008, all Darlington units are scheduled to be operating on three-year cycles between planned outages, improving plant reliability and generation output as a result.

Pickering A: A key performance objective for the Pickering A nuclear station was to successfully complete its planned Unit 4 Fall outage. While the outage went beyond schedule, key maintenance activities were completed – including feeder tube and boiler inspections as well as repairs to the boiler feedwater nozzle internals. Earlier in the year, Pickering A successfully completed a 15-day planned outage on its Unit 1 reactor. During this outage, a key deliverable – replacement of the heat transport pump motor stator coolers – was achieved five days ahead of schedule. The entire outage was completed safely and on time.

Pickering B: The Pickering B nuclear station completed the last phase of a major four-year inspection and maintenance program on 1,554 of its fuel channels. As a result, within every fuel channel at Pickering B no contact exists between the pressure tube and the calandria tube – a critical prerequisite for station longevity and improved performance. With this complex procedure complete, Pickering B is now able to move to shorter outages – resulting in longer operating runs and higher output.

The refurbishment of Pickering B will only take place if there is a solid business case to justify it.

Pickering B Refurbishment: OPG also began exploring the feasibility of refurbishing Pickering B. First steps in this process were taken in February 2006, with the creation of a special division within OPG dedicated to assessing the business case for possible life extension of both Pickering B and Darlington stations. In June, the Ontario government confirmed OPG's assessment activities by directing the company to begin feasibility studies on refurbishing its existing nuclear plants and to begin an Environmental Assessment (EA) on refurbishing Pickering B's four nuclear units. During the remainder of 2006, open houses were held under the EA to provide the public with refurbishment information and seek their input.

OPG has initiated a plant condition assessment and an integrated safety review to determine the scope of work required for a life extension of the generating station. These activities will be followed by conceptual engineering to establish the cost and schedule for the work. Early in 2008, OPG will be able to assess the business case. The refurbishment of Pickering B will take place only if there is a solid business case to justify it.

One of OPG's largest hydroelectric asset improvement projects, the Caribou Falls rehabilitation project involved staff from across OPG's Northwest Plant Group. With an average age of 72 years, OPG's hydroelectric assets have provided Ontario with a steady supply of clean, renewable electricity for many decades. The enhancements OPG is making to these stations will help ensure their continued contribution for decades to come.

Hydroelectric

OPG invests an average of $160 million a year to sustain and improve its existing hydroelectric assets. Improvements in 2006 included: runner upgrades at Abitibi Canyon and Ranney Falls; an overhaul and "rewind" at the Caribou Falls station; and upgrades to the switchgear at the Whitedog generating station in Northwest Ontario.

Since 1992, improvements like these have added 425 MW of additional capacity to OPG's hydroelectric supply – including 25 MW added during 2006. Future upgrades will add another 116 MW to OPG's hydroelectric capacity by 2015.

In addition to these improvements, OPG developed a new dispatch process which "aggregates" hydroelectric generation on the river systems where its hydro stations are located. The process improves efficiency and performance by giving OPG operators more flexibility in responding to dispatch instructions from Ontario's Independent Electricity System Operator (IESO), thereby reducing some of the equipment stress these instructions can cause and contributing to improved performance.

Fossil

The value of OPG's fossil-fuelled assets, like that of all our generating stations, is measured by their production performance. We also measure our fossil stations' performance by their ability to perform when needed. OPG took steps to improve both areas in 2006.

Production-related improvements included: installing a new high pressure turbine at the Nanticoke plant; initiating work leading to a major generator overhaul on Lambton's Unit 3; and replacing the original control system at the Thunder Bay coal-fired station in Northwest Ontario.

OPG also tested plans to better coordinate dispatch of units at its Nanticoke, Lambton and Thunder Bay stations. The initiative could alleviate some of the physical demands these units experience in responding to five-minute dispatch instructions from the IESO, improving plant efficiency and performance, and lowering emissions.

To further improve environmental performance at its fossil plants, OPG explored the use of biomass as a fuel. Successful test burns involving a mix of coal and carbon-neutral grain pellets were performed at the Thunder Bay and Nanticoke stations. Another fuel-mix initiative saw the Nanticoke station increase the portion of very low sulphur coal in its fuel blend.

To further improve environmental performance at its fossil plants, OPG explored the use of biomass as a fuel.

OPG also conducted new tests on existing emission reduction equipment used at the Lambton generating station. The tests showed that in addition to reducing acid gas emissions, the plant's combination of wet scrubbers and selective catalytic reduction technology cut mercury emissions by more than 90 per cent. The tests demonstrate that Lambton continues to better the standards established by air emission regulations.

In June 2006, the Ontario Ministry of Energy announced that Ontario's need for electricity would require further delays in its plan to replace coal-fired generation. In response, OPG reassessed its fossil-maintenance programs which had been geared to the previous shutdown timetable; undertook several environmental initiatives at Nanticoke to address issues such as heat rates, water temperatures, noise abatement and particulates; and hired more than 100 new OPG employees to maintain plant operating reliability as many employees approach retirement.

GENERATING CAPACITY

OPG's 12.5 MW Lac Seul hydroelectric generating station, under construction in Northwest Ontario

Niagara Tunnel
(kWh)

1.6 billion

The average amount of additional hydroelectric energy per year that will be produced by OPG's Beck generating stations once the Niagara Tunnel is completed towards the end of the decade.

Portlands Energy Centre
(MW)

550

The amount of capacity of the Portlands Energy Centre, being built in downtown Toronto by OPG and TransCanada Energy Inc., to help meet Toronto's growing energy needs.

Nuclear New Build
(community information sessions)

5

In 2006, OPG held five community information sessions to inform local residents and seek their input on its activities with respect to potential new nuclear units at OPG's Darlington site. More than 200 people attended these sessions.

The Darlington nuclear site, potential home of new nuclear units to generate power for Ontario's future. OPG believes Darlington is an excellent site for new nuclear. Its advantages include: enough room to build; proximity to a major transmission corridor; supportive host communities; a highly skilled and experienced workforce.

To help meet Ontario's electricity needs, OPG has embarked on a major campaign to increase its capacity through new generation projects. OPG acts as project manager on these initiatives, contracting with third party firms who assume much of the risk for constructing the projects on time and on budget.

Niagara Tunnel: Work on the Niagara Tunnel progressed in 2006 with the launch of "Big Becky", the world's largest hard rock tunnel boring machine (TBM). The Tunnel's builder is Strabag AG of Austria, a company with extensive experience in large tunnel construction. Excavation, which began in September, got off to a slow start but is expected to recover as the TBM encounters Queenston shale, a more uniform rock layer through which about 80 per cent of the tunnel will be excavated. As OPG's largest capital project, the Niagara Tunnel will divert more water to the Beck hydroelectric complex providing the station with the capability to generate an additional 1.6 billion kilowatt hours of renewable hydroelectricity for Ontario. The project is scheduled to be completed in late 2009.

Lac Seul: The 12.5 MW Lac Seul hydroelectric station in Northwest Ontario is being constructed by SNC Lavalin Inc. Begun in 2005, construction progressed in 2006 to include completion of the powerhouse substructure, erection of the powerhouse frame and substantial completion of the water conveyance tunnel. Throughout 2006, work proceeded safely, with no lost time injuries or "near miss" safety incidents.

Lower Mattagami: OPG is exploring the feasibility of replacing and upgrading stations on the Lower Mattagami River system in Northeastern Ontario. This 450 MW potential project moved from "concept" to "definition" stage in 2006 under direction from the Ontario government. The new phase involves environmental planning, solicitation of design/build proposals, securing of approvals, and discussions with First Nations and other stakeholders.

Other hydroelectric projects: In 2006, OPG had four other hydroelectric projects in the definition stage of development, representing about 55 MW of new hydroelectric capacity for the Province. Early planning work was also underway on several other projects whose potential and feasibility is still being assessed.

Portlands Energy Centre: In October 2006, construction began on the Portlands Energy Centre – a 550 MW high-efficiency, combined cycle natural gas generation plant. OPG and TransCanada Energy are building the plant in downtown Toronto to help meet the city's growing electricity needs. During 2006, Portlands signed a 20 year Accelerated Clean Energy Supply contract with the Ontario Power Authority. The facility is scheduled to be operational in simple cycle mode delivering 340 MW by June 1, 2008. When fully finished in 2009, it will provide up to 550 MW in combined cycle mode – representing about 25 per cent of central Toronto's needs.

Lakeview: A second fossil-based supply initiative involves OPG's Lakeview site in Mississauga, Ontario. Previously home to OPG's decommissioned Lakeview coal-fired station, the site is being considered as the location for a potential new gas-fuelled generating plant. A proposal to replace the older facility with a new station was announced by OPG in June 2006. OPG is partnering with Enersource Hydro Mississauga Services Inc. on this potential project.

New Build Nuclear: Potentially OPG's most significant contribution to new electricity supply, this initiative could see OPG participating in the construction of new nuclear units. In September, OPG filed an application with its regulator, the CNSC, for a Site Preparation Licence for new nuclear units at its Darlington nuclear site. The application was submitted following a June 2006 directive by the Ontario Minister of Energy instructing OPG to begin the federal approvals process for new nuclear units at an existing site. Following its site application submission, OPG held five Community Information Sessions in Clarington and Oshawa municipalities to share information with local residents about its activities with respect to the proposed new nuclear units. A special section of OPG's website was also created to provide information on the subject.

The potential new build initiative enjoys strong municipal and local community support. It also represents a vote of confidence by our Shareholder in OPG's ability to manage large capital projects and meet its commitments.

SAFETY, SECURITY & THE ENVIRONMENT

Pickering B's Riley Saunders takes "personal responsibility for safety" to help OPG achieve its goal of zero injuries

Safety
(years)

1.3

OPG's nearly 1,000 Hydro employees achieved 1.3 years without a lost time accident – one of many safety successes achieved by OPG sites.

Security
(dollars)

$300 million

The amount OPG has invested in security enhancements to its nuclear facilities since 2001.

Environment

300,000

Number of native trees and shrubs planted in Ontario in 2006 by OPG under its biodiversity program.

The Mattagami Lake Dam in Northeast Ontario is among the 64 hydroelectric stations and 240 dams that OPG operates across Ontario. To ensure safety at these facilities, OPG administers an extensive Water Safety Program to educate and protect the public. Initiatives undertaken in 2006 included: installing video surveillance cameras and improved safety booms at several of its stations and installing a new safety fence near the R.H. Saunders generating station on the St. Lawrence River.

As one of Ontario's major power producers, OPG has an impact on the society in which it operates. OPG is aware of this impact and is dedicated to operating at the highest levels of safety, security and environmental responsibility.

Workplace Safety

While OPG maintained its strong commitment to workplace safety and advanced on a number of safety management fronts, we were not satisfied with our safety performance in 2006 relative to our strong past performance in this area. Although many individual sites and businesses achieved excellent safety results, the company's overall performance deteriorated from 2005 levels. This was due to increased on-the-job injuries and a higher number of "close call" incidents where serious injury could have occurred, but was avoided.

In 2006, radiation levels at both Pickering and Darlington were again significantly below the levels Canadians receive from natural sources...

OPG's 2006 All Injury Rate (AIR) was 1.30 injuries per 200,000 hours worked. This was better than 2005 performance of 1.33 injuries per 200,000 hours, and within the top quartile (2003-2005 rolling average) set by the Canadian Electricity Association (CEA).

OPG's 2006 Accident Severity Rate (ASR) was 5.87 days lost per 200,000 hours worked. This was worse than our 2005 ASR of 2.03 days lost per 200,000 hours.

OPG is committed to continuous improvement in safety performance and striving for zero workplace injuries. To achieve these goals, targetted strategies have been developed focusing on: improvement in risk-based safety management systems; innovative communications to strengthen safety culture; and programs to address safety risk areas such as electrical safety, musculoskeletal disorders, and fall management programs.

OPG continued to demonstrate safety leadership in 2006 through:

- an ongoing commitment to young worker safety in communities where we operate; and
- employees sharing their expertise and OPG's safety-related best practices with other companies and industry associations to help improve workplace safety across all industries.

Public Safety

OPG adheres to very high standards of public safety and regulatory compliance at all its facilities. At the company's nuclear operations, for example, safety and security take precedence over everything else. In 2006, radiation levels at both Pickering and Darlington were again significantly below the levels Canadians receive from natural sources such as sunlight as well as many times lower than levels permitted by government regulation.

OPG places an equally strong emphasis on managing its nuclear waste. In 2006 OPG strengthened its nuclear waste capability by expanding its used fuel storage facilities and undertaking an environmental approval process for its proposed Deep Geologic Repository near Kincardine, Ontario.

Security

In the past five years, OPG has spent over $300 million in security upgrades at its nuclear facilities to ensure public and employee safety. To further enhance the already strong security measures in place at its nuclear facilities, OPG opened two new, state-of-the-art security buildings respectively at its Pickering and Darlington nuclear sites. The buildings are equipped with robust security screening equipment – including detecting devices for potential explosives, X-ray machines and metal detectors, and geometric hand monitors to authorize access into protected areas of the stations.

The main security building at the Darlington nuclear generating station is one of the new security buildings at OPG's nuclear facilities. These buildings are state-of-the-art facilities in which OPG security staff can perform important search functions while getting employees to work safely and securely.

Environment

Through its updated Environmental Policy and initiatives, OPG seeks to mitigate its impact on the environment. The Company is committed to meeting its legislative and voluntary obligations with respect to the environment. OPG's voluntary obligations include initiatives such as its Environmental Site Assessment and Biodiversity Management programs and its commitment to phase out PCBs. Our environmental commitments cover a broad range of areas, including: spills management, regulatory compliance, fossil air-emissions, radiation emissions, waste management, energy efficiency and promoting sustainable development education among employees. OPG also contributes to the environmental well-being of the communities where its facilities operate, primarily through its ongoing, Ontario-wide tree-planting program. The Company reports regularly on its performance in meeting its environmental commitments in its Sustainable Development Annual Report, on its website, and in newsletters published by its plants.

OPG's environmental commitment was reflected in a number of areas in 2006.

Acid gas emissions fell significantly due primarily to lower fossil production levels due to lower demand and environmental improvements. Reduced production also contributed to decreased carbon dioxide emissions, which were lower in 2006 than they were in 1990. In addition to these environmental achievements, Units 3 and 4 at the Lambton generating station have been identified as two of the 10 cleanest coal-fuelled units in North America.

OPG also achieved internal energy efficiency savings of 51,600 MWh – enough electricity to power about 4,300 homes – exceeding its target of 26,500 MWh and avoiding the release of 50,568 tonnes of carbon dioxide.

An aspect of OPG's energy efficiency performance was recognized during the year by Natural Resources Canada's Commercial Building Incentive Program, which named OPG's new nuclear security buildings in Darlington and Pickering as highly energy efficient in design.

Another notable achievement in 2006 was the Wildlife Habitat Council's (WHC) certification of OPG's Atikokan and Lennox generating stations, bringing the total number of OPG's stations certified under the WHC to eight. Each of OPG's fossil and nuclear plants and all of its hydroelectric plant groups have developed their own biodiversity plans to protect surrounding habitats.

As part of its sustainable development commitment, OPG expanded its sustainable development education and training beyond supervisors to include all employees. This initiative will continue through 2007 to 2011 to fulfill a key principle of the company's updated Environmental Policy – that environmental stewardship is the responsibility of all OPG employees. More than 600 employees received such training in 2006.

Paula Sanders and her son Brady engage in tree planting near OPG's Atikokan coal-fired station. Working with Scouts Canada, Atikokan has planted about 6,500 pine and spruce seedlings on site between 2004 and 2006. As part of its Biodiversity Management Program and Greenhouse Gas Management Strategy, OPG has planted more than 300,000 native trees across Ontario in 2006 – bringing the total planted since 2000 to 2.5 million. Over their lifetime, it's estimated the trees will trap and offset approximately 1 million tonnes of carbon dioxide.

EMPLOYEES AND COMMUNITY

Tuesdays on the Waterfront Trail near Darlington Nuclear GS: one of many community programs OPG helps support

Charity Campaign
(dollars)

$1.79 million

OPG employees and pensioners donated this amount in 2006 to the company's annual Charity Campaign to help the less fortunate.

Corporate Citizenship
(number of initiatives)

850

OPG helped support more than 850 community, environmental and educational initiatives in 2006 through its Corporate Citizenship Program.

OPG Workforce
(student employees)

400

In 2006, OPG hired about 400 young people into student positions. In addition to their contribution to OPG, these students return to their schools as ambassadors for OPG.

Management's Discussion and Analysis

Contents

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2006. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. Certain prior year information has been reclassified to conform to the current year's presentation. This MD&A is dated February 15, 2007.

Forward-Looking Statements

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, asset performance, nuclear decommissioning and waste management, closure of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post employment benefit ("OPEB") obligations, income taxes, spot market electricity prices, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, and the weather. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

Through events like this Nuclear Graduate Recruitment gathering, OPG is actively adding to its supply of new employees. OPG's recruitment approach includes a focused strategy that targets highly qualified graduates in engineering and the technical professions. As part of this strategy, OPG hired 80 university graduates in 2006.

People are OPG's great strength. Our employees are the source of our success. The communities where we operate give us licence to operate. We are dedicated to meeting their expectations.

Employees

OPG employs more than 11,500 men and women united by a common commitment to generate reliable electricity in a responsible manner. This serious and often challenging task requires skilled and qualified individuals working in roles that require a high degree of professional training, education and competence. OPG goes to significant lengths to create a workplace that attracts such employees, makes them feel valued, and gives them the opportunity to develop and progress. These objectives were advanced in 2006 through initiatives such as:

- large-scale recruiting resulting in the hiring of many new employees with post-secondary degrees;
- development and implementation of bias-free pre-employment selection tools to support new and emerging hiring activity in OPG's fossil and hydroelectric businesses; and
- continued recognition of employee performance through written and verbal commendation from management, peer recognition and OPG's Power Within Achievement Awards to acknowledge top performers.

In addition to these initiatives, OPG was honoured to be named as one of Toronto's Top 50 Employers for 2006. The award recognized OPG's leadership in attracting quality employees and providing them with excellent career opportunities and benefits.

In 2006, OPG launched a company-wide Employee Survey to track employee engagement levels. The survey showed a significant improvement in engagement scores since 2004, but only a slight increase in these scores since 2005. Initiatives are underway to enhance employee engagement in 2007.

Community

Many OPG employees contribute significantly to their communities by giving generously of their resources and time. In 2006, employees and pensioners donated nearly $1.8 million through OPG's annual Charity Campaign to assist those in need and organizations that help them.

OPG employees also contribute to their communities as members of local organizations, participants in community events, and volunteers for numerous worthy causes. They exemplify OPG's values, and we are proud of the commitment and contribution they are making to their society and communities.

...OPG was honoured to be named as one of Toronto's Top 50 Employers for 2006.

OPG supports communities at the corporate level through its Corporate Citizenship Program (CCP). In 2006, OPG invested through CCP more than $1.8 million to help support over 850 educational, environmental and community initiatives in Ontario. These initiatives are primarily in communities that host OPG generating facilities.

OPG has built productive and positive relationships with many of its site communities, several of which have hosted our facilities for many decades.

OPG is also working with First Nations communities to address past grievances and develop commercial partnerships based on mutual trust and respect. In 2006, OPG signed four agreements with First Nations that help pave the way to stronger relationships. These are central to the success of a number of potential hydroelectric projects the company is exploring in northern Ontario.

In 2006, OPG's Kakabeka Falls hydroelectric station celebrated 100 years of serving local communities in Northwest Ontario near Thunder Bay, and the Pickering nuclear generating station celebrated 40 years of being part of the Durham community. This past year, the City of Pickering honoured OPG's community commitment by awarding the station its Civic Award. The award is given annually to local businesses that demonstrate outstanding support and participation in community activities. OPG also received the Business of the Year award from the Kincardine & District Chamber of Commerce for its "excellence in business growth, customer service and community leadership."

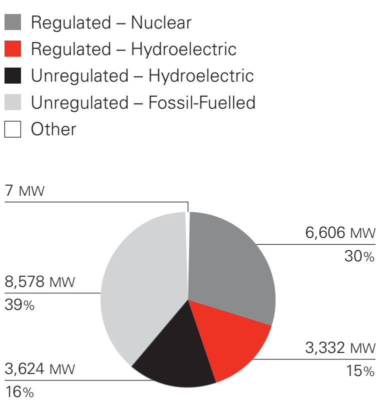
The Company

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was created under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

At December 31, 2006, OPG's electricity generating portfolio had an in-service capacity of 22,147 megawatts ("MW"). OPG's electricity generating portfolio consists of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (which includes a 50 per cent interest in the Huron Wind joint venture). In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach gas-fired generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that the company operates became rate regulated. OPG continues to receive the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit on the majority of this output. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Beginning in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified accordingly.

In-Service Generating Capacity by Segment
December 31, 2006
22,147 MW



Rate Regulation

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004* (Ontario), which provides that, effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours ("MWh") of production from the regulated hydroelectric facilities in any hour is $33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric electricity production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price. The regulated price received by OPG for production from the nuclear facilities is $49.50/MWh (4.95¢/kWh). These regulated prices were established by the Province, based on a revenue requirement taking into account a forecast of production volumes and total operating costs, and a return on rate base, which assumed an average five per cent return on equity. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets, deferred charges and an allowance for working capital. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that new regulated prices to be established by the Ontario Energy Board ("OEB") will take effect.

The regulation directed OPG to establish variance accounts for costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions; unforeseen changes to nuclear regulatory requirements or unforeseen technological changes; changes to revenues for ancillary services from the regulated facilities; acts of God (including severe weather events); and transmission outages and transmission restrictions. In addition, the regulation directed OPG to establish a deferral account for non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A nuclear generating station.

An amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) was made in February 2007. The amendment clarified certain aspects of the regulation and directed OPG to establish a deferral account related to certain changes in its liability for nuclear used fuel management and its liability for nuclear decommissioning and low and intermediate level waste management.

The amendment directed OPG to establish a deferral account to record, up to the effective date of the OEB's first order establishing regulated prices, the revenue requirement impact, as reflected in OPG's audited consolidated financial statements, of any changes in its nuclear liabilities arising from an Approved Reference Plan, approved after April 1, 2005, in accordance with the terms of the Ontario Nuclear Funds Agreement ("ONFA").

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets are also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were excluded from the revenue limit rebate. The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning May 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these two revenue limits are returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers.

The implementation of regulated pricing for the generation from most of OPG's baseload hydroelectric stations and the nuclear generating stations that OPG operates, as well as the revenue limit on OPG's unregulated generating assets, replaced OPG's rebate obligations under the Market Power Mitigation Agreement effective April 1, 2005.

From market opening on May 1, 2002, and prior to April 1, 2005, OPG was required under its generation licence issued by the OEB to comply with prescribed market power mitigation measures, including a rebate mechanism. Under the Market Power Mitigation Agreement, OPG had been required to pay a rebate to the IESO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for the amount of energy sales subject to the rebate mechanism for those generating stations that OPG continued to control. The IESO passed the rebate on to consumers. The amount of energy generated by OPG that was subject to the rebate mechanism was approximately 80 terawatt hours ("TWh") on an annual basis.

Highlights

Overview of Results

This section provides an overview of OPG's audited consolidated operating results. A detailed discussion of OPG's performance by reportable business segment is included under the heading, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2006**	2005
Revenue		
Revenue before revenue limit and Market Power Mitigation Agreement rebates	**5,725**	6,949
Revenue limit rebate	**(161)**	(739)
Market Power Mitigation Agreement rebate	**–**	(412)
	5,564	5,798
Earnings		
Income before the following:	**791**	1,020
Impairment of long-lived assets	**22**	265
Income before interest, income taxes and extraordinary item	**769**	755
Net interest expense	**193**	197
Income before income taxes and extraordinary item	**576**	558
Income tax expenses	**86**	118
Income before extraordinary item	**490**	440
Extraordinary item	**–**	74
Net income	**490**	366
Electricity production (TWh)	**105.2**	108.5
Cash flow		
Cash flow provided by operating activities	**397**	1,201

Net income for the year ended December 31, 2006 was $490 million compared to $366 million in 2005, an increase of $124 million. Income before income taxes for the year ended December 31, 2006 was $576 million compared to income before taxes and an extraordinary item in 2005 of $558 million, an increase of $18 million. During 2005, OPG recorded a one-time extraordinary loss of $74 million to reflect the impact of adopting rate regulated accounting for income taxes effective April 1, 2005.

The following is a summary of the factors impacting OPG's results for the year ended December 31, 2006 compared to results in 2005, on a before-tax basis:

(millions of dollars – before tax)	
Income before income taxes and extraordinary item for the year ended December 31, 2005	**558**
Changes in gross margin	
Decrease in electricity sales prices after revenue limit and Market Power Mitigation Agreement rebates	(83)
Change in electricity generation by segment:	
Regulated – Nuclear	96
Regulated – Hydroelectric	(7)
Unregulated – Hydroelectric	46
Unregulated – Fossil-Fuelled	(181)
Trading revenue	58
Ancillary revenue	64
Other changes in gross margin	(28)
	(35)
Increase in pension and other post employment benefit costs	(177)
Increase in maintenance and repairs primarily for the nuclear and fossil-fuelled generating stations	(57)
Increase in nuclear planned outages	(46)
Amortization of Pickering A Return to Service deferral account balance	(21)
Write-off of excess inventory related to Pickering A Units 2 and 3 in 2005	57
Decrease in depreciation expense primarily due to extension of service lives of the coal-fired generating stations, Pickering B station and Unit 4 of the Pickering A station	89
Other changes	(35)
Decrease in income before income taxes, excluding impairment of long-lived assets	**(225)**
Impairment of long-lived assets – 2005	265
Impairment of long-lived assets – 2006	(22)
Income before income taxes for the year ended December 31, 2006	**576**

Earnings for the year ended December 31, 2006 were significantly affected by a reduction in gross margin from electricity sales due primarily to lower average sales prices and lower electricity generation compared to 2005. The decrease in electricity prices was primarily due to lower average Ontario spot market prices applicable to electricity generation from OPG's unregulated business segments. OPG's lower electricity generation during 2006 was primarily due to lower electricity demand in Ontario and higher generation from non-OPG generating stations, which contributed to reduced generation at OPG's fossil-fuelled stations. The lower generation from the fossil-fuelled generating stations was partially offset by higher generation from OPG's nuclear and unregulated hydroelectric generating stations.

Gross margin in 2006 was favourably affected by an increase in ancillary revenue compared to 2005, primarily due to revenue from the Lennox reliability must-run ("RMR") contract, and a higher margin on trading activities. The RMR contract, which commenced effective October 1, 2005, is a cost-based contract with the IESO that provides for regular payments, which are subject to adjustments for actual costs.

For the year ended December 31, 2006, OM&A expenses were $2,777 million compared to $2,516 million in 2005. The higher OM&A expenses were primarily due to an increase in pension and OPEB costs mainly due to changes in economic assumptions used to measure the costs. In 2006, OM&A expenses also included amortization of the Pickering A return to service costs, which were previously deferred in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario). Amortization commenced late in 2005 with the return to service of Unit 1 at the Pickering A nuclear generating station. In addition, the nuclear and fossil-fuelled business units incurred higher costs during 2006 as a result of an increase in repairs and maintenance expenditures for both planned and unplanned outages. In 2005, OM&A expenses were affected by a write-off of excess inventory acquired for the anticipated return to service of Units 2 and 3 at the Pickering A nuclear generating station.

Earnings were favourably affected by a decrease in depreciation expense of $89 million during 2006 compared to 2005. The decrease in depreciation expense was primarily due to a service life extension, for accounting purposes, of the Nanticoke generating station during the third quarter of 2005, and the subsequent extension of the service lives of all of the coal-fired generating stations during the third quarter of 2006, as a result of delays in the plan to replace coal-fired generation. In addition, in late 2005 and early 2006 respectively, OPG extended the remaining service lives of the Pickering A and B nuclear generating stations for purposes of calculating depreciation. This reduction was partially offset by an increase in depreciation expense due to the return to service of Unit 1 at the Pickering A nuclear generating station in November 2005 and other fixed asset additions during 2006.

OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations in 2006 of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result of changes in circumstance, which included a decrease in forecast Ontario spot market prices and the extension of the lives of the coal-fired stations. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives.

OPG recorded an impairment charge of $202 million related to its Lennox generating station in the first quarter of 2005, which contributed to higher earnings in 2006 relative to 2005. It was determined that the Lennox generating station, as a relatively high variable cost plant, would not be able to recover its carrying value from the wholesale electricity market in the future. Earnings were also reduced in 2005 as a result of the impairment charge of $63 million related to Units 2 and 3 at the Pickering A nuclear generating station. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. The impairment charge represented the carrying value, including construction in progress of these two units.

In 2006, legislation was passed which eliminated the Large Corporations Tax and reduced future income tax rates. The Large Corporations Tax for the year ended December 31, 2005 was $28 million. During the second quarter of 2006, OPG recorded a $19 million increase in earnings to reflect the reduction in future income tax rates.

Net income during the year ended December 31, 2006 reflected the impact of accounting for income taxes for the regulated segments of the business using the taxes payable method for the entire year. Net income for the year ended December 31, 2005 reflected the impact of the taxes payable method for only nine months, as this method was adopted upon inception of rate regulation on April 1, 2005. For the year ended December 31, 2006, OPG did not record a future income tax expense of $89 million, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. Net income for year ended December 31, 2005 reflected the impact of not recording a future income tax expense of $157 million. In the second quarter of 2005, as part of the transition to rate regulated accounting, OPG eliminated a net future income tax asset balance of $74 million related to rate regulated segments and recorded a corresponding one-time extraordinary loss.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable business segment, net of the revenue limit rebate for the period from April 1, 2005 to December 31, 2006, and net of the Market Power Mitigation Agreement rebate up to the inception of rate regulation on April 1, 2005, were as follows:

(¢/kWh)	**2006**	2005
Weighted average hourly Ontario spot electricity market price	**4.9**	7.2
Regulated – Nuclear	**4.9**	4.7
Regulated – Hydroelectric[1]	**3.5**	4.1
Unregulated – Hydroelectric[2]	**4.6**	5.2
Unregulated – Fossil-Fuelled[2]	**4.8**	5.5
OPG's average sales price	**4.6**	4.9

1 During the period from April 1, 2005 to December 31, 2006, electricity generated from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

2 During the period from April 1, 2005 to December 31, 2006, 85 per cent of the electricity generated from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit. The revenue limit was based on an average price of 4.7¢/kWh from April 1, 2005 to April 30, 2006, and decreased to 4.6¢/kWh effective May 1, 2006.

OPG's average sales price for the year ended December 31, 2006 was 4.6¢/kWh compared to 4.9¢/kWh for 2005. The decrease in OPG's average sales price was due to lower Ontario spot market prices, partially offset by the impact of the introduction of regulated prices and other related regulatory changes effective April 1, 2005. Ontario spot market prices were considerably lower in 2006 primarily as a result of lower demand, higher production from low marginal cost generation, and lower natural gas prices.

As a result of regulated prices and the revenue limit rebate, OPG's average sales price continued to be lower than the weighted average hourly Ontario spot electricity market price.

Electricity Generation

Total electricity generation during the year ended December 31, 2006 from OPG's generating stations was 105.2 TWh compared to 108.5 TWh in 2005. Electricity generation from nuclear stations increased primarily as a result of the return to service of Unit 1 at the Pickering A nuclear generating station in November 2005. Also, during the second quarter of 2005, Unit 4 at the Pickering A nuclear generating station was shut down for the duration of the quarter due to the inspection and repair of feeder pipes. OPG's fossil-fuelled generation was impacted by lower electricity demand in Ontario, higher non-OPG generation, and the increase in electricity generation from OPG's nuclear generating stations.

OPG's results are affected by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of Heating and Cooling Degree Days for the years ended December 31:

	2006	2005
Heating Degree Days[1]		
Total for year	**3,346**	3,749
Ten-year average	**3,626**	3,704
Cooling Degree Days[2]		
Total for year	**391**	551
Ten-year average	**372**	356

1 Heating Degree Days are recorded on days with an average temperature below 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport.

2 Cooling Degree Days are recorded on days with an average temperature above 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport.

Heating Degree Days for 2006 decreased compared to 2005 primarily due to warmer weather in Ontario during the winter, early spring, and December of 2006. The warmer temperature reduced electricity demand in Ontario in 2006.

Cooling Degree Days for 2006 decreased compared to 2005. Ontario experienced lower temperatures during the summer of 2006 compared to the same period in 2005, which also contributed to lower demand for electricity in Ontario in 2006.

Cash Flow from Operations

Cash flow provided by operating activities for 2006 was $397 million compared to $1,201 million during 2005. The decrease in cash flow from operating activities was primarily due to lower revenue before rebates as a result of lower Ontario spot electricity market prices, partially offset by the impact of lower expenditures on fuel and higher non-energy revenue.

Recent Developments

Appointment of Chief Operating Officer

In December 2006, OPG announced the appointment of Mr. Pierre Charlebois as Chief Operating Officer. Mr. Charlebois served as OPG's Chief Nuclear Officer from December 2003 to November 2006. The appointment reflects OPG's commitment to improve the operational effectiveness of OPG's nuclear, hydroelectric and fossil-fuelled generating businesses.

Lennox Generating Station

In January 2007, the OEB issued a decision approving a second RMR contract between OPG and the IESO for the Lennox generating station, for the period from October 1, 2006 to September 30, 2007. RMR contracts are designed to ensure that generating stations remain available to produce electricity when called upon in order to maintain the reliability of the electricity system. In its decision, the OEB deemed it appropriate for OPG to recover the fixed and variable operating costs of the Lennox generating station that are not recovered through market revenues. The RMR contract is a cost-based contract that provides for regular payments, which are subject to adjustments for actual costs.

Vision, Core Business and Strategy

OPG's mandate is to cost effectively produce electricity from its diversified generation assets, while operating in a safe, open and environmentally responsible manner. To accomplish its mandate and strategic objectives, OPG is focused on the following four corporate strategies: improving generating asset performance; increasing its generating capacity; achieving financial sustainability; and achieving excellence in corporate governance, safety, social responsibility, corporate citizenship and environmental stewardship.

Improving the Performance of Generating Assets

Nuclear Generating Assets

OPG's strategic objective is to operate the Darlington and Pickering A and B nuclear generating stations in a safe, efficient and cost effective manner, while undertaking prudent investments to improve their reliability and operating performance. To achieve these objectives, various programs and initiatives have been implemented to improve safety performance, improve the material condition and reliability of the operating units, optimize planned outages, reduce maintenance backlogs, mitigate technological risks through comprehensive inspection and testing programs, focus on production unit energy costs, and continue to address human resource demographic issues.

OPG is in the process of placing Units 2 and 3 at the Pickering A nuclear generating station in a safe state for the remaining life of the station and an additional 30-year period prior to dismantlement. This project involves de-fuelling the reactors, removing all heavy water, and reconfiguring the station, including the control room, as a two unit station. These activities must be conducted while meeting nuclear, radiological, industrial safety, and environmental protection standards.

Pursuant to the direction from the Minister of Energy in June of 2006, OPG has begun a feasibility study on the refurbishment of its Pickering B and Darlington nuclear generating facilities. OPG has initiated an assessment of the feasibility for refurbishing the Pickering B nuclear generating station to support its continued operation beyond 2015. The assessment will be a systematic, thorough review of the safety, environmental, financial and logistical aspects of refurbishment and continued operation of the nuclear generating station. OPG received confirmation from the Canadian Nuclear Safety Commission ("CNSC") that a Federal Environmental Assessment ("EA") is required prior to the refurbishment of the Pickering B nuclear generating station. The CNSC intends to issue draft guidelines outlining issues to be considered and included in the EA. The results of the EA will be documented in an EA study report, which will be publicly available. It is expected that an EA report will be ready in late 2007. OPG plans to make a recommendation to its Board in the first quarter of 2008. Following this, work will begin on the assessment of the business case for refurbishing the Darlington units.

Hydroelectric Generating Assets

OPG's strategic objective is to improve production from its existing hydroelectric generating assets in a cost effective and efficient manner. To achieve this objective, prudent investments will be made to maintain and/or improve the condition, reliability and efficiency of the hydroelectric generating assets. Programs and initiatives are underway to increase the availability of existing stations by replacing aging and obsolete equipment, accelerating runner upgrades, and enhancing maintenance practices. Performance improvements will be pursued while maintaining OPG's focus on employee and public safety, dam safety, environmental stewardship, and community relations. In 2006, hydroelectric capacity increased by 25 MW as a result of runner upgrades at three unregulated hydroelectric generating stations. In addition, plans are being developed for the conversion of Sir Adam Beck 1, Unit 7 from a 25 to 60 cycle load requirement. The conversion would increase hydroelectric generating capacity by an estimated additional 58 MW, and would be in service for early 2009.

Fossil-Fuelled Generating Assets

OPG's strategic objective is to maintain the productive capability of its coal-fired generating facilities, while continuing to operate in compliance with all applicable laws and regulations. To achieve this objective, various initiatives are in place to address the impacts of increased unit starts and stops, in part due to the role that the fossil-fuelled plants perform as intermediate and peaking facilities. In addition, OPG will ensure continued environmental compliance, and recruit and retain staff to ensure adequate expertise is available to both operate and maintain the units until their closure.

In June 2006, the Ministry of Energy announced that, as a result of additional capacity requirements to maintain system reliability, further delays will be necessary in the plan to replace coal-fired generation by 2009. The Minister directed the OPA to determine how best to replace coal-fired generation in the earliest practical timeframe and recommend options for cost effective measures to reduce air emissions from coal-fired generation. In its November 2006 publication titled "Ontario's Integrated Power System Plan, Discussion Paper 7: Integrating the Elements – A Preliminary Plan", the OPA indicated that coal-fired generation potentially could be replaced by 2011–2012. The report also indicated that reliability considerations suggest, however, retaining the option of maintaining about 3,000 MW of coal capacity until 2014 as insurance against possible delays in acquiring other resources. Plans to reduce the environmental impacts of coal-fired generation that remain in service are currently being evaluated.

Maintenance programs and performance improvement initiatives at OPG's coal-fired generating stations that were appropriate for an earlier shutdown have been re-assessed assuming longer plant operations. Several environmental initiatives have also been undertaken at both the Nanticoke and Lambton generating stations to address a number of key issues such as particulates, heat rates, water temperatures and noise abatement. Deferral of coal-fired plant closures has resulted in a further review of staffing requirements and strategies including focused recruiting efforts to maintain plant operating capability.

Increasing OPG's Generating Capacity

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generating capacity through expansion and redevelopment of its existing sites, as well as the pursuit of new projects where feasible. In addition, OPG, in consultation with its shareholder, plans to increase its generating capacity by exploring and developing, where feasible, natural gas and nuclear opportunities in Ontario. OPG will undertake these investments on its own or through partnerships. OPG is currently involved in the following hydroelectric, natural gas and nuclear generation projects.

Niagara Tunnel

The Niagara tunnel project will increase the amount of water flowing to existing turbines at OPG's Sir Adam Beck generating stations in Niagara, allowing the stations to utilize available water more effectively. Average annual generation is expected to increase by about 1.6 TWh.

In September 2006, on-site assembly of the tunnel boring machine was completed and excavation of the tunnel commenced. The intake configuration required the replacement of the existing accelerating wall and the installation of a cellular cofferdam, which were completed in 2006. The project is expected to be completed in late 2009.

The project is expected to cost approximately $985 million. Capital project expenditures for the year ended December 31, 2006 were $161 million and life-to-date capital expenditures were approximately $244 million. The project is debt financed through the Ontario Electricity Financial Corporation ("OEFC").

Lac Seul

OPG is constructing a new 12.5 MW hydroelectric generating station on the English River. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded and construction started during the first quarter of 2006, with the in-service date planned for the fourth quarter of 2007. Total project costs are expected to be $47 million.

In 2006, the water conveyance tunnel, the tailrace channel excavation, and the intake cofferdam were substantially completed. The powerhouse civil foundation and superstructure were completed in January 2007. Major sub-assemblies have been delivered to the site and pre-installation work has started. Capital project expenditures for the year ended December 31, 2006 were approximately $24 million and life-to-date capital expenditures were approximately $27 million. OPG has negotiated the project's debt financing with the OEFC and is in discussions with the OPA for a contract for the production from the new facility.

Lower Mattagami

In May 2006, OPG provided development alternatives to the Province to increase the generating capacity of four hydroelectric generating stations on the Lower Mattagami River. The incremental capacity associated with these alternatives ranged from approximately 140 to 450 MW.

In May 2006, OPG received a letter from the Minister of Energy, which directed OPG to proceed immediately with the definition phase for a 450 MW development which includes the replacement of the Smoky Falls generating station and the expansion of Little Long, Harmon and Kipling generating stations, all of which are located on the Lower Mattagami River. OPG was also directed to initiate discussions with Ministry staff on a power purchase agreement.

During the latter part of 2006, OPG was engaged in consultations with the First Nations stakeholders, identification of EA requirements, discussions with Hydro One regarding transmission upgrades, and detailing the technical specifications of the project. In addition, OPG received and is reviewing pre-qualification documents from three design/build proponents as well as from four water-to-wire suppliers for the supply and installation of the required generating equipment for the project.

Portlands Energy Centre

OPG entered into a partnership with TransCanada Energy Ltd. ("TransCanada"), through Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle station on the site of the former R.L. Hearn generating station, near downtown Toronto. OPG has a 50 per cent ownership interest in the joint venture.

During the first quarter of 2006, the Province directed the OPA to negotiate an agreement with PEC for the purchase of electricity. PEC signed a 20-year Accelerated Clean Energy Supply ("ACES") contract with the OPA during the third quarter of 2006. PEC entered into an engineer-procure-construct ("EPC") contract to construct the facility, and construction started in 2006. PEC is expected to be operational in simple cycle mode with a capacity of up to 340 MW to meet peak summer demand beginning June 1, 2008. The plant is expected to be completed and fully operational in the second quarter of 2009, providing up to 550 MW of power in combined cycle mode. The capital cost of PEC is estimated to be $730 million excluding capitalized interest. A significant proportion of this capital cost relates to the EPC contract.

OPG's share of capital project expenditures for the year ended December 31, 2006 was approximately $97 million. OPG has negotiated financing for its share of the project with the OEFC.

Lakeview Site

OPG is continuing with decommissioning and demolition of the Lakeview coal-fired generating station, having closed the station in 2005 after more than 40 years of service. OPG is exploring the potential development of a gas-fuelled electricity generating station at the site. The construction of a new plant would proceed only after required approvals and completion of a power purchase agreement.

New Nuclear Generating Units

As directed by the Minister of Energy in June of 2006, OPG initiated a federal approvals process with the CNSC in September of 2006 by filing with the CNSC an Application for a Site Preparation Licence for new nuclear generating units at OPG's Darlington nuclear generating site. The CNSC will review OPG's application and will determine the EA requirements.

Achieving Financial Sustainability

With respect to its strategic financial objectives, OPG's mandate, as agreed with its Shareholder, states that: as an Ontario Business Corporations Act 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. In addition, as a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to or directed by the Shareholder, may receive financial support from the Province, if and as appropriate.

OPG's financial priority, operating as a commercial enterprise, is to achieve a sustainable level of financial performance. Inherent in this priority is the objective of ensuring that sufficient funds are available to achieve OPG's strategic objectives of improving the performance of its generating assets and increasing its generating capacity.

OPG has employed a number of strategies to achieve a level of sustainable financial performance, while maximizing funds from operations. OPG's ability to increase its revenues is constrained as it receives regulated prices for electricity produced from its nuclear generating stations and most of its baseload hydroelectric generating stations, and the majority of the output from its other generating assets is subject to a revenue limit. In light of this constraint, OPG is focused on implementing effective cost management initiatives that include optimizing the management of available resources and identifying and implementing cost reduction programs. These initiatives will be balanced with additional investments required to continue to improve the performance and reliability of OPG's aging generation assets.

To the extent that additional funds, beyond those generated from operations, are required to achieve its strategic objectives of improving the performance of its generating assets and increasing its generating capacity, OPG plans to continue to seek opportunities to diversify its sources of funding and increase its access to cost effective capital. As a result of forecast liquidity constraints in 2007, OPG is in discussions with its Shareholder regarding options to ensure that adequate financing resources are available to fund on-going operational requirements and new generation development. By ensuring access to cost effective funding and maintaining its investment grade credit ratings, OPG will ensure its status as a long term, commercially viable investment.

Excellence in Corporate Governance, Safety, Social Responsibility, Corporate Citizenship and Environmental Stewardship

Another of OPG's strategic objectives within its mandate is to operate in accordance with the highest corporate standards, including, but not limited to, the areas of corporate governance, safety, and sustainable development.

Corporate Governance

OPG's Board of Directors is made up of individuals with substantial expertise in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board has established a number of committees to focus on areas critical to the success of the Company.

OPG's corporate governance strategy is to continually improve the policies and procedures used to direct and manage the corporation to enhance shareholder value and ensure financial viability. OPG continues to implement initiatives to enhance corporate governance practices in line with existing Ontario Securities Commission ("OSC") regulatory requirements, with the objective of strengthening the organization. These initiatives are described in the Corporate Governance section on pages 50 to 56.

Safety

OPG is committed to achieving excellent safety performance and striving for continuous improvement with the goal of minimizing injuries. A primary objective is to achieve excellence in employee and public safety through the development and implementation of formal safety management systems, targeted risk mitigation programs, and a corporate commitment to safety. Continuous oversight and reporting provide management with information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. Oversight activities include internal and external safety management system audits, work protection code audits, and specific operational safety risk reviews. OPG also has a rigorous incident management system, which requires that all incidents, including near misses, be reported and investigated, and that corrective action plans are developed to prevent reoccurrences.

A contractor management program ensures that contractors contribute to OPG's strong safety culture and maintain a level of safety equivalent to that of OPG employees. Initiatives have been implemented to address young worker safety issues within OPG and in the communities where we operate. A commitment to public safety is an important part of the operation of its generating stations, including standards established in the area of public waterways safety.

OPG measures its safety performance primarily through two performance indicators – Accident Severity Rate ("ASR") and All Injury Rate ("AIR"). The ASR is a measure of the number of days lost due to injuries. In 2006, OPG experienced 5.87 days lost per 200,000 hours worked compared to 2.03 in 2005. Although the number of worker injuries was similar to that of 2005, the injuries were more severe, requiring an increase in recuperation days required prior to the employees returning to work. The AIR provides a measure of the frequency of injuries resulting in lost time or requiring medical treatment. In 2006, OPG experienced 1.30 injuries per 200,000 hours worked compared to 1.33 in 2005.

Sustainable Development
OPG's objective is to become a sustainable development company by balancing financial growth, social responsibility and environmental leadership. OPG is committed to minimizing its impact on the environment; operating its facilities safely, reliably and responsibly; and being an engaged and productive member of its host communities. OPG's sustainable development activities can be divided into two categories: Environmental Stewardship, and Social and Corporate Responsibility.

Environmental Stewardship

OPG's Environmental Policy states that "OPG will strive to continually improve its environmental performance" and that the Environmental Policy is an important part of OPG's commitment to Sustainable Development. This policy further 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 ("EMSs") at its generating facilities consistent with the ISO 14001 standard. More information on OPG's emissions into the environment and compliance with environmental laws is included within the *Risk Management – Environmental Risk* section.

OPG utilizes a number of performance indicators to monitor environmental performance, including sulphur dioxide ("SO_2") and nitrogen oxides ("NO_X"). Acid gas (SO_2 and NO_X) emissions were 118 gigagrams (Gg) in 2006 compared to 153 Gg in 2005. The reduction in emissions was primarily a result of lower fossil production in 2006 primarily due to lower Ontario electricity demand, improved performance from the selective catalytic reduction equipment installed at OPG's Nanticoke and Lambton fossil-fuelled generation stations and the use of lower sulphur fuels at OPG's fossil-fuelled stations.

Social and Corporate Responsibility

Contributing to the quality of life in communities where companies operate is a corporate responsibility as well as a societal expectation. OPG is committed to being an active and good corporate citizen by strengthening relationships with the communities that host OPG's generating facilities. At the corporate level, as well as through the actions of employees, OPG plays a significant role in local communities by donating time and resources. OPG's Corporate Citizenship Program provides financial and in-kind support to registered charities and not-for-profit environmental, educational and community organizations whose initiatives reflect OPG's values. Employees donate funds through an annual charity campaign and their time, expertise and energy through numerous personal acts of volunteerism.

OPG is committed to openness and transparency in its reporting to the broader community. This includes operational and financial reports that are prepared in a manner that users can easily understand and distributed in a timely manner.

Capability to Deliver Results

Liquidity and Capital Resources

OPG's financial condition remained stable throughout 2006 following implementation of the regulatory changes which were introduced in 2005. During the year, OPG repaid $806 million of its maturing long-term debt. In addition, new committed debt financing was secured for OPG's interest in the Portlands Energy Centre and Lac Seul generating station projects from the OEFC in the form of long-term debt, on commercial terms and rates.

Liquidity requirements are primarily supported by a bank syndicated credit facility under which OPG issues commercial paper to fund its short-term requirements, and a number of financing arrangements held with the OEFC. As a result of forecast liquidity constraints in 2007, OPG is in discussions with its Shareholder and the OEFC regarding options to ensure that adequate financing resources are available to fund ongoing operational requirements and new generation development.

Generating Assets

OPG has increased the productive capacity of its hydroelectric stations, extended their service lives and invested significant capital for the replacement of aging equipment, upgrades to runners and station automation, and enhanced maintenance practices. Programs are in place to further improve the hydroelectric stations, which already operate with high efficiency and availability.

OPG continues to implement initiatives to improve the reliability and predictability of each of the nuclear generating stations. These initiatives are designed to address the specific technology requirements and risks at each of OPG's nuclear generating stations. The Darlington nuclear generating station is the most recently constructed station in OPG's nuclear fleet and operates with the highest reliability. The two operating units at the Pickering A nuclear generating station have recently been refurbished and are in good material condition. Programs are underway at the Pickering B nuclear generating station to mitigate technological risks and to improve its condition and performance.

OPG will continue to maintain the reliability and productive capacity of its coal-fired generating stations until their scheduled closure dates.

OPG has a number of potential sites for new generating asset development in Ontario. The completion of the decommissioning activity at OPG's Lakeview generating station will provide a brownfield site with the potential for development of additional generating capacity in the Greater Toronto Area.

In addition to the discussion in this section, OPG's capability to deliver results is affected by factors discussed in the *Risk Management* section.

Skilled Workforce

As of December 31, 2006, OPG had approximately 11,500 regular employees. OPG has considerable experience in operating and maintaining generating stations through its trained and qualified technical employees. Due to an aging workforce, OPG's challenge is to attract and retain a skilled workforce to replace retiring employees. Approximately 35 per cent of OPG's workforce was over the age of 50 at December 31, 2006. OPG has initiated a comprehensive resource and succession planning program to address demographic issues related to a high percentage of employees that are eligible for retirement over the next five years, as well as those staffing issues associated with the closure of the coal-fired generating stations.

The Company's collective agreement with the Power Workers' Union runs through March 31, 2009 and the labour agreement with The Society of Energy Professionals runs through December 31, 2010. As of December 31, 2006, the Company had approximately 90 per cent of its regular labour force represented by collective bargaining agreements.

Ontario Electricity Market Trends

Ontario's IESO reported that energy consumed in Ontario was 151 TWh in 2006, which represented a decrease of 3.8 per cent from 157 TWh consumed in 2005. OPG's electricity generating facilities produced 70 per cent of Ontario's 2006 electricity consumption. The combination of increased electricity supply and lower electricity demand in Ontario during 2006 contributed to the lowest annual weighted average hourly Ontario spot electricity market price since the electricity market opened in 2002. The weighted average price for 2006 was 4.9 ¢/kWh, which was a decrease of over 30 per cent when compared to 7.2 ¢/kWh in 2005.

Ontario set a new all-time record for electricity demand of 27,005 MW on August 1, 2006. This record demand exceeded the previous peak set in 2005 of 26,160 MW. However, despite the record peak in 2006, total electricity consumed declined in 2006 compared to 2005. The IESO reported that Ontario's nuclear generating facilities increased their output by three per cent to 84 TWh and provided 54 per cent of Ontario's electricity supply. Hydroelectric generating production remained steady at 22 per cent, or 35 TWh. Electricity generation from coal-fired generating facilities declined three per cent from 2005, which represented 16 per cent of all Ontario electricity generation or 25 TWh. Other fuels, including oil, gas and alternative sources, supplied the remaining eight per cent of Ontario's electricity consumption.

In the IESO's 18-Month Outlook published on December 21, 2006, the IESO indicated that Ontario's existing installed electricity generating capacity was 31,189 MW, an increase of 558 MW when compared to 2005. OPG's in-service electricity generating capacity at the end of 2006 was 22,147 MW or 71 per cent of Ontario's capacity. The expected peak electricity demand in the summer of 2007, under normal weather conditions, is forecast to be 25,658 MW. The IESO reported that over the next 18 months, the outlook for Ontario's supply/demand balance remains positive as a result of a combination of an additional 1,000 MW of electricity generating capacity and a lower forecast for growth in energy consumption and peak electricity demand. New electricity supply includes two gas-fired electricity generating facilities that will contribute to maintaining reliability in and around the Greater Toronto Area. Phase One of the Goreway Station natural gas-fired electricity generating facility is expected to come into service before the summer of 2007, and Phase One of the Portlands Energy Centre is planned to come into service before the summer of 2008.

The IESO's forecast of energy consumption in 2007 is 155 TWh, which represents an increase of approximately 2.5 per cent over consumption in 2006. Significantly lower average electricity sales prices in 2006 had a material impact on OPG's revenues. Electricity prices are forecast to not materially increase in 2007 compared to 2006.

Fuel prices can have a significant impact on revenue and gross margin, both in terms of the underlying commodity price and the United States dollar ("USD") to Canadian dollar exchange rate. During 2006, spot prices for Appalachian and Powder River Basin coal, natural gas, and oil experienced slight decreases to modest increases. OPG has a fuel hedging program, which includes fixed price and indexed contracts for fossil and nuclear fuels, as well as commodity derivatives. Foreign exchange derivatives are used to manage exposure to anticipated USD denominated purchases.

In March 2007, Ontario's Integrated Power System Plan ("IPSP"), being prepared by the OPA, will be submitted to the OEB for their review and approval. The plan will identify the conservation, generation, and transmission investments that are needed in the next three to five years, indicate the preparatory work required for the subsequent five years, and chart broad directions for the development of the electricity system for the balance of the planning period.

Business Segments

Prior to the introduction of rate regulation, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, included revenue and certain costs not allocated to its business segments.

With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Beginning in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods were reclassified to reflect the revised disclosure.

OPG has entered into various energy and related sales contracts with its customers to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included with electricity production revenues in each segment up to March 31, 2005, and in the Unregulated – Hydroelectric and Unregulated – Fossil-Fuelled generation segments after that date. Gains or losses in these hedging transactions are recognized in revenue over the terms of the contract when the underlying transaction occurs.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This arrangement includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of its baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – Hydroelectric business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support and automatic generation control, and revenues from other services.

Other

The Other category includes revenue that OPG earns from its 50 per cent joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses. In addition, the Other category includes revenue from real estate rentals.

Key Generation and Financial Performance Indicators

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, and environmental performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology. These indicators are defined in this section and are discussed in the *Discussion of Operating Results by Business Segment* section.

Nuclear Unit Capability Factor

OPG's nuclear stations operate as baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability.

Fossil-Fuelled and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's fossil-fuelled stations provide a flexible source of energy and operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations. OPG's hydroelectric stations operate primarily as baseload facilities and provide a reliable and low-cost source of renewable energy. A key measure of the reliability of the fossil-fuelled and hydroelectric stations is their ability to be available to produce electricity when called upon. EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Hydroelectric Availability

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and the disposal of low and intermediate level radioactive waste materials, divided by total energy produced.

Hydroelectric OM&A Expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses, including allocated corporate costs, divided by hydroelectric electricity generation.

Fossil-Fuelled OM&A Expense per MW

Since fossil-fuelled generating stations are primarily employed during periods of intermediate and peak demand, the cost effectiveness of these stations is measured by their total OM&A expenses, including allocated corporate costs, divided by total station nameplate capacity.

Other Key Indicators

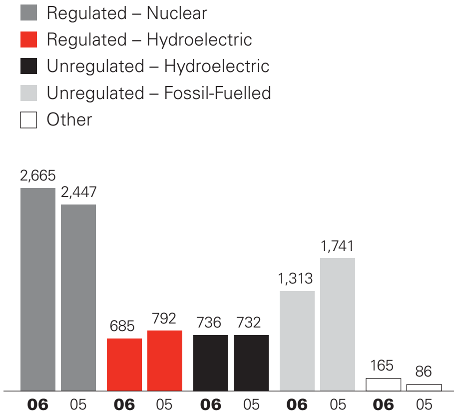
In addition to performance and cost effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, Risk Management.

Discussion of Operating Results by Business Segment

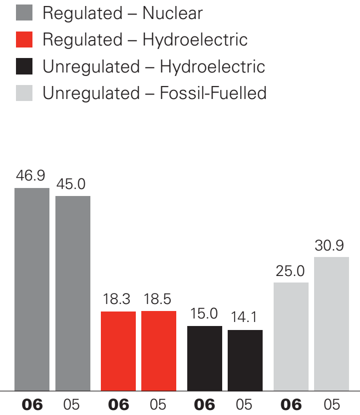
This section summarizes OPG's key results by segment for the years ended December 31, 2006 and 2005. Although the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) became effective commencing April 1, 2005, results for the entire 2005 year were reclassified according to the business segment definitions. The operating results for the first quarter of 2005 prior to rate regulation reflect a significantly different economic environment from that introduced by rate regulation.

Years Ended December 31

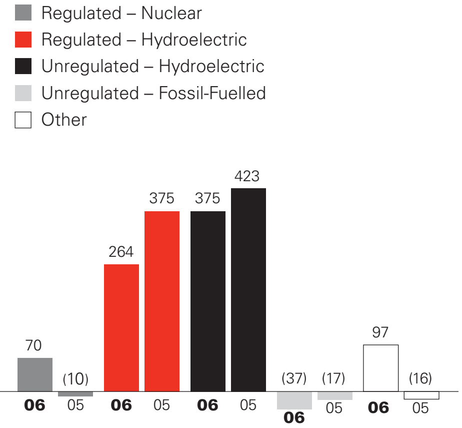
Revenue, Net of Revenue Limit and Market Power Mitigation Agreement Rebates
(millions of dollars)



Electricity Production
(TWh)



Income (Loss) Before Interest, Income Taxes and Extraordinary Item
(millions of dollars)



The following table provides a summary of revenue, earnings and key generation and financial performance indicators by business segment:

(millions of dollars)	2006	2005
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates		
Regulated – Nuclear	**2,665**	2,447
Regulated – Hydroelectric	**685**	792
Unregulated – Hydroelectric	**736**	732
Unregulated – Fossil-Fuelled	**1,313**	1,741
Other	**165**	86
	5,564	5,798
Income (loss) before interest, income taxes and extraordinary item		
Regulated – Nuclear	**70**	(10)
Regulated – Hydroelectric	**264**	375
Unregulated – Hydroelectric	**375**	423
Unregulated – Fossil-Fuelled	**(37)**	(17)
Other	**97**	(16)
	769	755
Electricity Generation (TWh)		
Regulated – Nuclear	**46.9**	45.0
Regulated – Hydroelectric	**18.3**	18.5
Unregulated – Hydroelectric	**15.0**	14.1
Unregulated – Fossil-Fuelled	**25.0**	30.9
Total electricity generation	**105.2**	108.5
Nuclear unit capability factor (per cent)		
Darlington	**88.7**	90.6
Pickering A	**72.0**	69.9
Pickering B	**75.2**	77.7
Equivalent forced outage rate (per cent)		
Regulated – Hydroelectric	**1.5**	1.2
Unregulated – Hydroelectric	**1.9**	1.4
Unregulated – Fossil-Fuelled	**14.1**	15.9
Availability (per cent)		
Regulated – Hydroelectric	**94.2**	92.7
Unregulated – Hydroelectric	**92.4**	92.2
Nuclear PUEC ($/MWh)	**42.87**	40.24
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**5.01**	4.23
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**12.63**	10.55
Unregulated – Fossil-Fuelled OM&A expense per MW ($000/MW)	**61.1**	53.0

Regulated – Nuclear Segment

(millions of dollars)	2006	2005
Revenue net of Market Power Mitigation Agreement rebate	**2,665**	2,447
Fuel expense	**122**	115
Gross margin	**2,543**	2,332
Operations, maintenance and administration	**1,967**	1,804
Depreciation and amortization	**343**	359
Accretion on fixed asset removal and nuclear waste management liabilities	**490**	467
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(371)**	(381)
Property and capital taxes	**44**	30
Income before impairment of long-lived assets	**70**	53
Impairment of long-lived assets	**–**	63
Income (loss) before interest and income taxes	**70**	(10)

Revenue

(millions of dollars)	2006	2005
Regulated generation sales	**2,312**	1,621
Spot market sales, net of hedging instruments	**–**	662
Market Power Mitigation Agreement rebate	**–**	(160)
Variance account	**1**	(1)
Other	**352**	325
Total revenue	**2,665**	2,447

Regulated – Nuclear revenue was $2,665 million for the year ended December 31, 2006 compared to $2,447 million in 2005. The increase in revenue was primarily due to higher electricity generation of 1.9 TWh in 2006 compared to 2005, and higher sales prices related to the introduction of regulated prices effective April 1, 2005.

Electricity Prices

Electricity generation from stations in the Regulated – Nuclear segment have received a fixed price of 4.95¢/kWh since the introduction of rate regulation effective April 1, 2005. For the year ended December 31, 2005, OPG's Regulated – Nuclear sales price was 4.7¢/kWh, after taking into account the regulated price for the last three quarters of 2005, and the spot market sales price, net of the Market Power Mitigation Agreement rebate for the first quarter of 2005.

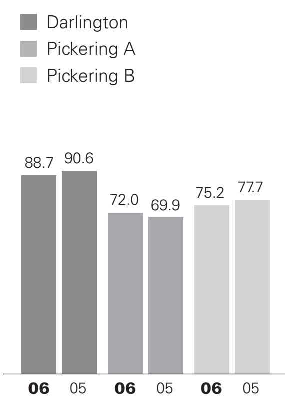
Volume

Electricity generation from stations in the Regulated – Nuclear segment for the year ended December 31, 2006 was 46.9 TWh compared to 45.0 TWh in 2005. The increase in volume was mainly due to the return to service of Unit 1 at the Pickering A nuclear generating station in the fourth quarter of 2005. Also, in the second quarter of 2005, Unit 4 at the Pickering A nuclear generating station was shut down for the duration of the quarter due to the inspection and repair of feeder pipes. Electricity generation from the Darlington and Pickering B nuclear generating stations decreased in 2006 compared to 2005 due to an increase in unplanned outage days.

The Darlington nuclear generating station's unit capability factor for the year ended December 31, 2006 was 88.7 per cent compared to 90.6 per cent in 2005. The decrease was a result of higher unplanned outage days in 2006.

Years Ended December 31

Nuclear Unit Capability Factor
(%)



Nuclear PUEC
($/MWh)

The Pickering A nuclear generating station's unit capability factor improved to 72.0 per cent for the year ended December 31, 2006 compared to 69.9 per cent in 2005. The increase was primarily due to lower unplanned outage days in 2006 compared to 2005, related to the shutdown of Unit 4 in 2005 for feeder inspection and repair.

The Pickering B nuclear generating station's unit capability factor was 75.2 per cent compared to 77.7 per cent in 2005. The decrease was primarily due to an increase in unplanned outage days in 2006 compared to 2005.

Fuel Expense

Fuel expense for the year ended December 31, 2006 was $122 million compared to $115 million in 2005. Fuel expense was moderately affected by incremental nuclear generation in 2006 compared to 2005, due to the low marginal cost of nuclear generation.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2006 were $1,967 million compared to $1,804 million in 2005. The increase of $163 million in OM&A expenses in 2006 compared to 2005 was primarily due to higher pension and OPEB costs of $133 million mainly due to changes in economic assumptions and higher costs of $62 million related to nuclear outages and projects to improve the performance of the nuclear generating stations. In addition, OM&A expenses for the year ended December 31, 2006 included amortization of $25 million related to Pickering A nuclear generating station return to service costs, which were previously deferred. In 2005, OM&A expenses were affected by a write-off of excess inventory of $57 million acquired for the anticipated return to service of Units 2 and 3 at the Pickering A nuclear generating station.

Effective January 1, 2005, in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), OPG established a balance sheet deferral account for non-capital costs associated with the planned return to service of all units at the Pickering A nuclear generating station. The deferred costs are charged to operations in accordance with the terms of the regulation. Amortization of this deferral account commenced in the fourth quarter of 2005 following the return to commercial service of Unit 1 of the Pickering A nuclear generating station.

Nuclear PUEC increased to $42.87/MWh for 2006 compared to $40.24/MWh during 2005. The increase during the year ended December 31, 2006 was mainly due to higher pension and OPEB costs of $133 million, and other changes in OM&A expenses, partially offset by higher generation in 2006 compared.

Depreciation and Amortization

Depreciation and amortization expense for the year ended December 31, 2006 was $343 million compared to $359 million in 2005. The decrease was primarily due to the impact of an extension of the remaining service lives of the Pickering B nuclear generating station and Unit 4 of the Pickering A nuclear generating station, for purposes of calculating depreciation. The reduction in depreciation related to the service life extension was partially offset by the impact of the return to commercial service of Unit 1 at the Pickering A station and fixed asset additions.

Accretion

Accretion expense relating to future costs for fixed asset removal and nuclear waste management was $490 million for the year ended December 31, 2006 compared to $467 million in 2005. The increase in the accretion expense in 2006 was due to the higher liability balance compared to last year primarily as a result of the increase in the present value of the liability due to the passage of time.

Earnings on the Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG realized earnings of $371 million on the nuclear fixed asset removal and nuclear waste management funds in 2006, compared to $381 million in 2005. The decrease was due primarily to the impact of a lower Ontario Consumer Price Index on the Used Fuel Segregated Fund ("Used Fuel Fund") earnings when compared to 2005, and a decrease in earnings from the Decommissioning Segregated Fund ("Decommissioning Fund"). Used Fuel Fund earnings are guaranteed by the Province at 3.25 per cent plus the change in the Ontario Consumer Price Index. The decrease was partially offset by the effect of an increase in earnings as a result of a higher asset base in 2006. Starting January 1, 2007, the recognition of earnings on the nuclear fixed asset removal and nuclear waste management funds are affected by the adoption of new Canadian Institute of Chartered Accountants ("CICA") handbook sections as described under the heading *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds* in the *Balance Sheet Highlights* section.

Impairment of Long-Lived Assets

During the second quarter of 2005, OPG completed an assessment of the scope of the refurbishment work, the cost and the risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. OPG's Board of Directors decided that, while technically feasible, the return to service of these units was not justified on a commercial basis. As a result, the Company recorded an impairment loss of $63 million related to the carrying amount of these two units, including construction in progress.

Regulated – Hydroelectric Segment

(millions of dollars)	2006	2005
Revenue, net of Market Power Mitigation Agreement rebate	**685**	792
Fuel expense	**245**	254
Gross margin	**440**	538
Operations, maintenance and administration	**92**	78
Depreciation and amortization	**66**	67
Property and capital taxes	**18**	18
Income before interest and income taxes	**264**	375

Revenue

(millions of dollars)	2006	2005
Regulated generation sales[1]	**635**	558
Spot market sales, net of hedging instruments	**–**	260
Market Power Mitigation Agreement rebate	**–**	(65)
Variance accounts	**(4)**	2
Other	**54**	37
Total revenue	**685**	792

1 Regulated generation sales included revenue of $169 million and $210 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the year ended December 31, 2006 and 2005, respectively.

Regulated – Hydroelectric revenue was $685 million for the year ended December 31, 2006 compared to $792 million in 2005. The decrease in revenue was mainly due to lower sales prices related to the introduction of regulated prices effective April 1, 2005, lower average spot market prices during 2006 compared to 2005 that affected revenues in excess of 1,900 MWh in any hour, and lower sales volume in 2006 compared to 2005.

Electricity Prices
The average price for the year ended December 31, 2006 was 3.5¢/kWh compared to 4.1¢/kWh in 2005. The average price in 2005 reflected the regulated price for the last three quarters of 2005 and OPG's average spot market sales price net of the Market Power Mitigation Agreement rebate for the first quarter of 2005.

Volume
Electricity sales volume for the year ended December 31, 2006 decreased to 18.3 TWh compared to 18.5 TWh in 2005. During 2006, electricity generation of 3.4 TWh related to production levels above 1,900 MWh in any hour. For 2005, electricity generation of 2.8 TWh related to production levels above 1,900 MWh in any hour during the last three quarters of 2005. The decrease in electricity sales volume in 2006 compared to 2005 was primarily due to lower water levels.

The equivalent forced outage rate for the Regulated – Hydroelectric stations was 1.5 per cent for the year ended December 31, 2006 compared to 1.2 per cent in 2005.

The availability for the Regulated – Hydroelectric stations was 94.2 per cent for the year ended December 31, 2006 compared to 92.7 per cent in 2005. The high availability and low equivalent forced outage rate reflect the continuing strong performance of these generating stations.

Variance Accounts
OPG is required, under a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), to establish variance accounts to capture the impact of differences in hydroelectric electricity production due to differences

Years Ended December 31

Regulated – Hydroelectric EFOR
(%)

Regulated – Hydroelectric Availability
(%)

Regulated – Hydroelectric OM&A per MWh
($/MWh)

between forecast and actual water conditions and differences between assumed and actual revenues for ancillary services. During 2006, OPG recorded a reduction in revenue of $4 million, reflecting ancillary services revenue that was favourable compared to the forecast for 2006 provided to the Province for the purposes of establishing regulated prices.

Fuel Expense

OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense. Fuel expense for the year ended December 31, 2006 was $245 million compared to $254 million in 2005. The decrease in fuel expense was due to lower generation and lower marginal GRC rates as a result of lower generation from rate regulated hydroelectric stations.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2006 were $92 million compared to $78 million in 2005. The increase in OM&A expenses in 2006 was primarily due to higher pension and OPEB costs.

OM&A expense per MWh for the regulated hydroelectric stations increased to $5.01/MWh in 2006 compared to $4.23/MWh in 2005. The increase in 2006 compared to 2005 mainly reflected higher OM&A expenses combined with lower generation.

Depreciation and Amortization

Depreciation expense for the year ended December 31, 2006 was $66 million compared to $67 million in 2005.

Unregulated – Hydroelectric Segment

(millions of dollars)	**2006**	2005
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**736**	732
Fuel expense	**88**	82
Gross margin	**648**	650
Operations, maintenance and administration	**189**	148
Depreciation and amortization	**69**	64
Property and capital taxes	**15**	15
Income before interest and income taxes	**375**	423

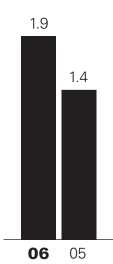
Revenue

(millions of dollars)	**2006**	2005
Spot market sales, net of hedging instruments	**746**	962
Revenue limit rebate	**(44)**	(210)
Market Power Mitigation Agreement rebate	**–**	(58)
Other	**34**	38
Total revenue	**736**	732

Unregulated – Hydroelectric revenue was $736 million for the year ended 2006 compared to $732 million in 2005. The marginal increase was due to higher electricity generation of 0.9 TWh, largely offset by the impact of lower Ontario spot market prices during 2006 compared to 2005.

Years Ended December 31

Unregulated – Hydroelectric EFOR
(%)



Unregulated – Hydroelectric Availability
(%)

Unregulated – Hydroelectric OM&A per MWh
($/MWh)

Electricity Prices
Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, was subject to the revenue limit based on an average price of 4.7¢/kWh commencing April 1, 2005. Effective May 1, 2006, the revenue limit decreased to 4.6¢/kWh.

OPG's average sales price for its unregulated hydroelectric generation for the year ended December 31, 2006 was 4.6¢/kWh compared to 5.2¢/kWh in 2005. The decrease was primarily due to lower average Ontario spot market prices, partly offset by the favourable impact of the replacement of the Market Power Mitigation Agreement rebate with the revenue limit rebate effective April 1, 2005.

Volume
Electricity sales volume for the year ended December 31, 2006 was 15.0 TWh compared to 14.1 TWh in 2005. The increase in volume in 2006 was primarily due to higher water levels in Eastern Ontario during 2006 compared to 2005.

The equivalent forced outage rate for the Unregulated – Hydroelectric stations was 1.9 per cent for the year ended December 31, 2006 compared to 1.4 per cent during the same period in 2005. The increase in EFOR was due to equipment repairs and forced outages at certain stations.

The availability for the Unregulated – Hydroelectric stations was 92.4 per cent for the year ended December 31, 2006 compared to 92.2 per cent for the year ended December 31, 2005. The availability and the equivalent forced outage rate during 2006 continue to reflect the strong performance of the unregulated hydroelectric generating assets.

Fuel Expense
Fuel expense was $88 million for the year ended December 31, 2006, compared to $82 million in 2005. The increase in fuel expense was primarily due to higher electricity generation. Generating stations within this segment are subject to the GRC.

Operations, Maintenance and Administration
OM&A expenses for the year ended December 31, 2006 were $189 million compared to $148 million in 2005. The increase in OM&A expense in 2006 was primarily due to higher expenses for plant improvement projects and higher pension and OPEB costs.

OM&A expense per MWh for the unregulated hydroelectric stations increased to $12.63/MWh for the year ended December 31, 2006 from $10.55/MWh in 2005. The increases in 2006 compared to 2005 reflect higher OM&A expenses, partially offset by higher generation.

Depreciation and Amortization
Depreciation expense for the year ended December 31, 2006 was $69 million compared to $64 million in 2005.

Unregulated – Fossil-Fuelled Segment

(millions of dollars)	**2006**	2005
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**1,313**	1,741
Fuel expense	**643**	846
Gross margin	**670**	895
Operations, maintenance and administration	**524**	455
Depreciation and amortization	**133**	203
Accretion on fixed asset removal	**9**	9
Property and capital taxes	**19**	39
Restructuring	**–**	4
(Loss) income before impairment of long-lived assets	**(15)**	185
Impairment of long-lived assets	**22**	202
Loss before interest and income taxes	**(37)**	(17)

Revenue

(millions of dollars)	**2006**	2005
Spot market sales, net of hedging instruments	**1,323**	2,293
Revenue limit rebate	**(117)**	(529)
Market Power Mitigation Agreement rebate	**–**	(129)
Other	**107**	106
Total revenue	**1,313**	1,741

Unregulated – Fossil-Fuelled revenue was $1,313 million for the year ended December 31, 2006, a decrease of $428 million compared to $1,741 million in 2005. The decrease in revenue in 2006 compared to 2005 was primarily due to lower electricity generation of 5.9 TWh in 2006 and lower average sales prices when compared to 2005. These impacts were partially offset by revenue from the Lennox RMR contract. The RMR contract, which commenced effective October 1, 2005, is a one year cost-based contract with the IESO that provides for regular payments, which are subject to adjustments for actual costs. OPG and the IESO negotiated an agreement in July 2006 for a subsequent one year cost-based contract. This agreement was approved in January 2007 by the OEB.

Electricity Prices
OPG's average sales price for its unregulated fossil-fuelled generation for the year ended December 31, 2006 was 4.8¢/kWh compared to 5.5¢/kWh in 2005. The decrease was primarily due to lower average Ontario spot market prices in 2006, partially offset by the favourable impact of the replacement of the Market Power Mitigation Agreement rebate with the revenue limit rebate effective April 1, 2005.

Volume
Electricity sales volume decreased to 25.0 TWh compared to 30.9 TWh in 2005. The decrease of 5.9 TWh was primarily due to lower overall electricity market demand in Ontario and higher nuclear generation.

The equivalent forced outage rate for the fossil-fuelled generating stations was 14.1 per cent for the year ended December 31, 2006 compared to 15.9 per cent in 2005. EFOR decreased in 2006 primarily due to the impact of closing the Lakeview generating station in April 2005 and improved equipment reliability of the fossil-fuelled generating stations.

Fuel Expense
Fuel expense decreased to $643 million for the year ended December 31, 2006 compared to $846 million in 2005. The decrease of $203 million in 2006 compared to 2005 was due to lower generation and a higher blend of lower cost Powder River Basin coal at the Nanticoke fossil-fuelled generating station, partly offset by higher average coal prices.

Operations, Maintenance and Administration
OM&A expenses for the year ended December 31, 2006 were $524 million compared to $455 million in 2005. OM&A expenses increased in 2006 mainly due to higher pension and OPEB costs, the write-off of unrecoverable costs related to the Thunder Bay generating station gas conversion project, and higher expenditures on maintenance for the Nanticoke and Lambton generating stations.

OM&A expense per MW ($/MW) for the unregulated fossil-fuelled stations increased to $61,100/MW for the year ended December 31, 2006 compared to $53,000/MW in 2005. The increase in 2006 reflected higher OM&A expenses, and the impact of lower generation capacity due to the closure of the Lakeview generating station in April 2005.

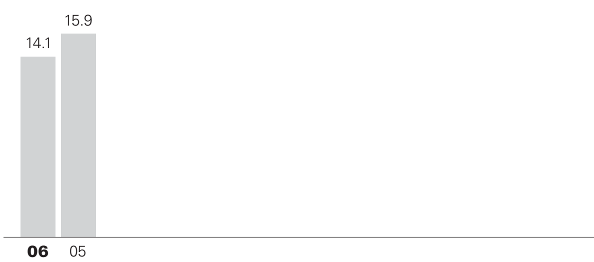
Depreciation and Amortization
Depreciation expense for the year ended December 31, 2006 was $133 million compared to $203 million in 2005. The decrease in depreciation expense in 2006 was mainly due to the extension of the service life of all coal-fired generating stations, for purposes of calculating depreciation, due to the delay in the Province's coal replacement program. Furthermore, depreciation expense decreased due to a lower asset base, which resulted from the impairment charge on the Lennox generating station, which was recorded in 2005.

In the third quarter of 2005, OPG had extended, for purposes of calculating depreciation, the remaining service life of the Nanticoke generating station by one year, from 2007 to 2008, based on further details provided by the Province with respect to its coal replacement program at that time. The estimated service life for all of the coal-fired generating stations as at June 30, 2006, for purposes of calculating depreciation, was December 31, 2007, with the exception of the Nanticoke generating station. As a result of an announcement in June 2006 of delays in the plan to replace coal-fired generation, OPG extended, effective July 1, 2006, the service life for all of the coal-fired generating stations, for the purpose of calculating depreciation, to December 31, 2012. OPG will continue to assess the service life of the coal-fired stations upon submission of the IPSP, and as subsequently approved by the OEB, and other available information.

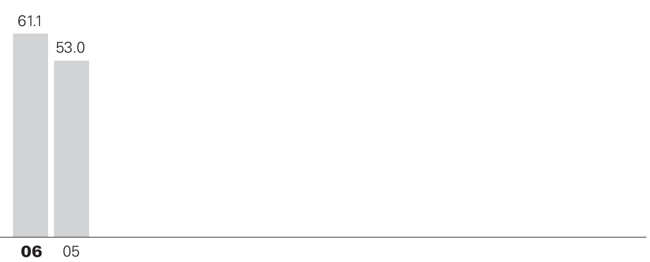
Impairment of Long-Lived Assets
OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations in 2006 of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result

Years Ended December 31

Unregulated – Fossil-Fuelled EFOR
(%)



Unregulated – Fossil-Fuelled OM&A per MW
($000/MWh)



of changes in circumstance, which included a decrease in forecast Ontario spot market prices and the extension of the lives of the coal-fired stations. The fair value of the coal-fired generating stations, which was determined using a discounted cash flow method, was compared to the carrying value of the generating assets to determine the impairment loss. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives.

In 2005, OPG recorded an impairment charge of $202 million, which was the carrying value of the Lennox generating station. OPG was advised by the Province that it would not support an arrangement that would allow for the recovery of costs related to the carrying value of the Lennox generating station.

Other

(millions of dollars)	**2006**	2005
Revenue	**165**	86
Operations, maintenance and administration	**5**	31
Depreciation and amortization	**53**	60
Property and capital taxes	**10**	5
Restructuring	**–**	6
Income (loss) before interest and income taxes	**97**	(16)

Other revenue for the year ended December 31, 2006 was $165 million compared to $86 million in 2005. The increase of $79 million was primarily due to revenue from trading activities. During 2006, OPG had an increase in mark-to-market gains on interconnected sales contracts and higher margins on interconnected sales compared to 2005.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment of the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the year ended December 31, 2006, the service fee was $25 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric and $9 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $39 million for the Other category. Results of the 2005 comparative year have been reclassified to reflect the service fee. The decrease in OM&A expenses of the Other category in 2006 compared to 2005 was partly due to reduced activity in the Energy Markets business and an increase in the service fee.

Interconnected purchases and sales (including those to be physically settled) and mark-to-market gains and losses (realized and unrealized) on energy trading contracts are disclosed on a net basis in the consolidated statements of income. If disclosed on a gross basis, revenue and power purchases for the year ended December 31, 2006 would have increased by $163 million (2005 – $228 million), with no impact on net income.

The carrying amounts and notional quantities of derivative instruments not designated for hedging purposes are disclosed in Note 12 in the audited consolidated financial statements as at December 31, 2006.

Income Tax

OPG follows the liability method of tax accounting for its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in future regulated prices charged to customers.

Income tax expense for the year ended December 31, 2006 reflected the impact of accounting for income taxes for the regulated segments of the business using the taxes payable method. Income tax expense for 2005 reflected the impact of the taxes payable method for the last three quarters, as this method was adopted upon inception of the rate regulation on April 1, 2005.

Income tax expense for the year ended December 31, 2006 was $86 million compared to $118 million in 2005. The elimination of the Large Corporations Tax and the reduction in the future income tax rates enacted in 2006 reduced income tax expense in the year. In 2005, OPG recorded an income tax charge of $50 million to provide for a change in income tax liabilities related to certain income tax positions that the Company had taken in prior years. During the years ended December 31, 2006 and 2005, the income tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segment using the liability method by $89 million and $157 million, respectively.

During 2005, as a result of the adoption of the taxes payable method for the rate regulated segments on April 1, 2005, OPG eliminated the net future income tax asset balance of $74 million related to the rate regulated segments and recognized the amount as a one-time extraordinary loss in determining net income.

In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors ("Tax Auditors") with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998*. OPG has estimated that the proposed adjustments could result in additional taxes payable for the 1999 taxation year in excess of $200 million. Although OPG has subsequently resolved some of these issues, there is uncertainty as to how the remaining issues will be resolved.

OPG expects to receive a reassessment for its 1999 taxation year. The Company would defend its position through the tax appeals process. The potential increase in taxes payable related to these issues for 1999 and subsequent taxation years could be material. Because OPG uses the taxes payable method to account for income taxes in the regulated business segments and the liability method for the unregulated business segments, the impact of any potential adjustments on future income tax expense could vary significantly, depending on the resolution of these issues.

OPG has previously recorded income tax charges related to certain income tax positions that the Company has taken in prior years that may be disallowed. Given the uncertainty as to how these income tax matters will be resolved, OPG has not adjusted its income tax liabilities. Should the ultimate outcome materially differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its net income could be affected positively or negatively in the period in which the matters are resolved.

Liquidity and Capital Resources

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, and credit facilities provided by OPG's Shareholder. These resources are required for continued investment in plant and technologies, and to meet other significant funding obligations including contributions to the pension fund, the Used Fuel Fund and Decommissioning Fund (together, the "Nuclear Funds"), and to service and repay long-term debt and revenue limit rebate obligations.

(millions of dollars)	**2006**	2005
Cash and cash equivalents, beginning of the year	**908**	2
Cash flow provided by operating activities	**397**	1,201
Cash flow (used in) investing activities	**(650)**	(760)
Cash flow (used in) provided by financing activities	**(649)**	465
Net (decrease) increase	**(902)**	906
Cash and cash equivalents, end of the year	**6**	908

Operating Activities

Cash flow provided by operating activities for 2006 was $397 million compared to $1,201 million during 2005. The decrease in cash flow from operating activities was primarily due to lower revenue before rebates as a result of lower Ontario spot electricity market prices, partially offset by the impact of lower expenditures on fuel and higher non-energy revenue.

OPG made quarterly revenue limit payments during 2006 of $860 million, of which $739 million relates to the period of April to December, 2005. The revenue limit payments in 2006 contributed to the decrease in the operating cash flows.

Further, the expenditures on fixed asset removal and nuclear waste management for 2006 were $164 million as compared to $90 million in 2005. The increase of $74 million in 2006 was mostly due to increased expenditures relating to the safe storage of Units 2 and 3 at the Pickering A nuclear generating station. OPG is in the process of submitting a request to the Province to approve reimbursements from the Nuclear Funds to cover the expenditures relating to the safe storage program of Units 2 and 3 at the Pickering A nuclear generating station.

Investing Activities

OPG is in a capital-intensive business that requires continued investment in plant and technologies to improve operating efficiencies, increase generating capacity of its existing stations, invest in new generating stations and to maintain and improve service, reliability, safety and environmental performance.

Investment in fixed assets during the year ended December 31, 2006 was $637 million compared with $494 million in 2005. The increase in capital expenditures of $143 million was primarily due to OPG's increased investment in the Niagara Tunnel project, Portlands Energy Centre, the Lac Seul project and the Pickering B nuclear generating station auxiliary power system. The impact of these investments was largely offset by a lower investment at the Pickering A nuclear generating station in 2006 compared to 2005, with the return to service of Unit 1 in November 2005.

OPG's anticipated capital expenditures for 2007 are approximately $1 billion, which include amounts for the Niagara Tunnel project, Portlands Energy Centre, Lac Seul project and the Lower Mattagami project.

Included in the investing activities are increases in OPG's regulatory assets of $13 million for the year ended December 31, 2006 compared to $265 million in 2005. The lower investment in regulatory assets during 2006 was primarily due to the return to service of Unit 1 at the Pickering A nuclear generating station in 2005.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility which is divided into two tranches – a $500 million 364-day term tranche maturing May 22, 2007 and a $500 million three-year term tranche maturing May 22, 2009. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. OPG has recently borrowed under its commercial paper program, and as at December 31, 2006, $15 million of commercial paper was outstanding. OPG had no other outstanding borrowings under the bank credit facility.

OPG also maintains $26 million (2005 – $26 million) in short-term uncommitted overdraft facilities as well as $240 million (2005 – $215 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support the supplementary pension plans, and is required to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At December 31, 2006, there was a total of $185 million (2005 – $157 million) of Letters of Credit issued, which includes $159 million for the supplementary pension plans and $16 million related to the construction of the Portlands Energy Centre.

To finance the Niagara Tunnel project, OPG negotiated an agreement with the OEFC to finance the project for up to $1 billion over the duration of the project. The funding will be advanced in the form of 10-year notes, on commercial terms and conditions. Advances under this facility commenced in October 2006, and amounted to $160 million as at December 31, 2006. Similarly, debt financing has been negotiated with the OEFC for OPG's interest in the Portlands Energy Centre and Lac Seul projects for up to $400 million and $50 million, respectively. Advances under these facilities commenced in December 2006, and totalled $90 million for the Portlands Energy Centre and $20 million for the Lac Seul projects, as at December 31, 2006.

During 2006, OPG's Board of Directors approved the payment of a dividend to its Shareholder, the Province. The declared dividend of $128 million represents 35 per cent of OPG's 2005 net income and was paid in November 2006.

As at December 31, 2006, OPG's long-term debt outstanding with the OEFC was approximately $3.2 billion. Although the new financing added in 2006 has extended the maturity profile, approximately $2.5 billion of long-term debt must be repaid or refinanced within the next five years. OPG's liquidity outlook for 2007 is forecast to be constrained due to electricity prices that are forecast to remain at relatively low levels, revenues that are subject to regulated prices and a revenue limit, increasing pension and other post employment benefit costs, debt repayment obligations, and significant funding requirements for ongoing operations and new generation project development. To ensure that adequate financing resources are available beyond its $1 billion commercial paper program backed by the bank credit facility, OPG is in discussions with its Shareholder and the OEFC regarding a new financial agreement that would provide for longer term financial support.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2006, are as follows:

(millions of dollars)	2007	2008	2009	2010	2011	Thereafter	**Total**
Contractual obligations:							
Fuel supply agreements	670	514	202	153	167	351	**2,057**
Contributions under the ONFA[1]	454	679	350	350	350	1,053	**3,236**
Long-term debt repayment	400	400	350	970	375	670	**3,165**
Interest on long-term debt	181	158	135	103	55	80	**712**
Unconditional purchase obligations	25	20	17	15	12	194	**283**
Long-term accounts payable	28	9	–	–	–	–	**37**
Operating lease obligations	10	9	11	10	10	123	**173**
Operating licence	16	17	17	17	18	–	**85**
Pension contributions[2]	268	–	–	–	–	–	**268**
Other	144	30	26	28	24	26	**278**
Significant commercial commitments:							
Niagara Tunnel	167	178	132	2	–	–	**479**
Lac Seul	24	–	–	–	–	–	**24**
Portlands Energy Centre	155	63	22	2	1	24	**267**
Total	2,542	2,077	1,262	1,650	1,012	2,521	**11,064**

1 Contributions under the ONFA are subject to adjustment due to the 2006 Approved ONFA Reference Plan.

2 The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuation as at January 1, 2005, as well as a voluntary contribution of approximately $20 million. The contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, and the timing of funding valuations. Funding requirements after 2007 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

Credit Ratings

Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access. The cost and availability of financing is influenced by credit ratings, which are intended to be an indicator of the creditworthiness of a particular company, security or obligation. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets.

At December 2006, OPG has a long-term credit rating of BBB+ by Standards & Poor's ('S&P') and 'A (low)' by Dominion Bond Rating Service ("DBRS"). In May 2006, S&P issued a press release expressing their recognition of OPG's improving performance and prospects and announcing that they had upgraded the Company's short-term Canadian scale Commercial Paper debt rating to 'A-1 (low)' from 'A-2'. The outlook on OPG's long-term credit rating is positive. In August 2006, DBRS issued a rating report confirming OPG's long-term debt rating and short-term Commercial Paper rating of 'A (low)' and 'R-1 (low)', respectively, with a stable outlook.

Critical Accounting Policies and Estimates

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the consolidated financial statements as at and for the year ended December 31, 2006. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates and the impact of changes in certain conditions or assumptions, are highlighted on the following page.

Rate Regulated Accounting

A regulation made pursuant to the *Electricity Restructuring Act, 2004* (Ontario) prescribes that most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates receive regulated prices for their output. Under this regulation, OPG is required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005, that are associated with the planned return to service of all units at the Pickering A nuclear generating station. As at December 31, 2006, the deferral account balance was $249 million, consisting of non-capital costs of $232 million related to Unit 1, $19 million related to Units 2 and 3, $20 million of general return to service costs, interest of $7 million applied at the annual rate of six per cent, as prescribed by the regulation, and accumulated amortization of $29 million. As at December 31, 2005, the deferral account balance was $261 million, consisting of non-capital costs of $228 million related to Unit 1, $19 million related to Units 2 and 3, $11 million of general return to service costs, interest of $7 million applied at the annual rate of six per cent, and accumulated amortization of $4 million. OPG commenced the amortization of the deferral account associated with Unit 1 of the Pickering A nuclear generating station when the unit was returned to service in November 2005. The amortization of $25 million was charged to OM&A expense in 2006 (2005 – $4 million). Upon OPG becoming subject to regulated prices established by the OEB, which is expected in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account through future prices charged to customers on a straight-line basis, over a period not to exceed 15 years.

In addition, under the regulation, OPG is required to establish a variance account to record certain costs incurred on or after April 1, 2005, due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices, associated with a number of predefined circumstances. Under the terms of the regulation, the OEB is directed to ensure that OPG either recovers or returns those amounts through future regulated prices charged to customers over a period not to exceed three years, to the extent that the OEB is satisfied that the costs were prudently incurred and are accurately recorded. As at December 31, 2006, the balance was nil (2005 – $5 million) in the variance account related to revenues for ancillary services that were below the forecast provided to the Province for the purposes of establishing regulated prices. As at December 31, 2006 and 2005, OPG recorded a regulatory liability of $4 million in a variance account reflecting water conditions that were favourable to those forecasted. Further, as of December 31, 2006, OPG recorded a regulatory asset of $2 million reflecting lower generation sales caused by transmission outages and transmission restrictions. Other regulatory liability includes a portion of non-regulated revenue earned by OPG's regulated assets, which may result in a reduction of future regulated prices to be established by the OEB. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions including assumptions made in the interpretation of the regulation.

In February 2007 the Province amended the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to clarify certain sections of the regulation and to require OPG to establish a deferral account in connection with certain changes to its liability for nuclear used fuel management and its liability for nuclear decommissioning and low and intermediate level waste management. The deferral account requires OPG to record a regulatory asset or liability representing the revenue requirement impact associated with the changes in these nuclear liabilities arising from an Approved Reference Plan, approved after April 1, 2005, in accordance with the terms of the ONFA. On December 31, 2006, OPG recorded an increase of $1,386 million in these nuclear liabilities arising from the 2006 Approved Reference Plan.

Commencing in the first quarter of 2007 and up to the effective date of the OEB's first order establishing regulated prices, which is expected to be after March 31, 2008, OPG will record a regulatory asset associated with the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan. The OEB is directed by the regulation to ensure that OPG recovers the balance recorded in the deferral account on a straight line basis over a period not to exceed three years, to the extent that the OEB is satisfied that the revenue requirement impacts are accurately recorded.

Income Taxes

OPG is exempt from tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by regulations made under the *Electricity Act, 1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act, 1998* and tax related regulations are relatively new and it has therefore been necessary for OPG, since its inception, to take certain filing positions in calculating the amount of its income tax provision. Certain filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment.

OPG uses the liability method of accounting for income taxes for the unregulated segment of the business and provides future income taxes for income tax temporary differences. The process involves an estimate of OPG's actual current tax liability and an assessment of the Company's future income taxes as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value on the consolidated balance sheet. In addition, OPG has to assess whether the future tax assets can be realized and to the extent that recovery is not considered likely, a valuation allowance must be established. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business in accordance with paragraphs 102 to 104 inclusive of the CICA handbook, Section 3465 – Income Taxes. Accordingly, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that these income taxes are expected to be recovered in future regulated prices charged to customers.

Future tax assets of $228 million (2005 – $269 million) have been recorded on the consolidated balance sheet at December 31, 2006. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards. Because of the adoption of rate regulated accounting, OPG did not record future tax assets of $3,514 million (2005 – $3,297 million), which it would have recorded under the liability method, resulting primarily from temporary differences related to the nuclear fixed asset removal and nuclear waste management provisions.

Future tax liabilities of $477 million (2005 – $492 million) have been recorded on the consolidated balance sheet at December 31, 2006. Because of the adoption of rate regulated accounting, OPG did not record future tax liabilities of $3,686 million (December 31, 2005 – $3,380 million), which it would have recorded under the liability method, resulting primarily from temporary differences related to the nuclear fixed asset removal and nuclear waste management fund.

Fixed Assets

OPG's business is capital intensive and requires significant investment in property, plant and equipment, and at December 31, 2006, the net book value of OPG's fixed assets was $12,761 million.

Property, plant and equipment are tested for recoverability whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Recoverability of property, plant and equipment is determined by comparing the carrying amount of an asset to the undiscounted future net cash flows expected to be generated from the asset over its estimated useful life. In cases where the undiscounted expected future cash flows are less than the carrying amounts, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value, or discounted cash flows.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new and laid-up generating stations, inflation, fuel prices, capital expenditures and station lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors. The Province has accepted the advice of the IESO in their June 2006 report that indicates a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays will be necessary in the plan to replace coal-fired generation by 2009. As a result of these delays, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension will reduce depreciation expense by $126 million in 2007 and $46 million in 2008. From 2009 to 2012, the depreciation expense will increase by $59 million in each year. OPG will reassess the service life of the coal-fired stations upon submission of the IPSP, and as subsequently approved by the OEB. Any change to the estimated service life of the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

During 2006, OPG extended the remaining service life of the Pickering B nuclear generating station to 2014 for depreciation purposes after a review of the life limiting components, taking into account recent station capacity factors. The extension reduced depreciation expense by $36 million in 2006. OPG will continue to review the estimated useful lives of its generating stations, including the Darlington and Bruce nuclear generating units. Any changes resulting from the review will be reflected in 2007.

Pension and Other Post Employment Benefits

OPG's accounting for pension and other post employment benefits are dependent on management's accounting policies and assumptions used in calculating such amounts.

Accounting Policy

In accordance with Canadian generally accepted accounting principles, actual results that differ from the assumptions used, as well as adjustments resulting from changes in assumptions, are accumulated and amortized over future periods and therefore generally affect recognized expense and the recorded obligation in future periods.

Under OPG's policy on accounting for pension and OPEB, certain actuarial gains and losses have not been charged to expense and are therefore not reflected in OPG's pension and OPEB obligations as a result of the following:

- Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.
- For pension and OPEB, the excess of the net cumulative unamortized gain or loss, over 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life.

In addition, past service costs arising from pension and OPEB plan amendments are amortized over future periods and therefore affect recognized expense and the recorded obligation in future periods.

At December 31, 2006, the unamortized net actuarial loss and unamortized past service costs for the pension plan and other post employment benefits amounted to $1,937 million (2005 – $2,760 million). Details of the unamortized net actuarial loss and total unamortized past service costs at December 31, 2006 and 2005 are as follows:

	Registered Pension Plan		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2006**	2005	**2006**	2005	**2006**	2005
Net actuarial (gain) not yet subject to amortization due to use of market-related values	**(677)**	(48)	**–**	–	**–**	–
Net actuarial loss not subject to amortization due to use of corridor	**931**	910	**15**	14	**207**	207
Net actuarial loss subject to amortization	**854**	875	**5**	4	**492**	678
Unamortized net actuarial loss	**1,108**	1,737	**20**	18	**699**	885
Unamortized past service costs	**82**	100	**3**	4	**25**	16

Accounting Assumptions

Assumptions used in determining projected benefit obligations and the costs for the Company's employee benefit plans are evaluated periodically by management in consultation with an independent actuary. Critical assumptions, such as the discount rate used to measure the Company's benefit obligations, the expected long-term rate of return on plan assets and health care cost projections, are evaluated and updated annually. The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields.

A change in these assumptions, holding all other assumptions constant, would increase (decrease) 2006 costs, excluding amortization components, as follows:

(millions of dollars)	Registered Pension Plan	Supplementary Pension Plans	Other Post Employment Benefits
Expected long-term rate of return			
0.25% increase	(20)	na	na
0.25% decrease	20	na	na
Discount rate			
0.25% increase	(11)	–	(3)
0.25% decrease	12	–	3
Inflation			
0.25% increase	36	1	–
0.25% decrease	(34)	(1)	–
Salary increases			
0.25% increase	10	1	–
0.25% decrease	(10)	(1)	–
Health care cost trend rate			
1% increase	na	na	34
1% decrease	na	na	(26)

na – change in assumption not applicable.

Asset Retirement Obligations

OPG's asset retirement obligations are comprised of liabilities for nuclear fixed asset removal and nuclear waste management costs and non-nuclear fixed asset removal costs related to the decommissioning of fossil-fuelled generating stations. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. The estimates of the nuclear liabilities are reviewed on an annual basis as part of the ongoing, overall nuclear waste management program. Changes in the nuclear liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with a corresponding change in the related asset retirement cost capitalized as part of the carrying amount of fixed assets.

The estimates of nuclear fixed asset removal and nuclear waste management costs require significant assumptions in the calculations since the programs run for many years. Significant assumptions underlying operational and technical factors are used in the calculation of the accrued liabilities and are subject to periodic review. Changes to these assumptions, including changes in the timing of programs, technology employed, inflation rate, and discount rate, could result in significant changes in the value of the accrued liabilities.

During the fourth quarter of 2006, OPG reviewed and updated the cost estimates under the ONFA Reference Plan. The Approved Reference Plan (the 2006 Reference Plan) under the ONFA resulted in a $1,386 million increase in OPG's liability for nuclear waste management and decommissioning, and a corresponding increase in the carrying value of the nuclear generating stations to which this liability relates. Changes to the reference plan and cost estimates are mainly due to a change in economic indices, recent industry experience in decommissioning reactors, and additional used fuel and waste quantities resulting from service life extensions.

The increment in the amount of the undiscounted estimated cash flows for OPG's liability for nuclear waste management and decommissioning was discounted using the current credit-adjusted risk-free rate of 4.6 per cent. A ten basis points (0.1 per cent) change in this discount rate would impact the carrying value of the asset retirement obligations by approximately $100 million.

Future Changes in Accounting Policies and Estimates

In 2005, the Canadian Institute of Chartered Accountants issued three new accounting standards: Financial Instruments – Recognition and Measurement, Hedges, and Comprehensive Income. These standards provide guidance on the recognition and measurement of financial assets, financial liabilities and non-financial derivatives. They also provide guidance on the classification of financial instruments and hedge accounting.

These standards are effective for OPG beginning in 2007. OPG has completed assessing the impact of these standards on its consolidated financial statements. The impact of implementing these new standards on OPG's consolidated financial statements is summarized below under the heading *Impact of Adoption*. The following provides further information on each of the three new accounting standards as they relate to OPG.

Comprehensive Income

As a result of adopting these standards, a new category, accumulated other comprehensive income, will be added to shareholder's equity on the consolidated balance sheets. Major components for this category will include unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation amounts, net of hedging, and changes in the fair value of the effective portion of cash flow hedging instruments. These amounts will be recorded in the statement of other comprehensive income until the criteria for recognition in the consolidated statement of income are met.

Financial Instruments – Recognition and Measurement

Under the new standard, for accounting purposes, financial assets will be classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities will be classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading will be measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, will be measured at amortized cost. Available-for-sale instruments will be measured at fair value with unrealized gains and losses recognized in other comprehensive income. The standard also permits designation of any financial instrument as held-for-trading upon initial recognition. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets.

Hedges

This new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a fair value hedging relationship, the carrying value of the hedged item is adjusted by gains or losses attributable to the hedged risk and recognized in net income. This change in fair value of the hedged item, to the extent that the hedging relationship is effective, is offset by changes in the fair value of the derivative. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative will be recognized in other comprehensive income. The ineffective portion will be recognized in net income. The amounts recognized in accumulated other comprehensive income will be reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, foreign exchange gains and losses on the hedging instruments will be recognized in other comprehensive income.

Impact of Adoption

Upon adoption of the financial instruments accounting standards, the assets in the Nuclear Funds that have been carried at amortized cost until the end of 2006, will be classified as held-for-trading in 2007 and reported at fair value. Prior to January 1, 2007, OPG valued securities in the Nuclear Funds based on the closing price of the securities. Starting January 1, 2007, OPG will apply bid pricing, however, the change in the pricing methodology is not expected to have a significant impact to the Nuclear Funds balance on the consolidated balance sheets.

The transition adjustment related to the change in accounting for the funds will be recognized in the opening balance of retained earnings as at January 1, 2007. The transition adjustment for embedded derivatives within long-term contracts will also be recognized in the opening balance of retained earnings as at January 1, 2007. The fair value of hedging instruments designated as cash flow hedges will be recognized in the opening accumulated other comprehensive income on a net of tax basis. The fair values of these hedges are disclosed in Note 12 to the audited consolidated financial statements.

The transition amounts that will be recorded in the opening retained earnings or in the opening accumulated other comprehensive income balance on January 1, 2007 are as follows:

	At Cost	At Fair Value	Transition Amounts – January 1, 2007	
(millions of dollars)	**December 31, 2006**	January 1, 2007	Opening Retained Earnings	Opening Accumulated Other Comprehensive Income
Nuclear funds balance[1]	**7,694**	9,041	1,347	–
Due to Province	**(100)**	(928)	(828)	–
	7,594	8,113	519	–
Accounts receivable and other assets	**325**	372	–	47
Accounts payable and accrued charges	**(989)**	(1,005)	(6)	(10)
Net future income tax liability	**(249)**	(265)	–	(16)
Transition Adjustments			513	21

1 OPG applied bid pricing for securities in the Nuclear Funds. As a result, the fair value of the Nuclear Funds above is lower than that reported under Note 9 of the financial statements. The change in pricing methodology does not have any impact to the overall balance on the consolidated balance sheets because the reduction in fair value is offset by the corresponding change in the due to Province balance.

Balance Sheet Highlights

The following section provides highlights of OPG's audited consolidated financial position using selected balance sheet data:

Selected Balance Sheet Data

As at December 31 (millions of dollars)	2006	2005
Assets		
Accounts receivable	**256**	538
Property, plant and equipment – net	**12,761**	11,412
Nuclear fixed asset removal and nuclear waste management funds	**7,594**	6,788
Regulatory assets	**251**	266
Liabilities		
Accounts payable and accrued charges	**989**	958
Revenue limit rebate payable	**40**	739
Fixed asset removal and nuclear waste management	**10,520**	8,759
Other post employment benefits and supplementary pension plans (long-term portion)	**1,396**	1,212

Accounts Receivable

As at December 31, 2006, accounts receivable were $256 million compared to $538 million as at December 31, 2005. The decrease of $282 million was primarily due to lower electricity generation volume as a result of unseasonably warm weather in December 2006 compared to December 2005.

Property, Plant and Equipment – Net

Net property, plant and equipment as at December 31, 2006 was $12,761 million compared to $11,412 million as at December 31, 2005, an increase of $1,349 million. The increase was primarily due to the change in the estimate for the liability for nuclear fixed asset removal and nuclear waste management of $1,386 million and the corresponding required adjustment to fixed assets. These changes are depreciated over the remaining useful life of the related fixed assets.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG is responsible for the ongoing long-term management and disposal of radioactive waste materials and used fuel resulting from operations and future decommissioning of its nuclear generating stations. OPG's obligations relate to the Pickering and Darlington nuclear generating stations that are operated by OPG, as well as the Bruce A and B nuclear generating stations that are leased by OPG to Bruce Power.

In order to fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund, which are funded by OPG in accordance with the ONFA. The Used Fuel Fund is primarily intended to fund future expenditures associated with the disposal of highly radioactive used nuclear fuel bundles. The Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities, which OPG has been recording as long-term investments at their amortized cost. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements. The Nuclear Funds are referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements. As at December 31, 2006, the value of the Nuclear Funds on an amortized cost basis were $7,594 million compared to $6,788 million as at December 31, 2005.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") for funding related to the first 2.23 million used fuel bundles. OPG recognizes the committed return on the Used Fuel Fund and includes it in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the assets, which includes realized and unrealized returns, is due to or from the Province. Since OPG accounts for the investments in the Nuclear Funds on an amortized cost basis at December 31, 2006, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At December 31, 2006, the Used Fuel Fund included an amount due to the Province of $100 million (December 31, 2005 – $4 million). The Used Fuel Fund asset value, after taking into account the committed return and the related amount due to the Province, was $3,238 million at December 31, 2006 (December 31, 2005 – $2,689 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the audited consolidated financial statements at December 31, 2006, there would be an amount due to the Province of $641 million (December 31, 2005 – $306 million). In addition, under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Under the ONFA, the Decommissioning Fund initially had a long-term target rate of return of 5.75 per cent per annum. Under the 2006 Approved Reference Plan, this rate was revised to 5.15 per cent. OPG bears the risk and liability for cost estimate increases and fund earnings associated with the Decommissioning Fund. According to the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs, approved under the ONFA Reference Plan. At December 31, 2006, based on the estimate of costs to complete under the 2006 Reference Plan, the Decommissioning Fund was fully funded on a market value basis, and underfunded on an amortized cost basis. When the Decommissioning Fund is overfunded on an amortized cost basis, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the amortized cost balance of the Decommissioning Fund would equal the cost estimate of the liability based on the 2006 Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new reference plan is approved with a higher estimated decommissioning liability.

At December 31, 2006, the Decommissioning Fund asset value on an amortized cost basis was $4,356 million compared to a market value of $5,169 million, the difference representing net unrealized gains of $813 million. Under the ONFA, if there is a surplus in the Decommissioning Fund, such that the liabilities, as defined by the 1999 and 2006 ONFA Reference Plans, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to a distribution of an equal amount.

Effective January 1, 2007, OPG adopted the CICA Handbook section 3855, Financial Instruments – Recognition and Measurement. As a result of the adoption, the investments in the Nuclear Funds and the corresponding payables to the Province will be classified as held-for-trading and will be measured at fair value with gains and losses recognized in OPG's consolidated financial statements. As a result of the initial adoption of the standard on January 1, 2007, OPG recorded a transition adjustment of $519 million to opening retained earnings, to adjust the investments in the Nuclear Funds, and the related payables to fair value.

The Province guarantees OPG's annual return in the Used Fuel Fund related to the initial 2.23 million used fuel bundles at the committed return, such that any difference between the committed return and the actual return based on fair value would be offset by the change in the related payable or receivable to the Province in the Used Fuel Fund. Therefore, the new accounting standard does not impact the earnings from the Used Fuel Fund in 2007.

On January 1, 2007, the fair value of the investments in the Decommissioning Fund exceeded the estimated completion costs under the 2006 Approved ONFA Reference Plan.

Accordingly, the Decommissioning Fund balance was reduced by a payable to the Province, as the Decommissioning Fund balance is capped at the estimated completion costs under the 2006 Approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, the earnings from the Decommissioning Fund would be equal to the long-term target rate of return, which is currently 5.15 per cent. If the Decommissioning Fund were underfunded, the earnings for the Decommissioning Fund would reflect actual fund returns at market value.

Regulatory Assets

As at December 31, 2006, regulatory assets were $251 million compared to $266 million as at December 31, 2005. The change in regulatory assets during 2006 was mainly due to the amortization of $25 million of the deferred Pickering A return to service costs, partially offset by $13 million of additional costs that were deferred.

As a result of the change in the Approved Reference Plan, commencing in 2007, OPG will recognize additional expenses including accretion on the fixed asset removal and nuclear waste management liabilities and depreciation of the carrying value of the related fixed assets. The impact of these additional expenses will be reduced by the recognition of a regulatory asset to be recovered through future prices charged to customers, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

Accounts Payable and Accrued Charges

Accounts payable and accrued charges as at December 31, 2006 were $989 million compared to $958 million as at December 31, 2005. The increase of $31 million was partly due to the timing of nuclear fuel purchases and payroll expenditures at year end. The increase was partially offset by a decrease in payables due to the timing of coal purchases and a reduced property tax payable balance.

Revenue Limit Rebate Payable

The revenue limit rebate payable as at December 31, 2006 was $40 million compared to $739 million as at December 31, 2005. During 2006, payments of $860 million were made. The balance of $40 million as at December 31, 2006 represents the revenue limit rebate payable for the period of August 1, 2006 to December 31, 2006. The decrease in the revenue limit rebate payable was partly due to timing, since the $40 million payable at December 31, 2006 represented a period of five months compared to the period of eight months as at December 31, 2005. Furthermore, the revenue limit rebate payable at December 31, 2006 reflected lower electricity prices and generation volume from OPG's unregulated businesses.

Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal (for nuclear and fossil-fuelled generating stations) and nuclear waste management as at December 31, 2006 was $10,520 million compared to $8,759 million as at December 31, 2005. The increase was primarily due to the change in the estimate for the liability for nuclear fixed asset removal and nuclear waste management of $1,386 million resulting from the Approved Reference Plan in accordance with the terms of the ONFA.

OPEB and Supplementary Pension Plans

The long-term portion of the liability for OPEB and supplementary pension plans was $1,396 million as at December 31, 2006 compared to $1,212 million as at December 31, 2005. The increase of $184 million was mainly due to costs recognized in 2006, net of benefit payments.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded on the Company's consolidated financial statements in amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and certain derivative instruments and long-term fixed price contracts.

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. As such, the results of the trust are not consolidated. The securitization provides OPG with an opportunity to obtain an alternative source of cost effective funding. For the year ended December 31, 2006, the average all-in cost of funds was 4.4 per cent and the pre-tax charges on sales to the trust were $13 million. The current securitization agreement extends to August 2009. Refer to Notes 3 and 4 of OPG's 2006 annual audited consolidated financial statements for additional information.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries and joint ventures. Such agreements include guarantees, stand-by Letters of Credit and surety bonds.

Derivative Instruments

The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity. Foreign exchange derivative instruments are used to hedge the exposure to anticipated USD denominated purchases. When such a derivative instrument ceases to exist or when designation of a hedging relationship is terminated, any associated deferred gains or losses are carried forward to be recognized in income in the same period as the corresponding gains or losses associated with the hedged item. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income. The deferred gain on electricity derivative instruments and interest rate hedges was $41 million as at December 31, 2006, compared to a deferred loss of $130 million as at December 31, 2005. For additional information, refer to Note 12 of OPG's audited consolidated financial statements as at and for the year ended December 31, 2006.

All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in Other revenue.

Effective January 1, 2007, OPG adopted the CICA Handbook section 3865 – Hedges. Hedging instruments designated as cash flow hedges will be recognized in opening accumulated other comprehensive income. Adjustments arising due to hedging instruments designated as cash flow hedges will be recognized in the opening balance of accumulated other comprehensive income on a net of tax basis.

Risk Management

OPG's portfolio of generation assets and its electricity trading and marketing operations are subject to inherent risks, including financial, operational, and strategic risks. To manage these risks, OPG's Board of Directors and management have implemented a risk management framework for the governance, identification, measurement, monitoring and reporting of risk across all of OPG and its business operations. Implementation and coordination of risk management activities are undertaken through a centralized risk management group, separate and independent from operational management. Risk information from the business units is independently assessed and aggregated by the Risk Services Group, and is reported by the Chief Risk Officer to the Audit/Risk Committee of the Board of Directors. Risk factors are incorporated into business planning to support the Company's sustainability and achievement of its stated objectives.

While OPG believes it is pursuing appropriate risk management strategies, there can be no assurance that one or more of the risks outlined or other risk factors will not have a material adverse impact on OPG. In particular, the *Electricity Restructuring Act, 2004* (Ontario) and related regulations, the imposition of a revenue limit on the non-regulated assets, and changes in the future mandate of the Company in the Ontario electricity marketplace could have a material impact on OPG.

Risk Classification

OPG's operations face numerous complex risks. For purposes of this discussion, these risks have been grouped together into the following three categories:

- Operational Risk: The risk of loss resulting from external events or inadequate internal processes, equipment and systems. Operational risk can also arise from unexpected or poor human performance involving any key process or function.
- Financial Risk: The risk of financial loss caused by external market factors resulting in unexpected movements in credit, foreign exchange, interest rate, and commodity markets.
- Strategic Risk: The risk that adverse events or conditions in OPG's regulatory, economic, political and social environment will prevent OPG from achieving its objectives. These include risks from adverse regulatory changes or onerous existing regulations; risks from unexpected economic conditions; the risk of financial loss or damaged reputation resulting from unexpected political actions; and the risk inherent in succession planning.

Operational Risks

OPG is exposed to the financial impacts of uncertain output from its generating units. The amount of electricity generated by OPG is affected by fuel supply, equipment malfunction, maintenance requirements, and regulatory and environmental constraints. There is also a risk that an unexpected deterioration of equipment could result in extensive repairs and additional remedial measures. The primary impacts of this risk are increased cost of operations, and the potential derating of a generating unit below its normal level of output.

Nuclear Segment Generation Risks

The uncertainty around the electricity generated by OPG's nuclear generating plants arises from various degradation or aging processes affecting three key types of components: steam generators, fuel channels, and feeders. Generation risks also arise from other structures, components or systems in the nuclear generating stations such as cooling water systems, turbines and reactor structures and components. While OPG has extensive life cycle plans to govern maintenance of the most critical plant life limiting equipment, the depth of coverage does not extend to many other parts of the plant.

OPG maintains a program of preemptive maintenance, which involves inspection and testing to monitor and continue safe operations. When an exposure is suspected or indicated, a specific monitoring program is established. If an exposure is materialized, a resolution program is initiated. Both types of programs usually result in increased operating costs and normally maintain or restore generating capability. One such resolution program currently used is the replacement of piping components, known as feeders.

Feeders are part of the system that transports heat from the reactors to the steam generators that feed the turbines producing electricity. Certain feeders have shown degradation beyond expectations, and will be replaced under the current feeder replacement program. Based on the program's success, the program will be extended if necessary.

OPG's management programs with respect to technology risk and plant conditions impacting operations and safety, involve sharing of operating experience and information with other nuclear operators, and participating in industry-wide or shared research programs as well as the development of investigation methods and remediation tools or methods.

Regulatory Uncertainty
An additional element of technology risks is their impact on nuclear regulation and the changes they bring to technical codes. Operating experience around the world also contributes new knowledge and understanding of both nuclear operations and safety issues, resulting in continually evolving regulatory rules and refining of safety measurements and assessments. Keeping up with these changes adds to cost of operations and in some instances, it may result in a reduction in the productive capacity of a plant, or the premature replacement of a plant component. The divergence of views as to the suitability or depth of safety assessments could result in the imposition of costly remediation measures or curtailment of production.

OPG manages regulatory uncertainty risk by maintaining close contacts with the regulator and issuers of standards/codes. Together with other industry members, OPG is promoting a risk-based mode of regulation.

Hydroelectric Segment Generation Risks
OPG's hydroelectric generating performance is partially dependent on the availability of water, which can vary from year to year due in large part to the weather. The inherent uncertainty in forecasting water levels introduces a significant degree of uncertainty in the capability of hydroelectric generation. OPG manages the risk with production forecasting models, which consider unit efficiency characteristics, water flow conditions and outage plans. Water flows and outage conditions are assessed and monitored on an ongoing basis.

The hydroelectric generating stations vary in age from 14 to 108 years, with an average age of over 71 years. Over 75 per cent of the hydroelectric generating capacity is over 50 years old. Due to the variability and age of the equipment and civil components, there is a risk that some facilities will require significant work and funding to sustain their reliability. OPG manages the reliability risks by conducting ongoing maintenance of critical components, engineering reviews, plant condition assessments, and inspections to identify future work necessary to sustain and, if necessary, upgrade the plant and its equipment. The success of the program is monitored through the measurement of risk reduction and reliability improvements.

The hydroelectric business segment operates 232 dams across the province. To mitigate and manage the risks associated with the operation of these dams, OPG has a dam safety program that performs ongoing maintenance, upgrades and rehabilitation work. OPG also undertakes ongoing dam safety reviews and monitoring, and ad hoc peer reviews. Emergency preparedness and response plans have been established for all facilities to mitigate losses in the event of a dam failure or uncontrolled release of water.

Unregulated – Fossil-Fuelled Segment Risks
The fossil-fuelled generation units can be interrupted by plant and equipment failures. OPG manages and mitigates the risks associated with its fossil-fuelled stations by performing ongoing maintenance and undertaking engineering reviews, condition assessments and critical reviews of maintenance processes. OPG uses the results of these reviews and assessments to make changes to inspection, maintenance, and capital project programs. The risks associated with plant and equipment failures and outages at OPG's fossil generating stations are measured by their availability to produce electricity when called upon.

Major Project Risk
OPG is involved with several major development projects, including: the Niagara Tunnel, Lac Seul, Portlands Energy Centre, other projects supporting operating units, hydroelectric development projects, and the potential refurbishment of existing nuclear generation, and the consideration of new nuclear units at OPG's Darlington nuclear generation site. There is a risk that OPG will have insufficient resources and ability to implement several large projects concurrently. This risk is especially critical given the complexity, long project timelines, and inherent risks related to these projects.

OPG has taken many steps that address the unique challenges relating to the various development projects. OPG utilizes Owner's Representative services to acquire the necessary technical expertise to monitor and control projects. Also, major projects have been contracted on a "design and build" basis, which provides OPG with greater certainty over costs.

For nuclear related projects, OPG has established a new division that has a specific mandate to evaluate the viability of refurbishment of existing nuclear facilities in order to extend their life. The activities of this division include completing plant condition and environmental assessments, developing appropriate project infrastructures and confirming various industry regulatory requirements.

Human Resources Risk
The availability of qualified human resources needed to support existing facilities and complete all the major development projects once they have commenced operations presents a significant risk to OPG. This risk is exacerbated by the increasing number of existing staff

who are approaching early retirement dates. While in the past, the planned shutdown of the coal-fired generating stations alleviated some of these needs, the recent delay in the Province's coal replacement program has increased the quantum of this risk.

The business units have processes to monitor and track demographics and identify potential workforce gaps in critical functions, which support their recruitment activities. Other mitigation measures include enhancements to staff development, succession planning, and training and development programs. OPG also has implemented mentoring programs, and has formed partnerships with various labour groups to market the electricity sector.

Environmental Risk

OPG's Environmental Policy commits OPG to meet all legal requirements and voluntary environmental commitments, integrate environmental factors into business planning and decision-making, and contribute to environmental protection, pollution prevention and energy and resource use efficiency. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") at its generating facilities consistent with the ISO 14001 standard.

OPG monitors emissions into the air and water and regularly reports the results to various regulators, including the Ministry of the Environment, Environment Canada and the Canadian Nuclear Safety Commission. The public also receives ongoing communications regarding OPG's environmental performance through community-based advisory groups, annual environmental reports, community newsletters, open houses and OPG's Web site. OPG has developed and implemented internal monitoring, assessment and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, the treatment of radioactive emissions and radioactive wastes. OPG also continues to address historical land contamination through its voluntary land assessment and remediation program.

OPG's emissions of SO_2 and NO_X are managed through the installation of specialized equipment such as scrubbers, low NO_X burners, and selective catalytic reduction equipment. OPG also purchases low sulphur fuel and utilizes a regulatory approved emissions trading program to manage emission levels within regulatory limits. The Province has directed the OPA to develop a plan to phase out coal-fired generation in the earliest possible timeframe with the assurance that there is an adequate supply of electricity during the phase-out period. Consideration is also being given to emission control technology improvements to mitigate the environmental impacts of generation from coal while these facilities continue to operate. In the interim, OPG will operate its coal-fired facilities in accordance with all regulatory requirements and will implement continuous improvement measures that are consistent with the remaining in-service requirements for these facilities.

OPG's emissions of greenhouse gases ("GHG") have been managed on a voluntary basis, primarily through improvements in energy efficiency and the purchase of GHG emission reduction credits. In October 2006, the Federal Government introduced the *Clean Air Act* as well as the Notice of Intent to Develop and Implement Regulations and Other Measures to Reduce Air Emissions. The Government proposes to regulate CO_2 emissions from certain large emitters and is currently consulting with stakeholders, including OPG. The Government intends to release its proposed regulatory framework in the spring of 2007 and more detailed sector-specific regulations in the spring of 2008. It is possible that OPG could be required to reduce the CO_2 intensity of its fossil stations in the period of 2010 to 2015, most likely through the purchase of CO_2 offsets.

Changes to environmental laws or delays in implementing the current timetable of the Province's coal replacement policy could create compliance risks that may be addressed by the installation of additional equipment or control technologies, the purchase of additional emission reduction credits, or by constraining production from the fossil-fuelled fleet. In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges. Further, some of OPG's activities have the potential to cause contamination to land or water that may require remediation. The potential liability associated with any of these events could have a material adverse effect on the business.

Financial Risk

Commodity Price Risk

Commodity price risk (the risk of changes in the market price of electricity or of the fuels used to produce electricity) will adversely impact OPG's earnings and cash flow from operations. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios to the extent that trading liquidity in the relevant commodities markets provides the economic opportunity to do so. To manage the input risk, OPG has a fuel hedging program, which includes fixed price and indexed contracts for fossil and nuclear fuels, as well as commodity derivatives.

Through a regulation passed pursuant to the *Electricity Restructuring Act, 2004* (Ontario) OPG receives regulated prices for most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates (approximately 60 per cent of OPG generation) from April 1, 2005. These prices are expected to remain in effect until the later of March 31, 2008 and such time that new regulated prices established by the OEB will come into effect. Eighty-five per cent of the remaining unregulated OPG electricity generation, excluding generation from the Lennox generating station and volumes relating to existing contracts, is subject to a revenue limit. To the extent that Ontario spot electricity market prices are below this limit, OPG will assess the recoverability of rebates against future payment amounts.

While a significant portion of OPG's revenue is either fixed or subject to the revenue limit, OPG's revenue is affected by changes in the price of electricity. A $1/MWh increase in the spot price of electricity above the revenue limit rebate threshold would increase OPG's gross margin by approximately $16 million while a $1/MWh decrease below the revenue limit rebate threshold would decrease gross margin by approximately $25 million.

Increases and decreases in the price of electricity result from changes in other factors such as increases and decreases in the supply and demand for electricity. Therefore, the impact of these other factors together with the impact of the revenue limit rebate mechanism results in an asymmetrical impact on gross margin when the price of electricity increases and decreases.

The percentages of OPG's expected generation, emission requirements and fuel requirements hedged are shown below:

	2007	2008	2009
Estimated generation output hedged[1]	93%	91%	70%
Estimated fuel requirements hedged[2]	99%	96%	92%
Estimated nitric oxide (NO) emission requirement hedged[3]	100%	100%	100%
Estimated sulphur dioxide (SO_2) emission requirement hedged[3]	100%	100%	100%

1 Represents the portion of megawatt hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under regulated pricing commitments, agreements with the IESO, OPA auction sales and the revenue limit on OPG's non-prescribed assets.

2 Represents the approximate portion of megawatt hours of expected generation production (and fossil year-end inventory target) from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangements or obligations in order to secure either the expected availability and/or price of fuel and/or fuel related services. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios. Since production from hydroelectric facilities is primarily influenced by expected weather and weather patterns, fuel hedge ratios for hydroelectric facilities are assumed to be 100 per cent.

3 Represents the approximate portion of megawatt hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.

Trading Risk

Open trading positions are subject to measurement against Value at Risk ("VaR") limits. For a given portfolio, VaR measures the possible future loss (in terms of market value) which, under normal market conditions, will not be exceeded within a defined probability and time period. VaR utilization ranged between $1.2 million and $3.4 million during the year ended December 31, 2006, compared to $0.7 million and $3.0 million during the year ended December 31, 2005. VaR utilization is closely monitored in order to ensure compliance with approved limits.

Trading liquidity continues to be constrained in Ontario and interconnected markets due to broader energy market fundamentals. In addition, the revenue limit reduces customer exposure to electricity spot market prices and further limits trading activity.

Liquidity Risk

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects and related maintenance programs at generating stations. In addition, the Company has other significant disbursement requirements including investment in new generating capacity, rebate payments associated with the revenue limit, annual funding obligations under the ONFA, pension funding and continuing debt maturities with the OEFC. A discussion of corporate liquidity is included in the *Liquidity and Capital Resources* section.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange exposure is attributable to two primary factors: USD denominated transactions such as the purchase of fossil fuels; and the influence of USD denominated commodity prices on Ontario electricity spot market prices. The magnitude and direction of the exposure to the USD is affected by generation reliability and the price volatility of USD denominated commodities. OPG currently manages its exposure using forwards and various derivative products to periodically hedge its anticipated USD exposures according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by hedging the exposure in accordance with corporate risk management policies.

Credit Risk

For OPG, credit risk exposure is comprised of two major components: the first is derived from its sales of electricity and the second is derived from its purchases of services and products. As the majority of OPG's sales are derived through the IESO administered spot market, OPG management accepts this credit risk due to the IESO's primary role in the Ontario electricity market. This confidence is based on the IESO's own credit risk management policies and practices, which require all spot market participants to meet specific standards for creditworthiness. Additionally, in the event of a participant default, the loss is shared on a pro-rata basis among all participants thus reducing the specific exposure to OPG.

The following table provides information on credit risk from energy sales and trading activities as at December 31, 2006:

			Potential Exposure for Largest Counterparties	
Credit Rating[1]	Number of Counterparties[2]	Potential Exposure[3]	Number of Counterparties	Counterparty Exposure
		(millions of dollars)		(millions of dollars)
Investment grade	173	139	8	112
Below investment grade	57	20	2	12
IESO[4]	1	385	1	385
Total	231	544	11	509

1 Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.

2 OPG Counterparties are defined by each Master Agreement.

3 Potential exposure is OPG's assessment of maximum exposure over the life of each transaction at 95 per cent confidence.

4 Credit exposure to the IESO peaked at $1,029 million during the year ended December 31, 2006 and at $1,146 million during the year ended December 31, 2005.

OPG's second element of credit risk relates to the exposures created by companies ("counterparties") who are contracted to provide services or products. OPG manages this risk using a comprehensive credit risk management function that independently evaluates all major counterparties and provides continuous input to business units who acquire these services.

Strategic Risks

Regulatory Risk

Effective April 1, 2005, resulting from a regulation passed pursuant to the *Electricity Restructuring Act, 2004* (Ontario) OPG receives regulated prices for most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. These prices are expected to remain in effect until at least March 31, 2008. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend them.

Effective some time after March 31, 2008, the OEB is expected to establish new regulated prices. The process of setting new regulated prices is inherently uncertain. The new prices established by the OEB may not provide for recovery of all of OPG's costs, including an appropriate rate of return. Despite the fact that some costs may not be included within the new prices, these expenditures may still be necessary to maintain the reliability and safety of OPG's regulated generating assets.

The regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) also directed OPG to establish variance accounts for capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 that are associated with certain unforeseen circumstances. In addition, the regulation directed OPG to establish a deferral account for non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A nuclear generating station, and to establish a deferral account related to certain changes in its liability for nuclear used fuel management and its liability for nuclear decommissioning and low and intermediate level waste management. The accuracy and prudence of any variance account balances that OPG seeks to recover must be demonstrated to the OEB as part of the process to establish new regulated prices expected to be effective after March 31, 2008. The accuracy of recording any deferral account balance related to the changes in the nuclear liabilities that OPG seeks to recover must also be demonstrated to the OEB. In the event that some of the amounts recorded in the variance or deferral accounts are disallowed by the OEB at a future date, the amounts disallowed would be reflected in results of operations in the period that the OEB decision occurs.

Following a consultation process throughout 2006, the OEB has concluded that a limited cost of service form of regulation for OPG is appropriate for establishing prices to be effective on or after April 1, 2008. Under cost of service regulation, a rate application process leads to the implementation of new prices based on the total revenue requirement and forecast production.

The OEB has concluded that the first proceeding to establish new prices should focus on a limited set of issues, specifically the appropriate level of OM&A costs for the regulated facilities, the appropriate rate of return on equity, the recovery of balances in the deferral and variance accounts established under the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), the potential to establish a mechanism to maximize the efficient use of the regulated nuclear facilities operated by OPG, and the impact of the capital expenditures for the Niagara Tunnel project. The OEB has also concluded that while a portion of OPG's production from the regulated hydroelectric facilities will continue to receive the Ontario electricity spot market price as an incentive to encourage the efficient use of these assets, it will review the current threshold of 1,900 MWh in any hour above which spot market prices are received by OPG.

The OEB has stated that its first order for prices is expected to be in effect until December 31, 2009, assuming that the OEB's review of OPG's financial and cost data will accommodate this timeframe. OPG expects to file an application for new prices during 2007. The prices established by the OEB can have significant implications on OPG's future financial performance and operating plans.

The exact timing for establishing new prices to be effective after March 31, 2008 remains uncertain at this time. A delay in the effective date of new prices beyond April 1, 2008 would result in a continuation of current prices. The current prices were established by the Province prior to April 1, 2005, based on financial information available at that time. To the extent that these prices do not reflect current costs and operating plans, this could result in deteriorating financial performance.

Risk to Reputation
Loss of a company's reputation is a significant risk, and any of the circumstances outlined could affect OPG's reputation. To mitigate this risk, the Company builds goodwill, uses best practices, is committed to sustainability, ensures transparency, practices leading edge corporate governance and communicates continually with stakeholders. OPG strives to have "no surprises" for stakeholders in order to support its reputation, which is key to achieving the company's strategies and objectives.

Other
OPG's operations are subject to government regulation and direction that may change. Matters that are subject to regulation include: structure of the electricity market, nuclear operations including regulation pursuant to the *Nuclear Safety and Control Act* (Canada), the *Nuclear Liability Act* (Canada) and the *Emergency Plans Act* (Ontario), nuclear waste management and decommissioning, water rentals, environmental matters including air emissions, and proxy tax payments. Because legal requirements can change and are subject to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations.

Related Party Transactions

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

(millions of dollars)	**Revenues 2006**	**Expenses 2006**	Revenues 2005	Expenses 2005
Hydro One				
Electricity sales	**34**	**–**	40	–
Services	**–**	**13**	–	12
Settlement Transactions	**–**	**–**	–	27
Province of Ontario				
GRC water rentals and land tax	**–**	**132**	–	132
Guarantee fee	**–**	**8**	–	8
Used Fuel Fund rate of return guarantee	**–**	**96**	–	–
Decommissioning Fund excess funding	**–**	**(7)**	–	7
OEFC				
GRC and proxy property tax	**–**	**205**	–	207
Interest income on receivable	**–**	**(29)**	–	(75)
Interest expense on long-term notes	**–**	**203**	–	211
Capital tax	**–**	**51**	–	51
Income taxes	**–**	**86**	–	192
Indemnity fees	**–**	**2**	–	5
IESO				
Electricity sales	**5,029**	**146**	6,517	329
Market Power Mitigation Agreement rebate	**–**	**–**	(412)	–
Revenue limit rebate	**(161)**	**–**	(739)	–
Ancillary services	**132**	**–**	68	–
Other	**1**	**1**	–	–
	5,035	**907**	5,474	1,106

At December 31, 2006, accounts receivable included $8 million (2005 – $14 million) due from Hydro One and $71 million (2005 – $324 million) due from the IESO. Accounts payable and accrued charges at December 31, 2006 included $2 million (2005 – $2 million) due to Hydro One.

Corporate Governance

National Instrument 58-101 – Disclosure of Corporate Governance Practices has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices.

Board of Directors and Directorships

OPG's Board of Directors is made up of individuals with substantial expertise in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board exercises its independent supervision over management as follows: the majority of members of the Board are independent of the Company; meetings of the Board are held at least six times a year; a formal Charter for the Board and for each Board Committee has been adopted; each Board Committee is chaired by an independent director; and a portion of each Board and Committee meeting is reserved for directors to meet without management present.

The following are the directors of OPG as at December 31, 2006.

Jake Epp
Calgary, Alberta, Canada

Jake Epp was appointed as Chairman of Ontario Power Generation Inc. in April 2004. He held the position of interim Chairman from December 2003 until his current appointment. Jake Epp was a member of the provincial government's review committee that was created in December 2003 and headed by John Manley to look at OPG's future role in the province's electricity market; examine its corporate and management structure; and decide whether OPG should go ahead with refurbishing three more nuclear reactors at the Pickering A nuclear power plant. The committee's report was presented to the government in March 2004. In May 2003, he was appointed by the Ontario government to lead a panel to review the delays and cost overruns at the Pickering A nuclear generating station. The findings of the report were released in December 2003. He is also certified by the Institute of Corporate Directors.

Mr. Epp's principal occupation is the Chairman of the Board of Directors of Ontario Power Generation Inc., and he serves as a director of QHR Technologies Inc., which is a reporting issuer.

James F. Hankinson
Toronto, Ontario, Canada

James Hankinson was appointed as President and Chief Executive Officer of Ontario Power Generation in May 2005. He has broad management experience in energy, transportation, resource and manufacturing-based businesses. He served as President and Chief Executive Officer of New Brunswick Power Corporation from 1996 to 2002, and during that time had a significant impact on improving the operational and financial position of the company. In 1973, he joined Canadian Pacific Limited, and served as Chief Operating Officer from 1990 to 1995. A chartered accountant, Mr. Hankinson has a Master of Business Administration from McMaster University, and an Honourary Doctor of Laws degree from Mount Allison University. He also sits on the boards of CAE Inc. and Maple Leaf Foods Inc.

Mr. Hankinson's principal occupation is President and Chief Executive Officer, Ontario Power Generation Inc., and he serves as a director for the two reporting issuers CAE Inc. and Maple Leaf Foods Inc.

Donald Hintz
Punta Gorda, Florida, U.S.A.

Donald Hintz is the retired President of Entergy Corporation, where he was responsible for Entergy's 30,000 megawatts of generating assets, including 10 nuclear plants. Prior to his appointment as President he spent seven years as President and CEO of Entergy Operations Inc. where he oversaw the improvement of Entergy's nuclear operations to top quartile performance. Mr. Hintz currently serves on the Board of Entergy Corp. He has a Bachelor of Science in Chemical Engineering from the University of Wisconsin, and has completed the Utility Executive Program and the Advanced Management Program at the University of Michigan and the Harvard Business School, respectively.

Mr. Hintz's principal occupation is retired President of Entergy Corporation and he serves as a director of Entergy Corporation, which is a reporting issuer.

Gary Kugler
Burlington, Ontario, Canada

Dr. Gary Kugler is the retired Senior Vice President, Nuclear Products and Services of Atomic Energy of Canada, Limited (AECL), where he was responsible for all of AECL's commercial operations, including nuclear power plant sales and services worldwide. During his 34 years with AECL, he also held various technical, project management, and business development positions. Prior to joining AECL, he served as a pilot in the Canadian Air Force. Dr. Kugler currently serves as Chairman of the Nuclear Waste Management Organization's Board of Directors. He holds a Bachelor of Science degree in honours physics and a Ph.D. in nuclear physics from McMaster University.

Dr. Kugler's principal occupation is Chairman, Nuclear Waste Management Organization.

M. George Lewis
Toronto, Ontario, Canada

George Lewis is Chairman and Chief Executive Officer of RBC Asset Management Inc. Mr. Lewis is also Executive Vice President, Wealth Management for the Personal and Business Canada division of RBC FG, Canada's largest bank. Formerly he was Managing Director, Head of Institutional Equity Sales, Trading and Research with RBC Capital Markets and was Canada's top-rated analyst for three consecutive years. He has extensive experience in the investment industry and has a Master of Business Administration degree with distinction from Harvard University, a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto and is a chartered financial analyst and chartered accountant. He has also been certified by the Institute of Corporate Directors.

Mr. Lewis' principal occupation is Chairman and Chief Executive Officer of RBC Asset Management Inc.

David J. MacMillan
Barnes, London, United Kingdom

David MacMillan is Non-Executive Director of Intergen N.V., and has extensive international experience in power projects and financing. He is also a former Director of Killingholme Power Limited. Mr. MacMillan holds a Bachelor of Arts and a Master of Arts in Economics from McGill University.

Mr. MacMillan's principal occupation is Financial Advisor.

Corbin A. McNeill Jr.
Jackson, Wyoming, U.S.A.

Corbin McNeill is the retired Chairman and Co-Chief Executive Officer of Exelon Corporation, which was formed by the merger of PECO Energy and Unicom Corp. He joined PECO in 1988 as Executive Vice President, Nuclear and went on to become Chairman, President and CEO. Prior to PECO, he oversaw nuclear operations at the Public Service Electric and Gas Company and the New York Power Authority. Mr. McNeill currently serves as a Director of Owens-Illinois, Inc. and Portland General Electric. He has a Bachelor of Science degree from the U.S. Naval Academy and has completed the Executive Management Program at Stanford University.

Mr. McNeill's principal occupation is retired Chairman and Co-Chief Executive Officer of Exelon Corporation, and he serves as a director for the two reporting issuers Owens-Illinois, Inc. and Portland General Electric Company.

Peggy Mulligan
Mississauga, Ontario, Canada

Peggy Mulligan is Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to her current appointment, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. Mrs. Mulligan holds a Bachelor of Mathematics (Honours) from the University of Waterloo. She was named an FCA by the Institute of Chartered Accountants of Ontario in 2003.

Mrs. Mulligan's principal occupation is Chief Financial Officer, Linamar Corporation, and she serves as a director of Resolve Business Outsourcing Income Fund, which is a reporting issuer.

C. Ian Ross
Collingwood, Ontario, Canada

Ian Ross served at the Richard Ivey School of Business at the University of Western Ontario from 1997 to September 2003. Most recently he held the position of Senior Director, Administration in the Dean's Office, and was also Executive in Residence for the School's Institute for Entrepreneurship, Innovation and Growth. He has served as Governor and President and CEO of Ortech Corporation; Chairman, President and CEO of Provincial Papers Inc.; and President and CEO of Paperbound Industries Corp. Mr. Ross currently serves as a Director for a number of corporations including World Heart Corporation, GrowthWorks Canadian Fund Ltd., PetValu Canada Inc., Comcare Health Services and eJust Systems (formerly Praeda Managements Systems). He is also a member of the Law Society of Upper Canada.

Mr. Ross's principal occupation is Chairman of GrowthWorks Canadian Fund Ltd. and he serves as a director for the following reporting issuers: GrowthWorks Canadian Fund Ltd., PetValu Canada Inc., and World Heart Corporation.

Marie C. Rounding
Toronto, Ontario, Canada

Marie Rounding is a lawyer with Gowling Lafleur Henderson LLP. She is the former President and Chief Executive Officer of the Canadian Gas Association (CGA) and served as Chair of the Ontario Energy Board (OEB) from 1992 to 1998. She has extensive background in regulatory and administrative law, and as a leading regulator she was involved in the deregulation of the natural gas markets and the early restructuring of the electricity sector in Ontario. Ms. Rounding is a graduate of the University of Western Ontario and Osgoode Hall Law School.

Ms. Rounding's principal occupation is Counsel of Gowling Lafleur Henderson LLP.

William Sheffield
Toronto, Ontario, Canada

William Sheffield is the former Chief Executive Officer of Sappi Fine Paper plc., and a former Executive Vice President of International Operations and Corporate Development at Abitibi Consolidated. He has experience in operating large international industries. Mr.Sheffield also spent 17 years with Stelco. He currently serves on the Boards of Velan Inc., Canada Post, Houston Wire & Cable Company and Corby Distilleries. Mr. Sheffield has a Bachelor of Science in

Chemistry from Carleton University, a Master of Business Administration from McMaster University, completed the Advanced Management Program at INSEAD School of Business, France and is certified by the Institute of Corporate Directors.

Mr. Sheffield's principal occupation is Corporate Director, and he serves as a director for the following reporting issuers: Corby Distilleries Ltd., Houston Wire & Cable Company and Velan Inc.

David G. Unruh
Vancouver, British Columbia, Canada

David Unruh is a retired lawyer and energy business executive, currently serving as a director of Westcoast Energy Inc. and Union Gas Limited, both Duke Energy companies. Mr. Unruh is also a director of Catalyst Paper Corporation, Pacific Northern Gas Inc., Corriente Resources Inc., The Wawanesa Mutual Insurance Company, and Canada Line Rapid Transit Inc. Prior to this, Mr. Unruh served as Vice Chairman of Westcoast Energy Inc. and Union Gas Limited, before that as Senior Vice President and General Counsel for Houston-based Duke Energy Gas Transmission and before that as Senior Vice President, Law and Corporate Secretary of Westcoast Energy Inc. Mr. Unruh practiced corporate and commercial law in Winnipeg, Manitoba before joining Westcoast Energy Inc. in Vancouver, British Columbia in 1993.

Mr. Unruh's principal occupation is Corporate Director, and he serves as a director for the following reporting issuers: Catalyst Paper Corporation, Union Gas Limited, Corriente Resources Inc., Westcoast Energy Inc., and Pacific Northern Gas Ltd.

The following lists the membership duration on the Board and Board Committees for each director of OPG. Each director's corresponding attendance at Board and Board Committee meetings for 2006 is disclosed:

Director	Board and Board Committees Membership	2006	Attendance
Jake Epp	Board (since December 2003)	10/10	100%
	Compensation and Human Resources Committee (since November 2004)	6/6	100%
	Governance and Nominating Committee (since August 2005)	6/6	100%
	Nuclear Generation Projects Committee (since November 2006)	1/1	100%
	The Board Chair is invited to attend all other committee meetings	22/22	100%
James F. Hankinson	Board (since December 2003)	9/10	90%
	The President and CEO is invited to attend all committee meetings with the exception of select Compensation and Human Resources Committee meetings	31/34	91%
Donald Hintz	Board (since October 2004)	8/10	80%
	Compensation and Human Resources Committee (since November 2004)	5/6	83%
	Nuclear Operations Committee* (since November 2004)	6/6	100%
	Nuclear Generation Projects Committee (since November 2006)	1/1	100%
Gary Kugler	Board (since September 2004)	10/10	100%
	Audit/Risk Committee (since November 2004)	6/6	100%
	Governance and Nominating Committee (since August 2005)	6/6	100%
	Nuclear Operations Committee (since November 2004)	6/6	100%
	Nuclear Generation Projects Committee (since November 2006)	1/1	100%

Director	Board and Board Committees Membership	2006	Attendance
M. George Lewis	Board (since February 2005)	9/10	90%
	Audit/Risk Committee* (since February 2005)	6/6	100%
	Investment Funds Oversight Committee* (since March 2005)	2/2	100%
David J. MacMillan	Board (since September 2004)	10/10	100%
	Nuclear Operations Committee (since November 2004)	6/6	100%
	Major Projects Committee* (since November 2004)	8/8	100%
Corbin A. McNeill Jr.	Board (since October 2004)	10/10	100%
	Governance and Nominating Committee* (since August 2005)	5/6	83%
	Investment Funds Oversight Committee (since May 2005)	2/2	100%
	Nuclear Operations Committee (since November 2004)	6/6	100%
	Nuclear Generation Projects Committee* (since November 2006)	1/1	100%
Peggy Mulligan	Board (since December 2005)	8/10	80%
	Audit/Risk Committee (since February 2006	5/6	83%
C. Ian Ross	Board (since December 2003)	10/10	100%
	Audit/Risk Committee (since November 2004)	6/6	100%
	Governance and Nominating Committee (since August 2005)	6/6	100%
	Major Projects Committee (since November 2004)	8/8	100%
	Nuclear Generation Projects Committee (since November 2006)	1/1	100%
Marie C. Rounding	Board (since September 2004)	10/10	100%
	Compensation and Human Resources Committee (since November 2004)	6/6	100%
	Investment Funds Committee (since May 2005)	2/2	100%
	Major Projects Committee (since November 2004)	8/8	100%
William Sheffield	Board (since September 2004)	10/10	100%
	Compensation and Human Resources Committee* (since November 2004)	6/6	100%
	Investment Funds Oversight Committee (since February 2005)	2/2	100%
	Major Projects Committee (since November 2004)	8/8	100%

Director	Board and Board Committees Membership	2006	Attendance
David G. Unruh	Board (since September 2004)	10/10	100%
	Compensation and Human Resources Committee (since November 2004)	6/6	100%
	Audit/Risk Committee (since November 2004)	6/6	100%
	Major Projects Committee (since December 2004)	8/8	100%

* Chair of Committee

All directors listed are independent within the meaning of section 1.4 of Multilateral Instrument 52-110 ("MI 52-110") except for James F. Hankinson who is the President and Chief Executive Officer ("CEO") of OPG and Gary Kugler who is the Chairman of the Nuclear Waste Management Organization.

Orientation and Continuing Education

Directors participate in a range of orientation initiatives when they join the OPG Board:

- Directors receive an overview of relevant documentation arising from a new director's election to the Board;
- Directors are provided a Director's Handbook, which provides an overview of the Board's constitution and governance practices, including Shareholder Agreements, Board and Committee Charters, Director roles and responsibilities, Board and Committee chair position descriptions, Board approved corporate policies and Code of Conduct, Director and Officer indemnities and insurance, Board and Committee evaluations, and recent Board activity;
- Directors attend a comprehensive introductory briefing session on OPG's operations and business; and
- Plant tours are provided of OPG generating facilities.

The Board supports the continuing education of directors, in both the business of OPG and their duties as directors, in a number of ways:

- Special presentations are made to the Board or a Committee on specific or unique aspects of OPG's operations, for example, OPG hedging activities and controls, and nuclear waste management;
- Approximately every other Board meeting is preceded by a Board education session. Suggestions for director education sessions are submitted to the Chair of the Governance and Nominating Committee;
- Plant tours to major facilities are arranged in conjunction with director orientation sessions as well as the holding of Board meetings at OPG facilities;
- OPG sponsors director attendance at the Institute of Corporate Directors/Rotman Business School Director College, or equivalent; and
- OPG also provides support to directors for attendance at conferences related to OPG's business or continuing education sessions related to their responsibilities as directors.

Ethical Business Conduct

OPG has a policy for ethical business behaviour and a Code of Business Conduct, which is approved by the Board. The Audit/Risk Committee Charter expressly includes regular reporting by Management on the Code of Business Conduct, including reports on substantiated cases of fraud and the disposition of such cases including disciplinary action. The Audit/Risk Committee also receives an annual report on the Code of Business Conduct in order to satisfy itself that appropriate codes of conduct and compliance programs are in place and are being enforced and remedial action is being taken. A copy of OPG's Code of Business Conduct has been filed on SEDAR (www.sedar.com). The Audit/Risk Committee has also established procedures for the receipt, retention and treatment of complaints received pertaining to internal accounting controls or auditing; matters and the confidential anonymous submission by employees concerning such matters.

The Board has adopted an annual process of written disclosure by directors of information in order to: (i) identify potential conflicts of interest for the purposes of complying with the Ontario Business Corporations Act; (ii) validate their independence and financial literacy for the purposes of complying with securities regulations related to Boards and Audit Committees; and (iii) satisfy other disclosures and filings.

Nomination of Directors

The Governance and Nominating Committee's responsibilities are to: (i) develop and maintain a list of optimum skills which the Board should collectively possess; (ii) recommend a process to identify director candidates; (iii) recommend selection criteria; (iv) identify director candidates to the Board; and (v) recommend to the Board the candidates to stand for election. The Board submits recommended candidates to the Shareholder. Nominations of directors by the Shareholder are also reviewed by the Governance and Nominating Committee.

The Board consists of 12 directors.

Compensation

Director Compensation

In the spring of 2005, the Compensation and Human Resources Committee of the Board retained an independent advisor to benchmark OPG director compensation against companies of similar size, business complexity and risk profile. The Compensation and Human Resources Committee submitted its recommendations for director compensation to the Board for approval. The Board Chair subsequently informed the Shareholder. For 2006, the Governance and Nominating Committee assumed responsibility for annually monitoring and reviewing the level and nature of compensation of directors. Based on the extensive review in 2005 and updated benchmarking, the Governance and Nominating Committee recommended that no change be made to the compensation of directors, with the exception of an increase in the annual retainer for the Audit/Risk Committee chair to ensure that it is both appropriate to the responsibilities and risks assumed, and competitive with other comparable organizations.

Each director who is not an employee of OPG receives an annual retainer of $25,000. Directors also receive a $3,000 annual retainer to chair committees and for each committee that they are a member of. In recognition of the increased duties and responsibilities placed upon the chair of the Audit/Risk Committee as a result of recent regulatory initiatives in North America, the annual retainer for the Audit/Risk Committee chair is $8,000.

Directors are compensated for each meeting that they attend and receive a fee of $1,500 or $750, as determined by the board or committee chair.

In order to retain national and international expertise, non-resident directors are compensated in USDs exchanged at par and directors who travel long distances receive a travel fee to cover travel time related to board and committee meetings they attend.

Directors are also reimbursed for travel and other expenses they incur to attend meetings or to perform other duties in their role as a director.

The chair of the board in his role as non-executive chair receives an all-inclusive annual fee of $150,000 and is reimbursed for out of pocket expenses including travel and other expenses.

CEO Compensation

The Compensation and Human Resources Committee of the Board oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of the CEO's performance, and makes recommendations to the Board with respect to the CEO's compensation. The Compensation and Human Resources Committee seeks input from an independent advisor with regard to monitoring and benchmarking compensation developments.

During 2006, the Compensation and Human Resources Committee of the Board retained an independent advisor from Mercer Human Resource Consulting, to benchmark the compensation package for the President and CEO and to confirm that the compensation package is appropriate given the nature, complexity and risk profile of OPG's business. The Compensation and Human Resources Committee submitted its recommendation to the Board for approval. The Board Chair subsequently informed the Shareholder.

OPG is subject to the *Public Sector Salary Disclosure Act* and is obligated to report salaries over $100,000. For purposes of applying the Act, salaries include bonuses and taxable benefits actually received during that year as reported for personal income tax purposes. Consistent with this reporting requirement, the President and Chief Executive Officer received compensation of $1,488,123, including taxable income and taxable benefits during 2006.

Board Committees

The Board has established seven committees to focus on areas critical to the Company:

Audit/Risk Committee

The Committee is responsible for reviewing the Company's regulatory filings including financial statements, MD&A, and press releases prior to their disclosures to the public. The Committee is also responsible for overseeing the internal audit function, the work of external auditors including their nomination and compensation, that the Company has adequate controls in the financial reporting process and the risk management process, and is in compliance with regulatory and internal policies. The Committee is also responsible for overseeing OPG's policy on ethical behaviour and the Code of Business Conduct, including reports on compliance programs, substantiated cases of fraud and the disposition of such cases including disciplinary action.

Compensation and Human Resources Committee

This Committee focuses on human resources related areas including compensation practices, CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review including succession planning, human resources policies related to employee complaints, diversity and pay equity, organizational design, labour relations, pension plans and policies, and Board compensation, education and evaluation programs.

Governance and Nominating Committee

The Committee develops governance principles for OPG that are consistent with high standards of corporate governance and reviewing and assessing on an ongoing basis OPG's system of corporate governance with a view to maintaining these high standards. The Committee identifies and recommends candidates for election or appointment to the Board to be put before the Shareholder in the event of a vacancy on the Board. Finally, the Committee reviews and recommends OPG's processes for director orientation, assessment, and compensation.

Investment Funds Oversight Committee
This Committee assists the Board in fulfilling its responsibilities for the OPG Pension Fund and the Used Fuel Fund and Decommissioning Fund. The Committee provides oversight of the investment of assets, investment-related liabilities and the management of any surplus (deficit) of the funds. Specifically the Committee: reviews the investment policies, risks and the asset mix; approves annual performance objectives for the investment portfolios; and monitors the performance of the funds.

Major Projects Committee
This Committee assists the Board in providing oversight of major non-nuclear electricity supply projects, including project development, contracting, financing, and construction monitoring.

Nuclear Generation Projects Committee
This Committee was formed in 2006 following direction from the Shareholder to: (i) begin feasibility studies on refurbishing its existing nuclear units; and (ii) begin a federal approvals process, including an environmental assessment, for new nuclear units at an existing site. This Committee assists the Board in providing oversight of the new nuclear plant projects and the refurbishment and life extension projects for existing nuclear plants.

Nuclear Operations Committee
This Committee is responsible for oversight of safe and efficient operations of OPG's nuclear business, regulatory compliance of OPG's nuclear facilities, review of reports from independent oversight of OPG's nuclear operations, reviews of OPG's nuclear management and organization matters, security of OPG's nuclear facilities and substances, and oversight of OPG's nuclear waste and decommissioning liabilities and management.

Assessments
The annual Board & Committee Evaluation is based upon the completion of confidential questionnaires regarding assessment of its performance and the compliance with the Board and Committee Charters. In October 2006, the Governance and Nominating Committee began the process for evaluating Board performance, in addition to Committee Evaluations. The annual process is overseen by the Chair of the Governance and Nominating Committee, who reports the results and recommendations for enhancing oversight to the Board. The Board will begin to assess individual directors in the 2007 evaluation process.

Further Information on OPG Governance
OPG provides additional information on OPG's governance on its Web site (www.opg.com) including:

- Memorandum of Understanding
- Shareholder Directives
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Code of Business Conduct Policy
- Disclosure Policy

Audit/Risk Committee Information

MI 52-110 has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective and independent audit committees, which enhance the quality of financial disclosure and ultimately foster increased investor confidence in Canada's capital markets. Information on OPG's Audit/Risk Committee, which includes the text of the Audit/Risk Committee Charter, updated during 2006, is as follows:

Audit/Risk Committee Charter

Purpose
The purpose of the Audit/Risk Committee (the "Committee") is to assist the Board in fulfilling its oversight responsibilities by reviewing, advising and making recommendations to the Board on:

- The integrity, quality and transparency of the Company's financial information;
- The adequacy of the financial reporting process;
- The systems of internal controls and risk management, and the Company's related principles, policies and procedures which Management have established;
- The performance of the Company's internal audit function and the external auditors;
- The external auditors' qualifications and independence;
- The Company's compliance with related legal and regulatory requirements and internal policies; and
- The promotion of a culture of ethical business conduct and compliance with OPG's Code of Business Conduct.

The function of the Audit/Risk Committee is oversight. Management is responsible for the preparation, presentation and integrity of the consolidated financial statements of the Company. Management of the Company is responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations.

Organization

Members

The Audit/Risk Committee shall consist of three or more independent directors appointed by the Board of Directors, none of whom shall be employees of the Company or any of the Company's affiliates. A majority of the members of the Committee, but not less than two, will constitute a quorum. As a venture issuer, OPG is exempt from the statutory requirements of MI 52-110 requiring members of Audit Committees to be independent. However, OPG considers such independence to be "best practice" and, therefore, each of the members of the Audit/Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing the Company.

The Board of Directors shall designate one member of the Audit/Risk Committee as the Committee Chair. Members of the Audit/Risk Committee shall serve at the pleasure of the Board of Directors for such term or terms as the Board of Directors may determine. The Board of Directors shall confirm that each member of the Audit/Risk Committee is financially literate as such qualification is interpreted by the Board of Directors in its business judgment and in compliance with MI 52-110 and its Companion Policy.

Meetings

The Committee will meet at least quarterly or more frequently as circumstances require and at any time at the request of a member. The Committee will meet regularly and at least annually with the external auditors, the internal auditors and Management in separate sessions to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in the Company's financial information or regulatory filings any report from the Audit/Risk Committee required by applicable laws and regulations and stating among other things whether the Audit/Risk Committee has:

- Reviewed and discussed the audited consolidated financial statements with Management;
- Discussed pertinent matters with the internal and external auditors;
- Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence; and
- Recommended to the Board of Directors that the audited consolidated financial statements be included in the Company's Annual Report.

Authority

While the Audit/Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit/Risk Committee to plan or conduct audits or risk assessments, or to determine that the Company's consolidated financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management.

In carrying out its oversight responsibilities, the Audit/Risk Committee and the Board will necessarily rely on the expertise, knowledge and integrity of the Company's Management, and internal and external auditors.

The Audit/Risk Committee shall have the authority to set and pay the compensation for any advisors employed by the Committee.

The Audit/Risk Committee shall have the authority to communicate directly with the internal and external auditors.

Delegation of Authority

The Committee may delegate to any employee of OPG or a sub-committee the authority to: (i) execute or carry out any decision of the Committee; and/or (ii) exercise any right, power or function of the Committee on such terms and conditions and within such limits as the Committee may establish, except that the Committee may not delegate its oversight responsibilities.

Access to Management and Outside Advisors

The Audit/Risk Committee shall have unrestricted access to members of Management and relevant information. The Audit/Risk Committee may retain independent counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

Committee Responsibilities and Duties

The Committee shall:

General

- Conduct or authorize investigations into any matters within the Committee's scope of responsibilities;
- Review and recommend approval to the Board, the appointment or replacement of the CFO and the CRO.

Risk Management and Internal Controls

- Review and evaluate the Company's policies and processes for assessing significant risks or exposures and the steps Management has taken to monitor and control such risks to the Company, including the organizational structure and the adequacy of resources;
- Consider and review with the CRO and Management the critical risks to the Company, the potential impact of such risks, and related mitigation;

- Ascertain whether the Company has an effective process for determining risks and exposure from actual and potential litigation and claims relating to non-compliance with laws and regulations;
- Review with Management, reports demonstrating compliance with risk management policies;
- Review with the Company's General Counsel and others any legal, tax, or regulatory matters that may have a material impact on Company operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty;
- Review with Management, internal audit, and the external auditors, the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls;
- Review disclosures made by the CEO and CFO during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in the Company's internal controls; and
- Review the expenses of the Chairman, Board, President and the President's direct reports on a semi-annual basis, and of any other senior officers and employees the Committee considers appropriate.

Internal Audit

- Evaluate the internal audit process and define expectations in establishing the annual internal audit plan and the focus on risk, including the organizational structure and the adequacy of resources;
- Approve the Charter of the internal audit function annually;
- Evaluate the audit scope and role of internal audit; and
- Consider and review with the CRO and Management:
  - Significant findings and Management's response including the timetable for implementation of Management Actions to correct weaknesses;
  - Any difficulties encountered in the course of their audit (such as restrictions on the scope of their work or access to information);
  - Any changes required in the planned scope of the audit plan; and
  - The internal audit budget.

External Auditor

- Recommend to the Board of Directors the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, and the compensation of the external auditor;
- Oversee the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, including the resolution of disagreements between Management and the external auditor regarding financial reporting;
- Review the independence and qualifications of the external auditor;
- At least annually, obtain and review a report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and the Company;
- Review the scope and approach of the annual audit plan with the external auditors;
- Discuss with the external auditor the quality and acceptability of the Company's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management;
- Assess the external auditor's process for identifying and responding to key audit and internal control risks;
- Ensure the rotation of the lead audit partner every five years and other audit partners every seven years, and consider regular rotation of the audit firm;
- Evaluate the performance of the external auditor annually and present its findings to the Board of Directors;
- Determine which non-audit services the external auditor is prohibited by law or regulation, or as determined by the Audit/Risk Committee, from providing and pre-approve all services provided by the external auditors. The Committee may delegate such pre-approval authority to a member of the Committee. The decision of any Committee member to whom pre-approval authority is delegated must be presented to the full Audit/Risk Committee at its next scheduled meeting;
- Review and approve all related party transactions; and
- Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company.

Financial Reporting

- Review with Management and the external auditors the Company's interim financial information and disclosures under MD&A and earnings press release, prior to filing;
- Satisfy itself that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's consolidated financial statements, other than the public disclosure referred to above, and periodically assess the adequacy of those procedures;
- Review with Management and the external auditors, at the completion of the annual audit:
  - The Company's annual financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by the Company or that the Company otherwise files with the OSC;
  - The external auditors' audit of the consolidated financial statements and their report;
  - Any significant changes required in the external auditors' audit plan;
  - Any difficulties or disputes with Management encountered during the audit;
  - The Company's accounting principles; and
  - Other matters related to conduct, which should be communicated to the Committee under generally accepted auditing standards.
- Review significant accounting and reporting issues and understand their impact on the consolidated financial statements. These include complex or unusual transactions and highly judgmental areas; major issues regarding accounting principles and financial presentations, including significant changes in the Company's selection or application of accounting principles; and the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements, on the consolidated financial statements of the Company;
- Review analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative Generally Accepted Accounting Principles methods; and
- Advise Management, based upon the Audit/Risk Committee's review and discussion, whether anything has come to the Committee's attention that causes it to believe that the consolidated financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

Compliance with Code of Business Conduct

- Review the administration of and compliance with the Company's Code of Business Conduct to ensure that appropriate codes of conduct and compliance programs are in place, are being enforced and remedial action is being taken, as well as the process for communicating the Code of Business Conduct to Company personnel; and
- Monitor through regular updates from Management regarding compliance matters.

Treatment of Complaints

- Establish procedures for the receipt, recording and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and
- Establish procedures for the confidential and anonymous submission by employees of concerns regarding accounting or auditing matters of the Company.

Annual Review and Assessment

The Committee shall conduct an annual review and assessment of its performance, including a review of its compliance with this Charter, in accordance with the evaluation process approved by the Board.

The Committee shall also review and assess the adequacy of this Charter on an annual basis taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship, and if appropriate, shall recommend changes to the Board.

Composition of the Audit/Risk Committee

OPG's Audit/Risk Committee consists of George Lewis, Dr. Gary Kugler, Peggy Mulligan, Ian Ross, and David Unruh. As a venture issuer, OPG is exempt from the provisions of securities regulations, which require that members of an Audit Committee be independent and financially literate. OPG's Board of Directors has, however, decided that, in keeping with best practice, each member of OPG's Audit/Risk Committee should meet the independence and financial literacy requirements in accordance with the requirements of the securities regulations known as MI 52-110. The Board of Directors has concluded that all of the members of OPG's Audit/Risk Committee are financially literate and that four of the five members of the Committee are independent of OPG and its subsidiaries, within the meaning of MI 52-110.

Dr. Kugler does not meet the statutory definition of being independent as a result of being the Chairman of the Nuclear Waste Management Organization (the "NWMO"), a not-for-profit organization of which New Brunswick Power, Hydro-Québec and OPG are members. Dr. Kugler was appointed to the NWMO Board by OPG and was subsequently appointed Chairman by the NWMO Board. The NWMO has been established under the *Nuclear Fuel Waste Act* to investigate approaches for managing Canada's used nuclear fuel and implement the approach that is selected by the government. OPG plays a significant role in the funding and leadership of the NWMO, which results in Dr. Kugler no longer being independent of OPG, according to MI 52-110. The Board of Directors believes that Dr. Kugler's service as NWMO Chairman is in the best interests of OPG, the NWMO, and OPG's stakeholders, in view of his experience and extensive knowledge of the Canadian nuclear industry, and that his involvement with the NWMO does not affect his ability to exercise impartial judgment and fulfill his responsibilities as a member of the OPG Audit/Risk Committee. In view of OPG's nuclear operations and related financial and waste management obligations, Dr. Kugler's experience and knowledge is also considered a key input to the planning and risk management components of the Committee's mandate. As a result, OPG's Board of Directors has determined that it is appropriate for Dr. Kugler to serve as a non-independent member of that Committee, in accordance with section 3.3(2) of MI 52-110.

Relevant Education and Experience

Financially literate means having the ability to read and understand the accounting principles used by OPG to prepare its consolidated financial statements, and the ability to address the breadth and level of complex accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by OPG's consolidated financial statements. Each member had an understanding of internal controls and procedures for financial reporting. The education and experience of each Audit/Risk Committee member that are relevant to his or her performance as an audit committee member may be found in the Corporate Governance section.

Audit/Risk Committee Oversight

There have been no recommendations of OPG's Audit/Risk Committee to nominate or compensate an external auditor which have not been adopted by its Board of Directors.

External Auditor Service Fees

The following fees were billed by Ernst & Young LLP:

(thousands of dollars)	2006	2005
Audit Fees	**1,250**	1,251
Audit-Related Fees	**335**	277
Tax Fees and Other	**300**	320

Audit Fees

These fees included the audit of OPG's consolidated financial statements, quarterly reviews of the financial statements, and the pension fund audits.

Audit-Related Fees

These fees included work with respect to internal controls, accounting assistance, French translation of consolidated financial statements and MD&A, and special audits and reviews. During 2006, OPG has employed the services of other professional advisers, particularly in the areas of internal controls and accounting assistance.

Tax Fees and Other

These fees included tax services related to assistance with matters raised by the Tax Auditors for the 1999 taxation year and a United States state tax review.

Internal Controls over Financial Reporting and Disclosure Controls

Management, including the President and CEO and Chief Financial Officer (CFO), are responsible for maintaining disclosure controls and procedures and internal control over financial reporting. Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with GAAP.

An evaluation of the effectiveness of design and operation of OPG's disclosure controls and procedures was conducted as of December 31, 2006. Management, including the President and the CEO and the CFO, has evaluated the effectiveness of OPG's disclosure controls and procedures (as defined in Multilateral Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*, of the Canadian Securities Administrators) as of December 31, 2006. Management has concluded that, as of December 31, 2006, OPG's disclosure controls and procedures were effective to provide reasonable assurance that material information relating to OPG and its consolidated subsidiaries and interests in jointly controlled entities would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

Management has designed internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and has concluded, as of December 31, 2006, that the design of internal controls over financial reporting was effective.

There were no changes in internal control over financial reporting that have materially affected or are reasonably likely to materially affect OPG's internal control over financial reporting.

Fourth Quarter

Overview of Results

Net loss for the three months ended December 31, 2006 was $19 million compared to net income of $160 million for the same period in 2005. Loss before income taxes for the three months ended December 31, 2006 was $82 million compared to income before income taxes of $192 million for the same period in 2005.

The following is a summary of the factors impacting OPG's results for the three months ended December 31, 2006 compared to results for the same period in 2005, on a before-tax basis:

(millions of dollars – before tax) (unaudited)	
Income before income taxes for the three months ended December 31, 2005	**192**
Changes in gross margin	
Decrease in electricity sales prices after revenue limit rebate	(74)
Change in electricity generation by segment:	
Regulated – Nuclear	(75)
Regulated – Hydroelectric	8
Unregulated – Hydroelectric	6
Unregulated – Fossil-Fuelled	(46)
Other changes in gross margin	8
	(173)
Increase in pension and other post employment benefit costs	(47)
Increase in nuclear maintenance and repairs	(36)
Increase in nuclear outages	(55)
Write-off of excess inventory related to Pickering A Units 2 and 3 in 2005	35
Decrease in depreciation expense primarily due to extension of service lives of the coal-fired generating stations, Pickering B station and Unit 4 of the Pickering A station	27
Other changes	(3)
Decrease in income before income taxes, excluding impairment of long-lived assets	**(252)**
Impairment of long-lived assets	(22)
Loss before income taxes for the three months ended December 31, 2006	**(82)**

Earnings for the three months ended December 31, 2006 were significantly affected by a reduction in gross margin from electricity sales due primarily to lower average sales prices and lower electricity generation compared to the same period in 2005. The decrease in electricity prices was primarily due to lower average Ontario spot market prices applicable to electricity generation from OPG's unregulated business segments. The lower electricity generation in the fourth quarter of 2006 compared to the same period in 2005 was primarily due to extended planned and unplanned outages at OPG's nuclear generating stations and lower Ontario demand which continued to unfavourably impact the fossil-fuelled generating stations.

For the three months ended December 31, 2006, OM&A expenses were $810 million compared to $686 million in the same period in 2005. The increase of $124 million was primarily due to higher pension and OPEB costs mainly due to changes in economic assumptions used to measure the costs and an increase in maintenance and repairs on OPG's nuclear and fossil-fuelled generating stations, which reflected OPG's continued objective of maintaining the reliability of the stations. In addition, an increase in unplanned outages at certain nuclear generating stations unfavourably affected earnings in the fourth quarter of 2006 compared to the same period in 2005. During the three months ended December 31, 2005, OPG wrote off excess inventory of $35 million acquired for the anticipated return to service of Units 2 and 3 at the Pickering A nuclear generating station, which did not reoccur in 2006.

Earnings were favourably affected by a decrease in depreciation expense of $27 million during the three months ended December 31, 2006 compared to the same period in 2005. The decrease was primarily due to the extension of the service lives of all of the coal-fired generating stations, as a result of delays in the plan to replace coal-fired generation.

OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations in the three months ended December 31, 2006 of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result of changes in circumstance, which included a decrease in forecast Ontario spot market prices and the extension of the lives of the coal-fired stations. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives.

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under this method, future income tax assets and liabilities associated with these segments are not recognized where those future income taxes are expected to be recovered in the regulated prices charged to customers in the future. As a result, OPG did not record a future tax expense of $47 million and $46 million for the rate regulated segments during the three months ended December 31, 2006 and 2005, respectively, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method.

Discussion of Operating Results

(millions of dollars) (unaudited)	2006	2005
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**1,276**	1,496
Fuel expense	**267**	314
Gross margin	**1,009**	1,182
Operations, maintenance and administration	**810**	686
Depreciation and amortization	**160**	187
Accretion on fixed asset removal	**124**	118
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(97)**	(102)
Property and capital taxes	**24**	43
Restructuring	**–**	4
(Loss) income before impairment of long-lived assets	**(12)**	246
Impairment of long-lived assets	**22**	–
(Loss) income before interest and income taxes	**(34)**	246

Revenue

(millions of dollars) (unaudited)	2006	2005
Regulated generation sales[1]	**665**	751
Spot market sales, net of hedging instruments	**453**	841
Revenue limit rebate	**(13)**	(262)
Variance accounts	**(4)**	1
Other	**175**	165
Total revenue	**1,276**	1,496

1 Regulated generation sales included revenue of $46 million and $65 million that OPG received at the Ontario spot market price for Regulated – Hydroelectric generation over 1,900 MWh in any hour during the fourth quarter of 2006 and 2005, respectively.

Revenue

Revenue was $1,276 million for the three months ended December 31, 2006 compared to $1,496 million during the same period in 2005. The decrease of $220 million was primarily due to lower average spot electricity prices impacting OPG's unregulated business segments combined with lower nuclear and fossil-fuelled generation of 3.2 TWh compared to the same period in 2005.

Electricity Prices

OPG's average sales price for the three months ended December 31, 2006 was 4.5¢/kWh compared to 5.0¢/kWh for the same period in 2005. The decrease was primarily due to lower average Ontario spot market prices in the fourth quarter of 2006, which significantly affected OPG's unregulated business segments.

Fuel Expense
Fuel expense was $267 million for the three months ended December 31, 2006 compared to $314 million during the same period in 2005. The decrease of $47 million was primarily due to lower generation from the fossil-fuelled stations compared to the same period in 2005.

Operations, Maintenance and Administration
OM&A expenses for the three months ended December 31, 2006 were $810 million compared to $686 million during the same period in 2005. The increase of $124 million in OM&A expenses was primarily due to higher pension and other post employment benefit costs and an increase in repairs and maintenance for the nuclear generating stations.

Property and Capital Taxes
Property and capital taxes for the three months ended December 31, 2006 was $24 million, compared to $43 million during the same period in 2005. The $19 million decrease was primarily due to additional municipal property tax assessments for OPG's fossil-fuelled generating station received in the fourth quarter of 2005, which did not occur in 2006.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable business segment, net of the revenue limit rebate for the three months ended December 31, 2006 and 2005, were as follows:

	Three Months Ended December 31	
(¢/kWh)	**2006**	2005
Weighted average hourly Ontario spot electricity market price	**4.5**	7.5
Regulated – Nuclear	**4.9**	4.9
Regulated – Hydroelectric	**3.5**	3.9
Unregulated – Hydroelectric	**4.5**	5.5
Unregulated – Fossil-Fuelled	**4.6**	5.6
OPG's average sales price	**4.5**	5.0

The continued decrease in Ontario's spot electricity market price significantly contributed to the decline in OPG's average sales price for the three months ended December 31, 2006 compared to the same period in 2005.

Electricity Generation

Total electricity sales volume for the three months ended December 31, 2006 was 24.3 TWh compared to 27.1 TWh during the same period in 2005. The decrease was primarily due to lower nuclear generation due to higher planned and unplanned outage days and a decrease in generation from the fossil-fuelled stations due to lower Ontario demand.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2006 was $91 million compared to $446 million for the three months ended December 31, 2005. The unfavourable change in cash flow was primarily due to lower revenue before rebates as a result of lower Ontario spot market prices and lower volumes. A revenue limit rebate payment of $58 million was made in the three months ended December 31, 2006, which did not occur in the three months ended December 31, 2005.

Investment in fixed assets during the three months ended December 31, 2006 was $215 million compared with $141 million during the same period in 2005. The increase in capital expenditures of $74 million was primarily due to increased investment in the Portlands Energy Centre, the Niagara Tunnel project, and the Lac Seul project.

OPG negotiated agreements with the OEFC to finance the Niagara Tunnel project, the Portlands Energy Centre and the Lac Seul project. Advances under these credit arrangements commenced during the fourth quarter and amounted to $160 million for the Niagara Tunnel, $90 million for the Portlands Energy Centre and $20 million for the Lac Seul project.

Quarterly Financial Highlights

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the twelve most recently completed quarters. This financial information has been prepared in accordance with Canadian GAAP.

	2006 Quarters Ended				
(millions of dollars) (unaudited)	**December 31**	**September 30**	**June 30**	**March 31**	**Total Year**
Revenue after revenue limit rebate	**1,276**	**1,435**	**1,345**	**1,508**	**5,564**
Net (loss) income	**(19)**	**167**	**143**	**199**	**490**
Net (loss) income per share	**$(0.08)**	**$0.65**	**$0.56**	**$0.78**	**$1.91**

	2005 Quarters Ended				
(millions of dollars) (unaudited)	December 31	September 30	June 30	March 31	Total Year
Revenue after revenue limit and Market Power Mitigation Agreement rebates	1,496	1,571	1,373	1,358	5,798
Income (loss) before extraordinary item	160	181	137	(38)	440
Income (loss) before extraordinary item per share	$0.62	$0.71	$0.53	$(0.15)	$1.71
Net income (loss)	160	181	63	(38)	366
Net income (loss) per share	$0.62	$0.71	$0.25	$(0.15)	$1.43

	2004 Quarters Ended				
(millions of dollars) (unaudited)	December 31	September 30	June 30	March 31	Total Year
Revenue after Market Power Mitigation Agreement rebate	1,215	1,212	1,141	1,350	4,918
Net income (loss)	34	(15)	(41)	64	42
Net income (loss) per share	$0.13	$(0.06)	$(0.16)	$0.25	$0.16

Balance Sheet as at December 31 (millions of dollars)	**2006**	2005	2004
Total assets	**22,750**	21,623	19,830
Total long-term liabilities	**15,408**	13,640	13,366
Cash dividend declared per share (dollars)	**$0.50**	–	–
Common shares outstanding (millions)	**256.3**	256.3	256.3

OPG's quarterly results are affected by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. Since April 1, 2005, revenue has increased due to the introduction of regulated prices for most of OPG's baseload hydroelectric and all of the nuclear facilities that it operates and other related regulatory changes. The revenue limit and the Market Power Mitigation Agreement rebates, regulated prices, and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.

Additional items which affected net income in certain quarters above include the following:

- Increase in depreciation expense in 2004 due to the planned early shutdown of coal-fired generating stations and an increase in fixed assets in service;
- Tax benefit of $93 million recorded during the fourth quarter of 2004 related to the elimination of a valuation allowance due to the introduction of rate regulation;
- Lower OM&A expenses due to the deferral of non-capital costs related to the planned return to service of all units at the Pickering A nuclear generating station units return to service project, beginning January 1, 2005, as required by a regulation pursuant to the Electricity Restructuring Act, 2004 (Ontario);
- Impairment loss on the Lennox generating station of $202 million recorded during the first quarter of 2005, reflecting the amount of the carrying value of the station;
- Higher revenues as a result of a reliability must-run contract between OPG and the IESO for the Lennox generating station, for the period October 1, 2005 to September 30, 2006;
- Lower income tax expense due to the use of the taxes payable method for the regulated segments commencing April 1, 2005;
- Impairment loss of $63 million related to Units 2 and 3 of the Pickering A nuclear generating station, recorded in the second quarter of 2005;
- One-time extraordinary loss of $74 million recorded in the second quarter of 2005, resulting from the adoption of rate regulated accounting and the corresponding use of the taxes payable method;
- Write-off of $22 million and $35 million of excess inventory as a result of not returning Pickering A nuclear generating station Units 2 and 3 to service recorded in the third and fourth quarters of 2005 respectively;
- Higher depreciation expense related to the return to service of Unit 1 at the Pickering A generating station in the fourth quarter of 2005;
- Decrease in depreciation expense primarily due to extension of service lives, for accounting purposes, of the Nanticoke station in the third quarter of 2005, and the Pickering B nuclear generating station and Unit 4 of the Pickering A nuclear generating station beginning in the first quarter of 2006;
- Higher pension and OPEB costs from 2004 to 2006 mainly due to changes in economic assumptions used to measure the costs; and
- Decrease in depreciation expense primarily due to extension of the service life, for accounting purposes, of all coal-fired generating stations to December 31, 2012, beginning in the third quarter of 2006.

Supplemental Earnings Measures

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, audited consolidated financial statements as at and for the year ended December 31, 2006 and 2005 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian GAAP and therefore may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements and notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) **Gross margin** is defined as revenue less revenue limit and Market Power Mitigation Agreement rebates and fuel expense.

(2) **Earnings** is defined as net income.

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Statement of Management's Responsibility for Financial Information

Ontario Power Generation Inc.'s ("OPG") management is responsible for presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and the requirements of the Ontario Securities Commission ("OSC"), as applicable. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal control and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and sound and conservative accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of OPG's disclosure controls and procedures (as defined in Multilateral Instrument 52-109 of the Canadian Securities Administrators) as of December 31, 2006. Management concluded that, as of December 31, 2006, OPG's disclosure controls and procedures were effective to provide reasonable assurance that material information relating to OPG and its consolidated subsidiaries and interests in jointly controlled entities would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

Management has designed internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Accordingly, we, as OPG's Chief Executive Officer and Chief Financial Officer, will certify OPG's annual disclosure documents filed with the OSC, which includes attesting to the design and effectiveness of OPG's disclosure controls and procedures and the design of internal control over financial reporting.

The Board of Directors, based on recommendations from its Audit/Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit/Risk Committee, had direct and full access to the Audit/Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jim Hankinson
President and Chief Executive Officer

Donn W. J. Hanbidge
Chief Financial Officer

February 14, 2007

Auditors' Report

To the Shareholder of Ontario Power Generation Inc.

We have audited the consolidated balance sheets of Ontario Power Generation Inc. as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of Ontario Power Generation Inc.'s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Licensed Public Accountants

Toronto, Canada
February 14, 2007

Consolidated Statements of Income

Years Ended December 31 (millions of dollars except where noted)	2006	2005
Revenue (Note 19)		
Revenue before revenue limit and Market Power Mitigation Agreement rebates	**5,725**	6,949
Revenue limit rebate (Note 16)	**(161)**	(739)
Market Power Mitigation Agreement rebate (Note 17)	**–**	(412)
	5,564	5,798
Fuel expense	**1,098**	1,297
Gross margin	**4,466**	4,501
Expenses (Note 19)		
Operations, maintenance and administration	**2,777**	2,516
Depreciation and amortization (Note 5)	**664**	753
Accretion on fixed asset removal and nuclear waste management liabilities (Note 9)	**499**	476
Earnings on nuclear fixed asset removal and nuclear waste management funds (Note 9)	**(371)**	(381)
Property and capital taxes	**106**	107
Restructuring	**–**	10
	3,675	3,481
Income before the following:	**791**	1,020
Impairment of long-lived assets (Note 5)	**22**	265
Income before interest, income taxes and extraordinary item	**769**	755
Net interest expense	**193**	197
Income before income taxes and extraordinary item	**576**	558
Income tax expense (Note 10)		
Current	**60**	80
Future	**26**	38
	86	118
Income before extraordinary item	**490**	440
Extraordinary item (Note 10)	**–**	74
Net income	**490**	366
Basic and diluted income per common share before extraordinary item (dollars)	**1.91**	1.72
Basic and diluted income per common share (dollars)	**1.91**	1.43
Common shares outstanding (millions)	**256.3**	256.3

See accompanying notes to the consolidated financial statements

Consolidated Statements of Retained Earnings

Years Ended December 31 (millions of dollars)	2006	2005
Retained earnings (deficit), beginning of year	**261**	(105)
Net income	**490**	366
Dividend (Note 19)	**(128)**	–
Retained earnings, end of year	**623**	261

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

Years Ended December 31 (millions of dollars)	2006	2005
Operating activities		
Net income	**490**	366
Adjust for non-cash items:		
Depreciation and amortization (Note 5)	**664**	753
Accretion on fixed asset removal and nuclear waste management liabilities (Note 9)	**499**	476
Earnings on nuclear fixed asset removal and nuclear waste management funds (Note 9)	**(371)**	(381)
Pension cost (Note 11)	**218**	115
Other post employment benefits and supplementary pension plans (Note 11)	**255**	181
Future income taxes	**26**	38
Transition rate option contracts (Note 15)	**(12)**	(36)
Provision for restructuring	**–**	10
Mark-to-market adjustment on energy contracts	**(29)**	23
Provision for used nuclear fuel	**33**	28
Impairment of long-lived assets (Note 5)	**22**	265
Excess inventory write-off	**–**	57
Regulatory assets and liabilities (Note 6)	**27**	11
Extraordinary item (Note 10)	**–**	74
Other	**(11)**	18
	1,811	1,998
Contributions to nuclear fixed asset removal and nuclear waste management funds (Note 9)	**(454)**	(454)
Expenditures on fixed asset removal and nuclear waste management (Note 9)	**(164)**	(90)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management (Note 9)	**19**	23
Contributions to pension fund (Note 11)	**(261)**	(254)
Expenditures on other post employment benefits and supplementary pension plans (Note 11)	**(69)**	(65)
Revenue limit rebate (Note 16)	**(860)**	–
Market Power Mitigation Agreement rebate (Note 17)	**–**	(851)
Expenditures on restructuring	**(8)**	(18)
Net changes to other long-term assets and liabilities	**(94)**	(92)
Changes in non-cash working capital balances (Note 23)	**477**	1,004
Cash flow provided by operating activities	**397**	1,201
Investing activities		
Increase in regulatory assets (Note 6)	**(13)**	(265)
Investment in fixed assets (Notes 5 and 18)	**(637)**	(494)
Proceeds on sale of other fixed assets	**–**	3
Net proceeds from purchase of long-term investments	**–**	(4)
Cash flow used in investing activities	**(650)**	(760)
Financing activities		
Issuance of long-term debt (Note 8)	**270**	495
Repayment of long-term debt (Note 8)	**(806)**	(4)
Dividend paid	**(128)**	–
Net increase (decrease) in short-term notes (Note 7)	**15**	(26)
Cash flow (used in) provided by financing activities	**(649)**	465
Net (decrease) increase in cash and cash equivalents	**(902)**	906
Cash and cash equivalents, beginning of year	**908**	2
Cash and cash equivalents, end of year	**6**	908

See accompanying notes to the consolidated financial statements

Consolidated Balance Sheets

As at December 31 (millions of dollars)	**2006**	2005
Assets		
Current assets		
Cash and cash equivalents	**6**	908
Accounts receivable (Notes 4 and 19)	**256**	538
Future income taxes (Note 10)	**–**	18
Fuel inventory (Note 18)	**669**	581
Materials and supplies (Note 18)	**112**	115
	1,043	2,160
Fixed assets (Notes 5 and 18)		
Property, plant and equipment	**17,136**	15,172
Less: accumulated depreciation	**4,375**	3,760
	12,761	11,412
Other long-term assets		
Deferred pension asset (Note 11)	**706**	663
Nuclear fixed asset removal and nuclear waste management funds (Note 9)	**7,594**	6,788
Long-term materials and supplies (Note 18)	**326**	273
Regulatory assets (Note 6)	**251**	266
Long-term accounts receivable and other assets	**69**	61
	8,946	8,051
	22,750	21,623

See accompanying notes to the consolidated financial statements

Consolidated Balance Sheets

As at December 31 (millions of dollars)	2006	2005
Liabilities		
Current liabilities		
Accounts payable and accrued charges (Notes 11, 15, and 19)	**989**	958
Revenue limit rebate payable (Note 16)	**40**	739
Short-term notes payable (Note 7)	**15**	–
Long-term debt due within one year (Note 8)	**406**	806
Future income taxes (Note 10)	**3**	–
Deferred revenue due within one year	**12**	12
Income and capital taxes payable (Note 10)	**128**	81
	1,593	2,596
Long-term debt (Note 8)	**2,953**	3,089
Other long-term liabilities		
Fixed asset removal and nuclear waste management (Note 9)	**10,520**	8,759
Other post employment benefits and supplementary pension plans (Note 11)	**1,396**	1,212
Long-term accounts payable and accrued charges	**150**	183
Deferred revenue	**132**	144
Future income taxes (Note 10)	**246**	241
Regulatory liabilities (Note 6)	**11**	12
	12,455	10,551
Shareholder's equity		
Common shares (Note 13)	**5,126**	5,126
Retained earnings	**623**	261
	5,749	5,387
	22,750	21,623

Commitments and Contingencies (Notes 2, 5, 7, 8, 9, 10, 12, 14 and 18)

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

Honourable Jake Epp
Chairman

M. George Lewis
Director

Notes to the Consolidated Financial Statements for the Years Ended December 31, 2006 and 2005

1 Description of Business

Ontario Power Generation Inc. was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario). As part of the reorganization of Ontario Hydro, under the *Electricity Act, 1998* and the related restructuring of the electricity industry in Ontario, Ontario Power Generation Inc. and its subsidiaries (collectively "OPG" or the "Company") purchased and assumed certain assets, liabilities, employees, rights and obligations of the electricity generation business of Ontario Hydro on April 1, 1999 and commenced operations on that date. Ontario Hydro has continued as Ontario Electricity Financial Corporation ("OEFC"), responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations.

2 Basis of Presentation

These consolidated financial statements were prepared in accordance with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

The consolidated financial statements include the accounts of OPG and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant intercompany transactions have been eliminated on consolidation.

Certain of the 2005 comparative amounts have been reclassified from financial statements previously presented to conform to the 2006 financial statement presentation.

3 Summary of Significant Accounting Policies

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost or market.

Interest earned on cash and cash equivalents and short-term investments of $21 million (2005 – $13 million) at an average effective rate of 4.0 per cent (2005 – 2.8 per cent) is offset against interest expense in the consolidated statements of income.

Sales of Accounts Receivable

Asset securitization involves selling assets such as accounts receivable to independent entities or trusts, which buy the receivables and then issue interests in them to investors. These transactions are accounted for as sales, given that control has been surrendered over these assets in return for net cash consideration. For each transfer, the excess of the carrying value of the receivables transferred over the estimated fair value of the proceeds received is reflected as a loss on the date of the transfer, and is included in net interest expense. The carrying value of the interests transferred is allocated to accounts receivable sold or interests retained according to their relative fair values on the day the transfer is made.

Fair value is determined based on the present value of future cash flows. Cash flows are projected using OPG's best estimates of key assumptions, such as discount rates, weighted average life of accounts receivable and credit loss ratios.

As part of the sales of accounts receivable, certain financial assets are retained and consist of interests in the receivables transferred. Any retained interests held in the receivables are accounted for at cost. The receivables are transferred on a fully serviced basis and do not create a servicing asset or liability.

Inventories

Fuel inventory is valued at weighted average cost.

Materials and supplies are valued at the lower of average cost or net realizable value with the exception of critical replacement parts that are unique to OPG's generating stations. The cost of the critical replacement parts inventory is charged to operations on a straight-line basis over the remaining life of the related facilities and is classified in long-term assets.

Fixed Assets and Depreciation

Property, plant and equipment are recorded at cost. Interest costs incurred during construction are capitalized as part of the cost of the asset based on the interest rate on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are also charged to depreciation expense. Repairs and maintenance are expensed when incurred.

Fixed assets are depreciated on a straight-line basis except for computers, and transport and work equipment, which are depreciated on a declining balance basis as noted below:

Nuclear generating stations and major components	15 to 49 years[1]
Fossil generating stations and major components	25 to 40 years[2]
Hydroelectric generating stations and major components	25 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

1 The end of station life for depreciation purposes for the Darlington, Pickering A, Pickering B, and Bruce B nuclear generating stations ranges between 2012 and 2021. Major components are depreciated over the lesser of the station life and the life of the components. The Bruce A nuclear generating station was fully depreciated in 2003. Bruce Power decided to refurbish the Bruce A generating station contributing to an increase in the asset retirement obligation at December 31, 2006 and an increase in the carrying value of the Bruce A station. The station will now be depreciated over the period to 2030.

2 Commencing July 1, 2006, the end of station life for depreciation purposes for the coal-fired generating stations was changed to 2012, due to the expected shutdown of these stations by the end of 2012. The Lennox generating station is depreciated to 2016.

Impairment of Fixed Assets

OPG evaluates its property, plant and equipment for impairment whenever conditions indicate that estimated undiscounted future net cash flows may be less than the net carrying amount of assets. In cases where the undiscounted expected future cash flows are less than the carrying amount, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available.

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* (Ontario) received royal assent. A regulation made pursuant to that statute provides that OPG receives regulated prices beginning April 1, 2005 for most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. This includes electricity generated by Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and the Pickering A and B, and Darlington nuclear generating stations. The regulation was amended in February 2007. The amendment clarified certain aspects of the regulation and directed OPG to establish a deferral account related to certain changes in its liability for nuclear used fuel management and its liability for nuclear decommissioning and low and intermediate level waste management.

OPG's regulated prices were established by the Province of Ontario (the "Province") based on a forecast of production volumes and total operating costs, and a return on rate base, which assumed an average five per cent return on equity. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets, deferred charges, and an allowance for working capital. The initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that new regulated prices to be established by the Ontario Energy Board ("OEB") will take effect. If there are changes to the fundamental assumptions on which the initial prices were developed, the Province may amend these initial prices.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the consolidated financial statements as regulatory assets and liabilities. When the regulation provides sufficient assurance that incurred costs will be recovered in the future, then OPG may defer those costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, then OPG reports a regulatory liability. Also, if the regulation provides for lesser or greater than planned revenue to be received or returned by OPG through future regulated prices, then OPG recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation. See the Company's revenue recognition policy and Notes 6 and 10 to the consolidated financial statements for additional disclosures required under rate regulated accounting.

Long-Term Portfolio Investments

Long-term portfolio investments, other than investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV"), are stated at amortized cost and include the nuclear fixed asset removal and nuclear waste management funds. Gains and losses on long-term investments are recognized in other income when investments are sold. When a decline in the value of investments occurs, which is considered to be other than temporary, a provision for loss is established.

In accordance with Accounting Guideline 18, Investment Companies ("AcG-18"), investments owned by OPGV are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated based on readily available market information or using estimation techniques based on historical performance.

Fixed Asset Removal and Nuclear Waste Management Liability

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liability is increased by the present value of the variable cost portion of the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Expenses relating to low and intermediate level waste are charged to depreciation and amortization expense. Expenses relating to the disposal or storage of nuclear used fuel are charged to fuel expense. The liability may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liability, a gain or loss would be recorded.

Accretion arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time. The resulting expense is included in operating expenses.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining useful life of the related fixed assets and is included in depreciation expense.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province of Ontario, OPG established a Used Fuel Fund and a Decommissioning Fund (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund expenditures associated with the disposal of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

The Nuclear Funds are invested in fixed income and equity securities, which OPG records as long-term investments and accounts for at their amortized cost value. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements. After applying the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, Financial Instruments – Recognition and Measurement in 2007, the Nuclear Funds will be measured at fair value with gains and losses recognized in net income. More detail on the impact of the new accounting standards is provided in the Future Accounting Changes section.

Revenue Recognition

All of OPG's electricity generation is sold into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO"). Prior to April 1, 2005, revenue was recorded as electricity was generated and metered based on the spot market sales price, net of the Market Power Mitigation Agreement rebate and hedging activities. At each balance sheet date, OPG computed the average spot energy price that prevailed since the beginning of the current settlement period and recognized a Market Power Mitigation Agreement rebate if the average price exceeded 3.8¢/kilowatt hour ("kWh"), based on the amount of energy subject to the rebate.

Effective April 1, 2005, the generation from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates became rate regulated. As a result, energy revenue generated from the nuclear facilities is recognized based on a regulated price of 4.95¢/kWh. The regulated price received by OPG for the first 1,900 megawatt hours (MWh) of production from the regulated hydroelectric facilities in any hour is 3.3¢/kWh. Any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price.

The production from OPG's remaining hydroelectric, fossil-fuelled and wind generating stations remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from these other generating assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets are also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate. This revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning May 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these two revenue limits are returned to the IESO for the benefit of consumers.

OPG also sells into, and purchases from, interconnected markets of other provinces and the U.S. northeast and midwest. All contracts that are not designated as hedges are recorded in the consolidated balance sheets at market value with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $163 million in 2006 and $228 million in 2005 were netted against revenue.

OPG derives non-energy revenue under the terms of a lease arrangement with Bruce Power L.P. ("Bruce Power") related to the Bruce nuclear generating stations. This includes lease revenues, interest income and revenues for engineering analysis and design, technical and ancillary services. OPG also earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, non-energy revenue includes isotope sales to the medical industry and real estate rentals. Revenues from these activities are recognized as services are provided or as products are delivered.

Accounting for Certain Leases

OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. Under the cash basis of accounting, OPG recognizes lease income as stipulated in the lease agreement to the extent that the lease payments are expected to be included in future regulated prices charged to customers.

If OPG did not apply the cash basis of accounting for leases and the taxes payable method for the related income tax accounting in 2006, the revenue and the related future income tax expense would have increased by $21 million (2005 – $15 million) and $6 million (2005 – $5 million) respectively.

As of December 31, 2006, had OPG accounted for the leases related to the regulated business using a straight-line basis and the related income taxes using the liability method, OPG would have reported a deferred lease receivable of $36 million (2005 – $15 million) and a related future income tax liability of $11 million (2005 – $5 million).

Derivatives

OPG is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the wholesale price of electricity, OPG enters into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized in income over the term of the contract when the underlying hedged transactions occur. These gains or losses are included in unregulated revenue and are not recorded on the consolidated balance sheets. All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in other revenue.

OPG also enters into derivative contracts with major financial institutions to manage the Company's exposure to foreign currency movements. Foreign exchange translation gains and losses on these foreign currency denominated derivative contracts are recognized as an adjustment to the purchase price of the commodity or goods received.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded through net income in the period incurred.

OPG utilizes emission reduction credits ("ERCs") and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances are held in inventory and charged to OPG's operations at average cost as part of fuel expense as required. Options to purchase ERCs are accounted for as derivatives and are recorded at estimated market value.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. When such derivative instrument ceases to exist or be effective as a hedge, or when designation of a hedging relationship is terminated, any associated deferred gains or losses are carried forward to be recognized in income in the same period as the corresponding gains or losses associated with the hedged item. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at year-end exchange rates. Any resulting gain or loss is reflected in other revenue.

Research and Development

Research and development costs are charged to operations in the year incurred. Research and development costs incurred to discharge long-term obligations such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Pension and Other Post Employment Benefits

OPG's post employment benefit programs include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, group life insurance, health care and long-term disability benefits. OPG accrues its obligations under pension and other post employment benefit ("OPEB") plans. The obligations for pension and other post retirement benefit costs are determined using the projected benefit method pro-rated on service. The obligation for long-term disability benefits is determined using the projected benefit method on a terminal basis. The obligations are affected by salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions. The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields.

Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPEB plan amendments are amortized on a straight-line basis over the expected average remaining service life of the employees covered by the plan, since OPG will realize the economic benefit over that period. Due to the long-term nature of post-employment liabilities, the excess of the net cumulative unamortized gain or loss, over 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets, is also amortized over the expected average remaining service life.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Taxes

Under the *Electricity Act, 1998*, OPG is responsible for making payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes of its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in future regulated prices charged to customers.

OPG makes payments in lieu of property tax on its nuclear and fossil-fuelled generating assets to the OEFC, and also pays property taxes to municipalities.

OPG pays charges on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense.

Changes in Accounting Policies and Estimates

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Effective January 1, 2006, following the completion of a review of the life limiting components of the Pickering B nuclear generating station, OPG revised and extended, for the purpose of calculating depreciation, the estimated remaining service life of the Pickering B nuclear generating station to 2014 from 2009. The extension reduced depreciation expense by $36 million in 2006.

The Province has accepted the advice of the IESO in their June 2006 report that indicates a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays will be necessary in the Province's plan to replace coal-fired generation by 2009. As a result of these delays, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension reduces depreciation expense by $64 million in 2006, $126 million in 2007, and $46 million in 2008. From 2009 to 2012, the depreciation expense will increase by $59 million in each year. OPG will reassess the service life of the coal-fired stations upon release of the submitted Integrated Power System Plan, and as subsequently approved by the OEB. Any change to the estimated service life of the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

OPG will continue to review the estimated useful lives of its generating stations including the Darlington and Bruce nuclear generating units. Any changes resulting from the review would be reflected in 2007.

Reportable Segments

As noted in Note 18, effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates became rate regulated. OPG continues to receive the spot market price for the output from its other generating stations, subject to a revenue limit on the majority of this output. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Commencing in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified to reflect the revised disclosure.

Future Accounting Changes

In 2005, the CICA issued three new accounting standards: Handbook Section 1530, Comprehensive Income; Handbook Section 3855, Financial Instruments – Recognition and Measurement; and Handbook Section 3865, Hedges. These standards apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006.

These standards are effective for OPG beginning in 2007. OPG has completed assessing the impact of these standards on its consolidated financial statements. The impact of implementing these new standards on OPG's consolidated financial statements is summarized below under the heading Impact of Adoption. The following provides further information on each of the three new accounting standards as they relate to OPG.

Comprehensive Income

As a result of adopting these standards, a new category, accumulated other comprehensive income, will be added to shareholder's equity in the consolidated balance sheets. Major components for this category will include unrealized gains and losses on financial assets classified as available-for-sale, changes in the fair value of the effective portion of cash flow hedging instruments, and unrealized foreign currency translation amounts, net of hedging, arising from self-sustaining foreign operations. These amounts will be recorded in the statement of other comprehensive income until the criteria for recognition in the consolidated statement of income are met.

Financial Instruments – Recognition and Measurement

Under the new standard, for accounting purposes, financial assets will be classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities will be classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading will be measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, will be measured at amortized cost. Available-for-sale instruments will be measured at fair value with unrealized gains and losses recognized in other comprehensive income. The standard also permits designation of any financial instrument as held-for-trading upon initial recognition. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets.

Hedges

This new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a fair value hedging relationship, the carrying value of the hedged item is adjusted by gains or losses attributable to the hedged risk and recognized in net income. This change in fair value of the hedged item, to the extent that the hedging relationship is effective, is offset by changes in the fair value of the derivative. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative will be recognized in other comprehensive income. The ineffective portion will be recognized in net income. The amounts recognized in accumulated other comprehensive income will be reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, foreign exchange gains and losses on the hedging instruments will be recognized in other comprehensive income.

Impact of Adoption

Upon adoption of the financial instruments accounting standards, the assets in the Nuclear Funds that have been carried at amortized cost until the end of 2006, will be classified as held-for-trading in 2007 and reported at fair value. The transition adjustment related to the change in accounting for the funds will be recognized in the opening balance of retained earnings as at January 1, 2007. The transition adjustment for embedded derivatives within long-term contracts will also be recognized in the opening balance of retained earnings as at January 1, 2007. Prior to January 1, 2007, OPG valued securities in the Nuclear Funds based on the closing price of the securities. Starting January 1, 2007, OPG will apply bid pricing, however, the change in the pricing methodology is not expected to have a significant impact to the Nuclear Funds balance on the consolidated balance sheets. The fair value of hedging instruments designated as cash flow hedges will be recognized in the opening accumulated other comprehensive income on a net of tax basis. The fair values of these hedges are disclosed in Note 12 to the audited consolidated financial statements.

The transition amounts that will be recorded in the opening retained earnings or in the opening accumulated other comprehensive income balance on January 1, 2007 are as follows:

		Transition Amounts – January 1, 2007		
(millions of dollars)	**At Cost December 31, 2006**	At Fair Value January 1, 2007	Opening Retained Earnings	Opening Accumulated Other Comprehensive Income
Nuclear funds balance[1]	**7,694**	9,041	1,347	–
Due to Province	**(100)**	(928)	(828)	–
	7,594	8,113	519	–
Accounts receivable and other assets	**325**	372	–	47
Accounts payable and accrued charges	**(989)**	(1,005)	(6)	(10)
Net future income tax liability	**(249)**	(265)	–	(16)
Transition adjustments			513	21

1 OPG applied bid pricing for securities in the Nuclear Funds. As a result, the fair value of the Nuclear Funds above is lower than that reported under Note 9 of the financial statements. The change in pricing methodology does not have any impact to the overall balance on the consolidated balance sheets because the reduction in fair value is offset by the corresponding change in the due to Province balance.

4 Sale of Accounts Receivable

On October 1, 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables. In December 2005, the Company extended this agreement to August 2009.

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust net of the undivided co-ownership interest retained by the Company. For 2006, OPG has recognized pre-tax charges of $13 million (2005 – $9 million) on such sales at an average cost of funds of 4.4 per cent (2005 – 3.1 per cent). As at December 31, 2006, OPG had sold receivables of $300 million from its total portfolio of $392 million.

The accounts receivable reported and securitized by the Company are as follows:

	Principal Amount of Receivables as at December 31		Average Balance of Receivables for Year Ended December 31	
(millions of dollars)	**2006**	2005	**2006**	2005
Total receivables portfolio[1]	**392**	668	**445**	559
Receivables sold	**300**	300	**300**	300
Receivables retained	**92**	368	**145**	259
Average cost of funds			**4.4%**	3.1%

1 Amount represents receivables outstanding, including receivables that have been securitized, which the Company continues to service.

An immediate 10 per cent or 20 per cent adverse change in the discount rate would not have a material effect on the current fair value of the retained interest. There were no credit losses for the year ended December 31, 2006 and 2005.

Details of cash flows from securitizations for the years ended December 31, 2006 and 2005 are as follows:

(millions of dollars)	**2006**	2005
Collections reinvested in revolving sales[1]	**3,600**	3,600
Cash flows from retained interest	**2,020**	2,927

1 Given the revolving nature of the securitization, the cash collections received on the receivables securitized are immediately reinvested in additional receivables resulting in no further cash proceeds to the Company over and above the initial cash amount of $300 million. The amounts reflect the total of 12 monthly amounts.

5 Fixed Assets

Depreciation and amortization expense consists of the following:

(millions of dollars)	**2006**	2005
Depreciation and amortization	**659**	748
Nuclear waste management costs	**5**	5
	664	753

Fixed assets consist of the following:

(millions of dollars)	**2006**	2005
Property, plant and equipment		
Nuclear generating stations	**6,275**	4,754
Regulated Hydroelectric generating stations	**4,384**	4,379
Unregulated Hydroelectric generating stations	**3,481**	3,447
Fossil-Fuelled generating stations	**1,465**	1,411
Other fixed assets	**854**	833
Construction in progress	**677**	348
	17,136	15,172
Less: accumulated depreciation		
Generating stations	**4,066**	3,497
Other fixed assets	**309**	263
	4,375	3,760
	12,761	11,412

Interest capitalized to construction in progress at 6.0 per cent during the years ended December 31, 2006 and 2005 was $21 million and $27 million, respectively.

Impairment of Long-Lived Assets

The accounting estimates related to asset impairment require significant management judgment to identify factors such as short and long-term forecasts for future sales prices, the supply of electricity in Ontario, inflation, fuel prices, and station lives. The amount of the future cash flow that OPG will ultimately realize with respect to these assets could differ materially from the carrying values recorded in the consolidated financial statements.

Pickering A Nuclear Generating Station Units 2 and 3

OPG completed, in the second quarter of 2005, an assessment of the cost, schedule and risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. The assessment considered results from inspection programs with respect to feeder pipe and steam generator degradation mechanisms, and potential degradation of the calandria vault components, all of which could impact the future capability factor, operating costs and the life of the units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, OPG determined that the return to service of these two units was not justified on a commercial basis even though technically feasible. OPG recorded an impairment loss of $63 million in the second quarter of 2005 related to the carrying amount of these two units including construction in progress. In addition to the impairment loss for these two units, OPG recorded OM&A expenses of $57 million related to the write-off of inventory identified as excess or unusable, as a result of not returning Units 2 and 3 to service.

OPG expects to recover the amounts recorded in the deferral account established under a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) relating to non-capital costs incurred on or after January 1, 2005 associated with the return to service of Units 2 and 3. The deferred costs relating to Units 2 and 3 are disclosed in Note 6 to the audited consolidated financial statements.

Lennox Generating Station

As a result of the Government's "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" released in September 2004 and the related contractual arrangements, future wholesale electricity market revenue is expected to be lower than previously anticipated. As a relatively high variable cost generating station, the Lennox generating station will not be able to recover its fixed operating costs and its carrying value from the wholesale electricity market in the future. Given these factors, OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. In March 2005, OPG was advised by the Province that it would continue to support OPG in negotiating an arrangement that would allow for the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result of this change in circumstance, OPG recorded the impairment loss of $202 million in the first quarter of 2005.

In March 2006, the OEB issued a decision approving a reliability must-run ("RMR") contract between OPG and the Independent Electricity System Operator ("IESO") for the Lennox generating station, for the period October 1, 2005 to September 30, 2006. Reliability must-run contracts are designed to ensure that generating stations remain available to maintain the reliability of the electricity system. In its decision, the OEB found it appropriate for OPG to recover the fixed and variable operating costs of the Lennox generating station that are not recovered through market revenues. As a result of the decision, OPG recorded $59 million in revenue in 2006. The RMR contract is a cost-based contract that provides for regular payments, which are subject to adjustments for actual costs. OPG negotiated a similar contract with the IESO for the period October 1, 2006 to September 30, 2007. The contract was approved by the OEB in January 2007.

Thunder Bay and Atikokan Generating Stations

OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations in 2006 of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result of changes in circumstance, which included a decrease in forecast Ontario spot market prices and the extension of the lives of the coal-fired stations. The fair value of the coal-fired generating stations, which was determined using a discounted cash flow method, was compared to the carrying value of the generating assets to determine the impairment loss. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives.

6 Regulatory Assets and Liabilities

The regulatory assets and liabilities as at December 31, 2006 and 2005 are as follows:

(millions of dollars)	**2006**	2005
Regulatory assets		
Pickering A generating station return to service costs	**249**	261
Ancillary service revenue variance	**–**	5
Transmission outages and transmission restrictions variance	**2**	–
Total regulatory assets	**251**	266
Regulatory liabilities		
Hydroelectric production variance	**4**	4
Other	**7**	8
Total regulatory liabilities	**11**	12

The changes in the regulatory assets and liabilities for 2006 and 2005 are as follows:

(millions of dollars)	Pickering A Return to Service Costs	Ancillary Service Revenue Variance	Hydro-electric Production Variance	Transmission Outages and Transmission Restrictions Variance	Other
Regulatory assets (liabilities), January 1, 2005	–	–	–	–	–
Increase (decrease) during the year	265	5	(4)	–	(8)
Amortization during the year	(4)	–	–	–	–
Regulatory assets (liabilities), December 31, 2005	261	5	(4)	–	(8)
Increase (decrease) during the year	13	(5)	–	2	1
Amortization during the year	(25)	–	–	–	–
Regulatory assets (liabilities), December 31, 2006	**249**	**–**	**(4)**	**2**	**(7)**

Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004* (Ontario), OPG was required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A nuclear generating station. As a result, the change in accounting was prospectively adopted on January 1, 2005. As at December 31, 2006, the deferral account was $249 million, consisting of non-capital costs of $232 million relating to Unit 1, $19 million relating to Units 2 and 3, $20 million of general return to service costs, interest of $7 million, and accumulated amortization of $29 million.

As at December 31, 2005, the deferral account was $261 million, consisting of non-capital costs of $228 million relating to Unit 1, $19 million relating to Units 2 and 3, $11 million of general return to service costs, interest of $7 million, and accumulated amortization of $4 million.

Under the regulation, the OEB is directed to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years.

Had OPG not charged costs to the deferral account as required by the regulation, OM&A expenses would have been reduced by $12 million (2005 – would have been increased by $254 million). Further, the net interest expense would have been $7 million higher in 2005.

Variance Accounts and Other Regulatory Balances

Effective April 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004* (Ontario), OPG was directed to establish variance accounts for capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions, unforeseen changes to nuclear regulatory requirements or unforeseen technological changes, changes to revenues for ancillary services from the regulated facilities, acts of God (including severe weather events), and transmission outages and transmission restrictions. OPG recorded a reduction in revenue during 2006 of $5 million, reflecting ancillary services revenue that was favourable compared to the forecast for 2006 provided to the Province for the purposes of establishing regulated prices. OPG recorded revenue during 2006 of $2 million reflecting lower generation sales caused by transmission outages and transmission restrictions in 2006.

OPG recorded revenue during 2005 of $5 million, reflecting ancillary services revenue that was unfavourable compared to that forecasted for 2005. OPG recorded a reduction in revenue during 2005 of $4 million, reflecting water conditions that were favourable compared to those forecasted for 2005.

The OEB is directed by the regulation to ensure recovery of amounts recorded in the variance accounts to the extent that the OEB is satisfied that the revenues recorded in the accounts were earned or foregone, that the costs recorded in the accounts were prudently incurred, and that both revenues and costs are accurately recorded. Any balances approved by the OEB will be amortized over a period not to exceed three years. The amortization will commence when OPG starts to recover the balances through new prices that will be set by the OEB. Any balances in the account disallowed by the OEB will be reflected in results of operations in the period that the OEB decision occurs.

The other regulatory liability includes a portion of non-regulated revenue earned by OPG's regulated assets, which may result in a reduction of future regulated prices to be established by the OEB.

Had OPG not accounted for the variance accounts and other regulatory balances as regulatory assets and liabilities, revenue for 2006 would have been higher by $2 million (2005 – lower by $1 million).

Liability for Nuclear Used Fuel Management and Liability for Nuclear Decommissioning and Low and Intermediate Level Waste Management

In February 2007 the Province amended a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to require OPG to establish a deferral account in connection with certain changes to its liability for nuclear used fuel management and its liability for nuclear decommissioning and low and intermediate level waste management. The deferral account requires OPG to record a regulatory asset or liability representing the revenue requirement impact associated with the changes in these nuclear liabilities arising from an Approved Reference Plan, approved after April 1, 2005, in accordance with the terms of the ONFA. Revenue requirement is a regulatory construct, which represents all costs and a return on rate base at an allowed rate of return that the regulator determines to be appropriate. On December 31, 2006, OPG recorded an increase of $1,386 million in these nuclear liabilities arising from the 2006 Approved Reference Plan.

Commencing on January 1, 2007 and up to the effective date of the OEB's first order establishing regulated prices, which is expected to be after March 31, 2008, OPG will record a regulatory asset associated with the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan. The OEB is directed by the regulation to ensure that OPG recovers the balance recorded in the deferral account on a straight line basis over a period not to exceed three years, to the extent that the OEB is satisfied that the revenue requirement impacts are accurately recorded.

7 Short-Term Credit Facilities

OPG's $1 billion revolving committed bank credit facility is divided into two tranches – a $500 million 364-day term tranche maturing May 22, 2007, and a $500 million three-year term tranche maturing May 22, 2009. The total credit facility will be used primarily as support for notes issued under OPG's commercial paper program. As of December 31, 2006, there was $15 million of commercial paper outstanding (2005 – $ nil). OPG had no other outstanding borrowing under its bank credit facility in 2006 and 2005.

OPG also maintains $26 million (2005 – $26 million) in short-term uncommitted overdraft facilities as well as $240 million (2005 – $215 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support the supplementary pension plans and is required to post Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At December 31, 2006, there was a total of $185 million (2005 – $157 million) of Letters of Credit issued, which included $159 million relating to the supplementary pension plans (2005 – $138 million) and $16 million (2005 – $ nil) relating to the construction of the Portlands Energy Centre.

8 Long-Term Debt

Long-term debt consists of the following:

(millions of dollars)	**2006**	2005
Notes payable to the OEFC	**3,165**	3,695
Share of non-recourse limited partnership debt	**194**	200
	3,359	3,895
Less: due within one year		
Notes payable to the OEFC	**400**	800
Share of limited partnership debt	**6**	6
	406	806
Long-term debt	**2,953**	3,089

Holders of the senior debt are entitled to receive, in full, amounts owing in respect of the senior debt before holders of the subordinated debt are entitled to receive any payments. The OEFC currently holds all of OPG's outstanding senior and subordinated notes.

The maturity dates as at December 31, 2006 for notes payable to the OEFC are as follows:

(millions of dollars)		Principal Outstanding		
Year of Maturity	Interest Rate (%)	Senior Notes	Subordinated Notes	Total
2007	5.85	400	–	400
2008	5.90	400	–	400
2009	6.01	350	–	350
2010	6.00	595	375	970
2011	6.65	–	375	375
2012	5.72	400	–	400
2016	4.91	270	–	270
		2,415	750	3,165

In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to $600 million until March 31, 2006. In April 2005, $400 million was drawn under this facility, with a seven-year term.

In September 2005, OPG reached an agreement with the OEFC to provide debt financing for the Niagara Tunnel project. The funding, which is up to $1 billion over the duration of the project, will be in the form of 10-year notes, which will be issued quarterly to meet the project's obligations. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. In October 2006, OPG issued $160 million against this facility.

In October 2005, OPG reached a similar agreement with the OEFC to provide debt financing for the Thunder Bay Gas Conversion project. Under this credit facility, up to $95 million was available to OPG and could be drawn as needed over the construction period. In light of the directive to the OPA to determine how best to replace coal-fired generation, the Province determined that it was no longer advisable to continue with the conversion of the Thunder Bay generating station to run on natural gas. On July 12, 2006, OPG received a Shareholder Declaration revoking the October 2005 Shareholder Declaration, effectively cancelling the project.

In December 2006, OPG reached an agreement with the OEFC to provide debt financing for the Lac Seul Hydroelectric Generating Station and the Portlands Energy Centre projects. There will be up to $50 million available for the Lac Seul project and up to $400 million available for the Portlands Energy Centre project under each credit facility. The credit facilities will be drawn as needed to fund the respective projects over the construction period. The funding will be in the form of 10-year notes with interest rates fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. In December 2006, OPG issued $20 million and $90 million against the Lac Seul project credit facility and the Portlands Energy Centre credit facility respectively.

Interest paid in 2006 was $248 million (2005 – $235 million), of which $229 million relates to interest paid on long-term debt (2005 – $220 million).

9 Fixed Asset Removal and Nuclear Waste Management

The liabilities for fixed asset removal and nuclear waste management on a present value basis consist of the following:

(millions of dollars)	**2006**	2005
Liability for nuclear used fuel management	**5,669**	4,940
Liability for nuclear decommissioning and low and intermediate level waste management	**4,659**	3,627
Liability for non-nuclear fixed asset removal	**192**	192
Fixed asset removal and nuclear waste management liabilities	**10,520**	8,759

The changes in the fixed asset removal and nuclear waste management liability for the years ended December 31, 2006 and 2005 are as follows:

(millions of dollars)	**2006**	2005
Liabilities, beginning of year	**8,759**	8,339
Increase in liabilities due to accretion	**499**	476
Increase in liabilities due to nuclear used fuel and nuclear waste management variable expenses	**38**	34
Liabilities settled by expenditures on waste management	**(164)**	(90)
Increase in the liability for non-nuclear fixed asset removal	**2**	–
Increase in the liability for nuclear used fuel management and the liability for nuclear decommissioning and low and intermediate level waste management to reflect the change in cost estimates	**1,386**	–
Liabilities, end of year	**10,520**	8,759

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and upon termination of operations and the closure of nuclear and fossil-fuelled generating plant facilities. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and fossil-fuelled production facilities at the end of their useful lives;
- The present value of the fixed cost portion of any nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations;
- The present value of the variable cost portion of any nuclear waste management program to take into account actual waste volumes incurred to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. As at December 31, 2006, OPG updated the estimates for the nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management liabilities. The resulting updated Reference Plan ("2006 Approved Reference Plan") was approved by the Province in accordance with the terms of the ONFA. The increase in cost estimates reflected in the Approved Reference Plan is mainly due to additional used fuel and waste quantities resulting from station life extension, recent experience in decommissioning reactors, and changes in economic indices. The increase is partially offset by the deferral of some station decommissioning dates.

As a result of the approval of the new Reference Plan, OPG will recognize additional expenses including accretion on the fixed asset removal and nuclear waste management liabilities and depreciation of the carrying value of the related fixed assets. The impact of these additional expenses will be reduced by the recognition of a regulatory asset to be recovered through future prices charged to customers, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) discussed in Note 6 to the consolidated financial statements.

Nuclear and fossil-fuelled plant closures are projected to occur over the next six to 33 years. The updated Reference Plan includes cash flow estimates to 2073 for decommissioning nuclear stations and to approximately 2159 for nuclear used fuel management. The undiscounted amount of estimated cash flows associated with the liabilities expected to be incurred up to and upon closure of generating stations is approximately $24 billion. The discount rate used to calculate the present value of the liabilities was 5.75 per cent for liabilities established prior to December 31, 2006. The upward revision in the amount of the undiscounted estimated cash flows for OPG's liability for nuclear waste management and decommissioning was discounted at 4.6 per cent. The cost escalation rates ranged from 1.8 per cent to 3.6 per cent. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The current assumptions that have been used to establish the accrued used fuel costs include long-term management of the spent fuel bundles through deep geological disposal; an in-service date of 2035 for used nuclear fuel disposal facilities; and an average transportation distance of 1,000 kilometres between nuclear generating facilities and the disposal facilities. Alternatives to deep geological disposal have been studied by Canadian nuclear utilities via the Nuclear Waste Management Organization as part of the options study required by the federal *Nuclear Fuel Waste Act* (Canada) ("NFWA"). The options study was submitted to the federal government in November 2005. The federal government will decide which management alternative should be followed. The pending decision could have a significant impact on OPG's estimate of the liability.

Liability for Nuclear Decommissioning and Low and Intermediate Level Waste Management Costs

The liability for nuclear decommissioning and low and intermediate level waste management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis where the reactors will remain in a safe storage state for a 30-year period prior to a 10-year dismantlement period.

The life cycle costs of low and intermediate level waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term disposal of these wastes. The current assumptions used to establish the accrued low and intermediate level waste management costs include a disposal facility for low and intermediate level waste with an in-service date of 2017. The option has been approved by the Municipality of Kincardine and the Environmental Assessment ("EA") process is now underway.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal is based on third-party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. This liability represents the estimated costs of decommissioning fossil-fuelled generating stations at the end of their service lives. The estimated retirement date of these stations is between 2012 and 2039.

In addition to the $103 million liability for active sites, OPG also has an asset retirement obligation liability of $89 million for decommissioning and restoration costs associated with plant sites that have been divested or are no longer in use.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities. Also, the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Ontario Nuclear Funds Agreement

OPG sets aside funds to be used specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In July 2003, OPG and the Province completed arrangements, pursuant to the ONFA. To comply with the ONFA, OPG established the Nuclear Funds. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund will be used to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. The initial funding of the Decommissioning Fund was intended to be sufficient to fully discharge the 1999 estimate of the liability. OPG bears the risk and liability for cost estimate increases and fund earnings in the Decommissioning Fund.

The Used Fuel Fund will be used to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability for cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $6.0 billion, a present value amount at April 1, 1999 (approximately $9.1 billion in 2006 dollars) based on used fuel bundle projections of 2.23 million bundles consistent with the station lives included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles as projected in the 2006 Approved ONFA Reference Plan. OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2006 under the ONFA was $454 million, including a contribution to The Ontario NFWA Trust (the "Trust") of $50 million.

The NFWA was proclaimed into force in November 2002. In accordance with the NFWA, the Nuclear Waste Management Organization was formed to prepare and review alternatives, and to provide recommendations to the federal government for long-term management of nuclear fuel waste by November 2005. The federal government will select the option for dealing with the long-term management of nuclear fuel waste based on submitted plans. As required under the NFWA, OPG made an initial deposit of $500 million into the Trust in November 2002. The NFWA also requires OPG to make annual contributions of $100 million to the Trust, to be deposited into the Trust no later than the November anniversary of the NFWA. To comply with this requirement, OPG contributed $150 million to the Trust in 2005 ($50 million of the funding was part of OPG's funding requirement for 2006), and $50 million in 2006 to complete the 2006 funding requirement. Under the NFWA, OPG must continue to deposit $100 million annually into the Trust until the federal government has approved a long-term plan. Future contributions to the Trust beyond 2006 will be dependent on the direction chosen by the federal government based on the recommendations submitted in November 2005. Given that the Trust forms part of the Used Fuel Fund, contributions to the Trust, as required by the NFWA, are applied towards the ONFA payment obligations.

As required by the *Nuclear Safety and Control Act* (Canada), and under the terms of the ONFA, the Province issued a guarantee to the Canadian Nuclear Safety Commission ("CNSC"), on behalf of OPG, for up to $1,510 million. This is a guarantee that there will be sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The provincial guarantee will supplement the Used Fuel Fund and the Decommissioning Fund until they have accumulated sufficient funds to cover the accumulated liabilities for nuclear decommissioning and waste management. The guarantee, taken together with the Used Fuel Fund and Decommissioning Fund, was in satisfaction of OPG's nuclear licensing requirements with the CNSC. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount guaranteed by the Province. OPG paid the annual guarantee fee for 2006 of $8 million (2005 – $8 million).

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return"), but only for the Used Fuel Fund relating to the liability associated with the first 2.23 million used fuel bundles. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of fund assets, which includes realized and unrealized returns, is due to or due from the Province. Since OPG accounts, up to December 31, 2006, for the investments in the segregated funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At December 31, 2006, the Used Fuel Fund accounts included an amount due to the Province of $100 million (2005 – $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the consolidated financial statements, at December 31, 2006, there would be an amount due to the Province of $641 million (2005 – $306 million).

Under the ONFA, the Decommissioning Fund had a long-term target rate of return of 5.75 per cent per annum. Under the 2006 Approved Reference Plan, the rate was revised to 5.15 per cent. The target rate of return is subject to future changes in the ONFA Reference Plan. If the rate of return deviates from 5.15 per cent, or if the estimate of the liabilities changes under the current approved ONFA Reference Plan, the Decommissioning Fund may become over or underfunded. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the Current Approved ONFA Reference Plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent as a contribution to the Used Fuel Fund, and the OEFC is entitled to a distribution of an equal amount. In addition, upon termination of the ONFA, the Province has a right to any excess funds, which is the extent to which the fair market value of the Decommissioning Fund exceeds the estimated completion costs approved under the Current Approved ONFA Reference Plan. As at December 31, 2006, the Decommissioning Fund became underfunded on an amortized cost basis as a result of the approval of the 2006 Approved ONFA Reference Plan. Accordingly, no excess adjustment was reported in the Decommissioning Fund as at December 31, 2006. At December 31, 2005, the Decommissioning Fund exceeded the estimated completion cost under the previous ONFA Reference Plan approved in 1999 on an amortized cost basis. OPG reported an excess of $7 million due to the Province on an amortized cost basis in 2005. If the investments in the Decommissioning Fund were accounted for at fair market value in the consolidated financial statements at December 31, 2006, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $294 million (2005 – $484 million).

The nuclear fixed asset removal and nuclear waste management funds as at December 31, 2006 and 2005, consist of the following:

	Amortized Cost Basis		Fair Value	
(millions of dollars)	**2006**	2005	**2006**	2005
Decommissioning Fund	**4,356**	4,106	**5,169**	4,583
Due to Province – Decommissioning Fund	**–**	(7)	**(294)**	(484)
	4,356	4,099	**4,875**	4,099
Used Fuel Fund[1]	**3,338**	2,693	**3,879**	2,995
Due to Province – Used Fuel Fund	**(100)**	(4)	**(641)**	(306)
	3,238	2,689	**3,238**	2,689
	7,594	6,788	**8,113**	6,788

1 The Ontario NFWA Trust represents $1,102 million as at December 31, 2006 (December 31, 2005 – $1,003 million) of the Used Fuel Fund on an amortized cost basis.

The amortized cost and fair value of the securities invested in the segregated funds, which include the Used Fuel Fund and Decommissioning Fund, as at December 31, 2006 and 2005 are as follows:

	Amortized Cost Basis		Fair Value	
(millions of dollars)	**2006**	2005	**2006**	2005
Cash and cash equivalents and short-term investments	**556**	516	**553**	515
Marketable equity securities	**4,250**	3,772	**5,608**	4,547
Bonds and debentures	**2,306**	1,757	**2,305**	1,762
Receivable from the OEFC	**588**	759	**588**	759
Administrative expense payable	**(6)**	(5)	**(6)**	(5)
	7,694	6,799	**9,048**	7,578
Due to Province – Decommissioning Fund	**–**	(7)	**(294)**	(484)
Due to Province – Used Fuel Fund	**(100)**	(4)	**(641)**	(306)
Total	**7,594**	6,788	**8,113**	6,788

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31, 2006 and 2005 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2006**	2005
Less than 1 year	**–**	–
1 – 5 years	**1,167**	769
5 – 10 years	**467**	485
More than 10 years	**671**	508
Total maturities of debt securities	**2,305**	1,762
Average yield	**4.5%**	4.3%

The receivable of $588 million (2005 – $759 million) from the OEFC does not have a specified maturity date. The effective rate of interest on the OEFC receivable was 3.9 per cent in 2006 (2005 – 5.8 per cent).

The change in the Nuclear Funds for the years ended December 31, 2006 and 2005 are as follows:

	Amortized Cost Basis		Fair Value	
(millions of dollars)	**2006**	2005	**2006**	2005
Decommissioning Fund, beginning of year	**4,099**	3,858	**4,099**	3,882
Increase in fund due to return on investments	**256**	255	**592**	459
Decrease in fund due to reimbursement of expenditures	**(6)**	(7)	**(6)**	(7)
Decrease (increase) in Due to Province	**7**	(7)	**190**	(235)
Decommissioning Fund, end of year	**4,356**	4,099	**4,875**	4,099
Used Fuel Fund, beginning of year	**2,689**	2,118	**2,689**	2,118
Increase in fund due to contributions made	**454**	454	**454**	454
Increase in fund due to return on investments	**204**	133	**443**	283
Decrease in fund due to reimbursement of expenditures	**(13)**	(16)	**(13)**	(16)
(Increase) decrease in Due to Province	**(96)**	–	**(335)**	(150)
Used Fuel Fund, end of year	**3,238**	2,689	**3,238**	2,689

10 Income Taxes

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that the future income taxes are expected to be recovered in future regulated prices charged to customers. As part of the transition, on April 1, 2005, OPG reversed the net future income tax asset balance of $74 million relating to the rate regulated segments of its business, and recognized the amount as an extraordinary loss in determining net income. The extraordinary item reduced basic and diluted earnings per share for the year ended December 31, 2005 by $0.29 per share.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2006**	2005
Income before income taxes	**576**	558
Combined Canadian federal and provincial statutory income tax rates, including surtax	**36.1%**	36.1%
Statutory income tax rates applied to accounting income	**208**	202
Increase (decrease) in income taxes resulting from:		
Large corporations tax in excess of surtax	**–**	28
Lower future tax rate on temporary differences	**(4)**	(12)
Non-taxable income items	**(5)**	7
Unrecorded future income tax related to regulated operations	**(89)**	(157)
Change in income tax positions	**10**	50
Other changes in future tax rate	**(34)**	–
	(122)	(84)
Income tax expense	**86**	118
Effective rate of income taxes	**14.9%**	21.1%

The Company has revised its future income tax assets and liabilities to reflect the lower federal income tax rates recently enacted.

In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors ("Tax Auditors") with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998*. OPG has estimated that the proposed adjustments could result in additional taxes payable for the 1999 taxation year in excess of $200 million. Although OPG has subsequently resolved some of these issues, there is uncertainty as to how the remaining issues will be resolved.

OPG expects to receive a reassessment for its 1999 taxation year. The Company would defend its position through the tax appeals process. The potential increase in taxes payable related to these issues for 1999 and subsequent taxation years could be material. Because OPG uses the taxes payable method to account for income taxes in the regulated business segments and the liability method for the unregulated business segments, the impact of any potential adjustments on future income tax expense could vary significantly, depending on the resolution of these issues.

OPG has previously recorded income tax charges related to certain income tax positions that the Company has taken in prior years that may be disallowed. Given the uncertainty as to how these income tax matters will be resolved, OPG has not adjusted its income tax liabilities. Should the ultimate outcome materially differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its earnings could be affected positively or negatively in the period in which the matters are resolved.

Significant components of the provision for income tax expense are presented in the table below:

(millions of dollars)	**2006**	2005
Current income tax expense	**60**	80
Future income tax expense (benefits):		
Change in temporary differences	**–**	(51)
Non-capital loss carry-forward	**52**	88
Other	**(26)**	1
	26	38
Income tax expense	**86**	118

The income tax effects of temporary differences that give rise to future income tax assets and liabilities are presented in the table below:

(millions of dollars)	**2006**	2005
Future income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**29**	27
Other liabilities and assets	**107**	107
Non-capital loss carry-forward	**28**	98
Future recoverable Ontario minimum tax	**64**	37
	228	269
Future income tax liabilities:		
Fixed assets	**332**	351
Other liabilities and assets	**145**	141
	477	492
Net future income tax liabilities	**249**	223
Represented by:		
Current portion liability (asset)	**3**	(18)
Long-term portion	**246**	241
	249	223

The following table summarizes the difference in the balance sheet amounts under the taxes payable method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business as at December 31, 2006 and 2005:

	2006		2005	
(millions of dollars)	**As Stated**	**Liability Method**[1]	As Stated	Liability Method[1]
Future income tax (liabilities) assets – current	**(3)**	**(4)**	18	38
Long-term future income tax liabilities	**(246)**	**(417)**	(241)	(344)

1 As discussed in note 3, OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. The related future income tax impact disclosed in note 3 is excluded from the above.

The following table summarizes the difference in the income statement amounts under the method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business for the years ended December 31, 2006 and 2005:

	2006		2005	
(millions of dollars)	**As Stated**	**Liability Method**[1]	As Stated	Liability Method[1]
Extraordinary item	**–**	**–**	74	–
Future income tax expense	**26**	**115**	38	195

1 As discussed in note 3, OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. The related future income tax impact disclosed in note 3 is excluded from the above.

As at December 31, 2006, OPG had available approximately $308 million (2005 – $236 million) of non-capital loss carry-forwards for Ontario income tax purposes. The non-capital loss carry-forward for the purpose of calculating Ontario income taxes is related to the following taxation years:

(millions of dollars)	Ontario Loss-Carry Forward	Expiry Date
2004	236	2014[1]
2006	72	2026

1 The Province of Ontario recently introduced legislation in anticipation of the Ontario Corporate tax harmonization whereby these losses would be replaced by a special tax credit which would expire in 2011.

The amount of cash income taxes paid during 2006 was $24 million (2005 – $20 million).

11 Benefit Plans

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. The registered pension plan is a contributory defined benefit plan covering most employees and retirees. Pension fund assets include equity securities and corporate and government debt securities, real estate and other investments which are managed by professional investment managers. The fund does not invest in equity or debt securities issued by OPG. The supplementary pension plans are defined benefit plans covering certain employees and retirees.

Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The pension and OPEB obligations, and the pension fund assets, are measured at December 31, 2006.

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2006	2005	**2006**	2005
Weighted Average Assumptions – Benefit Obligation at Year End				
Rate used to discount future benefits	**5.25%**	5.00%	**5.22%**	4.97%
Salary schedule escalation rate	**3.00%**	3.00%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.00%	**–**	–
Initial health care trend rate	**–**	–	**7.34%**	7.76%
Ultimate health care trend rate	**–**	–	**4.68%**	4.68%
Year ultimate rate reached	**–**	–	**2014**	2014
Rate of increase in disability benefits	**–**	–	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2006	2005	**2006**	2005
Weighted Average Assumptions – Cost for the Year				
Expected return on plan assets net of expenses	**7.00%**	7.00%	**–**	–
Rate used to discount future benefits	**5.00%**	6.00%	**4.97%**	5.88%
Salary schedule escalation rate	**3.00%**	3.25%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.25%	**–**	–
Initial health care trend rate	**–**	–	**7.76%**	7.03%
Ultimate health care trend rate	**–**	–	**4.68%**	4.46%
Year ultimate rate reached	**–**	–	**2014**	2014
Rate of increase in disability benefits	**–**	–	**2.00%**	2.25%
Average remaining service life for employees (years)	**11**	11	**11**	11

(millions of dollars)	Registered Pension Plans 2006	2005	Supplementary Pension Plans 2006	2005	Other Post Employment Benefits 2006	2005
Changes in Plan Assets						
Fair value of plan assets at beginning of year	**7,921**	7,056	**–**	–	**–**	–
Contributions by employer	**261**	254	**7**	7	**62**	58
Contributions by employees	**61**	56	**–**	–	**–**	–
Actual return on plan assets net of expenses	**945**	858	**–**	–	**–**	–
Settlements	**–**	(2)	**–**	–	**–**	–
Benefit payments	**(359)**	(301)	**(7)**	(7)	**(62)**	(58)
Fair value of plan assets at end of year	**8,829**	7,921	**–**	–	**–**	–
Changes in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	**9,095**	7,663	**144**	144	**2,065**	1,499
Employer current service costs	**212**	163	**6**	7	**71**	47
Contributions by employees	**61**	56	**–**	–	**–**	–
Interest on projected benefit obligation	**459**	461	**7**	9	**104**	88
Past service costs	**–**	–	**–**	–	**13**	1
Settlement gain	**–**	(2)	**–**	–	**–**	–
Benefit payments	**(359)**	(301)	**(7)**	(7)	**(62)**	(58)
Net actuarial loss (gain)	**(155)**	1,055	**2**	(9)	**(124)**	488
Projected benefit obligation at end of year	**9,313**	9,095	**152**	144	**2,067**	2,065
Funded Status – Deficit at end of year	**(484)**	(1,174)	**(152)**	(144)	**(2,067)**	(2,065)

The assets of the OPG pension fund are allocated among three principal investment categories. Furthermore, equity investments are diversified across Canadian, U.S. and non-North American stocks. The fund also has a small real estate portfolio that is less than one per cent of plan assets.

	2006	2005
Registered pension plan fund asset investment categories		
Equities	**67%**	64%
Fixed income	**30%**	33%
Cash and short-term	**3%**	3%
Total	**100%**	100%

Based on the most recently filed actuarial valuation, as at January 1, 2005, there was an unfunded liability on a going-concern basis of $465 million and a deficiency on a wind-up basis of $1,979 million. The deficit disclosed in the next filed funding valuation, which must have an effective date no later than January 1, 2008, could be significantly different.

The supplementary plans are not funded, but are secured by Letters of Credit totalling $159 million (2005 – $138 million).

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2006**	2005	**2006**	2005	**2006**	2005
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)						
Funded status – deficit at end of year	**(484)**	(1,174)	**(152)**	(144)	**(2,067)**	(2,065)
Unamortized net actuarial loss	**1,108**	1,737	**20**	18	**699**	885
Unamortized past service costs	**82**	100	**3**	4	**25**	16
Accrued benefit asset (liability) at end of year	**706**	663	**(129)**	(122)	**(1,343)**	(1,164)
Short-term portion	**–**	–	**(6)**	(7)	**(70)**	(67)
Long-term portion	**706**	663	**(123)**	(115)	**(1,273)**	(1,097)

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2006**	2005	**2006**	2005	**2006**	2005
Components of Cost Recognized						
Current service costs	**212**	163	**6**	7	**71**	47
Interest on projected benefit obligation	**459**	461	**7**	9	**104**	88
Expected return on plan assets net of expenses	**(551)**	(527)	**–**	–	**–**	–
Amortization of past service costs	**18**	18	**1**	1	**4**	3
Amortization of net actuarial loss	**80**	–	**–**	1	**62**	25
Cost recognized	**218**	115	**14**	18	**241**	163

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2006**	2005	**2006**	2005	**2006**	2005
Components of Cost Incurred and Recognized						
Current service costs	**212**	163	**6**	7	**71**	47
Interest on projected benefit obligation	**459**	461	**7**	9	**104**	88
Actual return on plan assets net of expenses	**(945)**	(858)	**–**	–	**–**	–
Past service costs	**–**	–	**–**	–	**13**	1
Net actuarial loss (gain)	**(155)**	1,055	**2**	(9)	**(124)**	488
Cost incurred in year	**(429)**	821	**15**	7	**64**	624
Differences between costs incurred and recognized in respect of:						
Actual return on plan assets net of expenses	**394**	331	**–**	–	**–**	–
Past service costs	**18**	18	**1**	1	**(9)**	2
Net actuarial (gain) loss	**235**	(1,055)	**(2)**	10	**186**	(463)
Cost recognized	**218**	115	**14**	18	**241**	163

A one per cent increase or decrease in the health care trend rate would result in an increase in the service and interest components of the 2006 OPEB cost recognized of $34 million (2005 – $26 million) or a decrease in the service and interest components of the 2006 OPEB cost recognized of $26 million (2005 – $20 million), respectively. A one per cent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2006 of $342 million (2005 – $343 million) or a decrease in the projected OPEB obligation at December 31, 2006 of $265 million (2005 – $266 million).

12 Financial Instruments

Contracts for all trading transactions are carried on the consolidated balance sheet as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

Fair values of derivative instruments have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG considers various factors to estimate forward prices, including market prices and price volatility in neighbouring electricity markets, market prices for fuel, and other factors.

Forward pricing information is inherently uncertain so that fair values of the derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions. During 2006, the liquidity reserve increased trading revenue by $1 million (2005 – $4 million).

Derivative Instruments Used for Hedging Purposes

The following table provides the estimated fair value of derivative instruments designated as hedges. The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

(millions of dollars except where noted)	**Notional Quantity**	**Terms 2006**	**Fair Value**	Notional Quantity	Terms 2005	Fair Value
Gain (loss)						
Electricity derivative instruments	**4.3 TWh**	**1–4 yrs**	**51**	4.1 TWh	1–2 yrs	(125)
Foreign exchange derivative instruments	**U.S.$2**	**Jan/07**	**–**	U.S.$15	Jan/06	–
Floating to fixed interest rate hedges	**45**	**1–12 yrs**	**(3)**	47	1–13 yrs	(3)
Forward start interest rate hedges	**622**	**1–14 yrs**	**(9)**	400	1–15 yrs	(7)

Foreign exchange derivative instruments are used to hedge the exposure to anticipated U.S. dollar denominated purchases. The weighted average fixed exchange rate for contracts outstanding at December 31, 2006 was U.S.$0.87 (2005 – U.S.$0.87) for every Canadian dollar.

One of the Company's joint ventures is exposed to changes in interest rates. The joint venture entered into an interest rate swap to manage the risk arising from fluctuations in interest rates by swapping the short-term floating interest rate with a fixed rate of 5.33 per cent. OPG's proportionate interest in the swap is 50 per cent and is accounted for as a hedge.

OPG entered into a number of forward start interest rate swap agreements to hedge against the effect of future interest rate movement based on the anticipated future borrowing requirement for the Niagara Tunnel and the Portlands Energy Centre projects. These transactions are accounted for as hedges.

Derivative Instruments Not Used for Hedging Purposes

The carrying amount (fair value) of derivative instruments not designated for hedging purposes is as follows:

(millions of dollars except where noted)	**Notional Quantity 2006**	**Fair Value 2006**	Notional Quantity 2005	Fair Value 2005
Foreign exchange derivative	**–**	**–**	U.S.$3	–
Commodity derivative instruments				
Assets	**3.9 TWh**	**25**	3.3 TWh	13
Liabilities	**2.6 TWh**	**(25)**	1.1 TWh	(37)
		–		(24)
Liquidity reserve		**(2)**		(3)
Total		**(2)**		(27)

Foreign exchange derivative instruments that were not designated as hedges had a weighted average exchange rate of U.S.$0.85 as at December 31, 2005.

Fair Value of Other Financial Instruments

The carrying values of cash and cash equivalents, accounts receivable, accounts payable and accrued charges, Market Power Mitigation Agreement rebate payable, and short-term notes payable approximate their fair values due to the immediate or short-term maturity of these financial instruments. Fair values for other financial instruments have been estimated by reference to quoted market prices for actual or similar instruments where available.

The carrying values and fair values of these other financial instruments are as follows:

(millions of dollars)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
	2006		2005	
Financial Assets				
Nuclear fixed asset removal and nuclear waste management funds	**7,594**	**8,113**	6,788	6,788
Long-term accounts receivable and other assets	**69**	**69**	61	61
Financial Liabilities				
Long-term debt due within one year	**406**	**409**	806	814
Long-term debt	**2,953**	**3,082**	3,089	3,267
Long-term accounts payable and accrued charges	**150**	**150**	183	183

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. The majority of OPG revenues are derived from sales through the IESO administered spot market. However, OPG also derives revenue from several other sources including the sale of energy products and financial risk management products to third parties.

Credit exposure to the IESO fluctuates based on spot prices and the volume of rate regulated and unregulated generation, and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at $1,029 million during the year ended December 31, 2006 and at $1,146 million during the year ended December 31, 2005.

13 Common Shares

As at December 31, 2006 and 2005, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value.

14 Commitments and Contingencies

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities.

In July 2004, OPG and two individual OPG employees were each charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 drowning accident at Barrett Chute. Further to a recent summary application by all three, OPG was acquitted of all charges on November 14, 2006. On December 18, 2006, the two employees were acquitted of all the remaining charges. The appeal period expired on January 18, 2007. Since no appeal was filed, the acquittals of OPG and its employees are considered final.

Certain First Nations have commenced actions for interference with reserve and traditional land rights. The claims by some of these First Nations total approximately $50 million and claims by others are for unspecified amounts.

On August 9, 2006, a Notice of Action and Statement of Claim in the amount of $500 million (the "Claim") was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited ("British Energy"), claiming that OPG is liable to them for breach of contract and negligence. OPG leased the Bruce nuclear generating stations to Bruce Power L.P. in 2001. British Energy was an investor in Bruce Power L.P. In 2003, British Energy sold its interest in Bruce Power L.P. to a group of investors (the "Purchasers"). The Purchasers are claiming that British Energy is liable to them with respect to this purchase transaction. Their claim is currently the subject of an arbitration proceeding (the "Arbitration"). British Energy is therefore suing OPG in order to preserve any similar claim it may have against OPG pursuant to the 2001 lease transaction. British Energy has indicated that it does not require OPG to actively defend the Claim at this point in time as British Energy is defending the Arbitration commenced by the Purchasers. The Arbitration may narrow or eliminate the claims or damages British Energy has, so as to narrow or eliminate the need to continue the Claim against OPG. British Energy has reserved the right to require OPG to defend the Claim prior to the conclusion of the Arbitration should British Energy at some point believe there is some advantage of doing so.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG and could have a significant effect on OPG's financial position. Management has provided for contingencies that are determined to be likely and are reasonably measurable.

Environmental

OPG was required to assume certain environmental obligations from Ontario Hydro. A provision of $76 million was established as at April 1, 1999 for such obligations. During the year ended December 31, 2006, expenditures of $4 million (2005 – $4 million) were recorded against the provision. As at December 31, 2006, the remaining provision was $52 million (December 31, 2005 – $56 million).

Current operations are subject to regulation with respect to air, soil and water quality and other environmental matters by federal, provincial and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its consolidated financial statements to meet OPG's current environmental obligations.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, standby Letters of Credit and surety bonds.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2006 are as follows:

(millions of dollars)	2007	2008	2009	2010	2011	Thereafter	**Total**
Contractual obligations:							
Fuel supply agreements	670	514	202	153	167	351	**2,057**
Contributions under the ONFA[1]	454	679	350	350	350	1,053	**3,236**
Long-term debt repayment	400	400	350	970	375	670	**3,165**
Interest on long-term debt	181	158	135	103	55	80	**712**
Unconditional purchase obligations	25	20	17	15	12	194	**283**
Long-term accounts payable	28	9	–	–	–	–	**37**
Operating lease obligations	10	9	11	10	10	123	**173**
Operating licence	16	17	17	17	18	–	**85**
Pension contributions[2]	268	–	–	–	–	–	**268**
Other	144	30	26	28	24	26	**278**
Significant commercial commitments:							
Niagara Tunnel	167	178	132	2	–	–	**479**
Lac Seul	24	–	–	–	–	–	**24**
Portlands Energy Centre	155	63	22	2	1	24	**267**
Total	2,542	2,077	1,262	1,650	1,012	2,521	**11,064**

1 Contributions under the ONFA are subject to adjustment due to the 2006 Approved Reference Plan.

2 The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuation as at January 1, 2005, as well as a voluntary contribution of approximately $20 million. The contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, and the timing of funding valuations. Funding requirements after 2007 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

The Niagara Tunnel project will increase the amount of water flowing to existing turbines at OPG's Sir Adam Beck generating stations in Niagara, allowing the stations to utilize available water more effectively. On-site assembly of the tunnel boring machine was completed in September 2006 and boring of the tunnel commenced during the month. The intake configuration required the replacement of the existing accelerating wall and the installation of a cellular cofferdam, which were completed in 2006. Capital project expenditures for the year ended December 31, 2006 were $161 million and life-to-date capital expenditures were approximately $244 million. The project is debt financed through the OEFC.

OPG is constructing a new 12.5 MW hydroelectric generating station on the English River. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded and construction started during the first quarter of 2006. In 2006, the water conveyance tunnel, the tailrace channel excavation, and the intake cofferdam were completed. The powerhouse civil foundation and envelope was completed in January 2007. Major sub-assemblies have been delivered to the site and pre-installation work has started. Capital project expenditures for the year ended December 31, 2006 were approximately $24 million and life-to-date capital expenditures were approximately $27 million. OPG has negotiated the project's debt financing with the OEFC.

OPG entered into a partnership with TransCanada Energy Ltd. ("TransCanada"), called Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle station on the site of the former R.L. Hearn generating station, near downtown Toronto. During the first quarter of 2006, the Province directed the OPA to negotiate an agreement with PEC for the purchase of electricity. PEC signed a 20-year Accelerated Clean Energy Supply ("ACES") contract with the OPA during the third quarter of 2006. PEC entered into a design-build contract for the construction of the facility, and construction started in 2006. A significant proportion of the capital cost relates to this contract. OPG's share of capital project expenditures for the year ended December 31, 2006 was approximately $97 million. OPG has negotiated financing for its share of the project with the OEFC.

Other Commitments
In addition to the above commitments, the Company has the following commitments:

The Company maintains labour agreements with the Power Workers' Union and The Society of Energy Professionals; the agreements are effective until March 31, 2009 and December 31, 2010, respectively. As of December 31, 2006, OPG had approximately 11,500 regular employees and approximately 90 per cent of its regular labour force is covered by the collective bargaining agreements.

Contractual and commercial commitments above exclude certain purchase orders as they represent purchase authorizations rather than legally binding contracts and are subject to change without significant penalties.

Proxy Property Taxes
In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. OPG continues to discuss resolution to this issue with the Ministry of Finance as updates to the regulation may not occur for several years. OPG has not recorded any amounts relating to this anticipated regulation change.

15 Transition Rate Option Contracts

Under a regulation known as Transition – Generation Corporation Designated Rate Options ("TRO"), OPG was required to provide transitional price relief since market opening to certain power customers for up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The TRO was treated as a hedge of generation revenue. The maximum anticipated volume subject to the transitional price relief was approximately 5.4 TWh in the first year after market opening and 3.6 TWh in the second year. The maximum anticipated volume in each of the third and fourth years is 1.8 TWh. The maximum length of the program was four years, which expired April 30, 2006.

The change in the TRO contracts provision for the years ended December 31, 2006 and 2005 is as follows:

(millions of dollars)	**2006**	2005
Provision, beginning of year	**12**	48
Decrease of provision during the year	**(12)**	(36)
Provision, end of year	**–**	12

16 Revenue Limit Rebate

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets is also excluded from the output covered by the revenue limit. In addition, until the TRO contracts expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate.

The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning May 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these two revenue limits are returned to the IESO for the benefit of consumers.

The changes in the revenue limit rebate liability for the years ended December 31, 2006 and 2005 are as follows:

(millions of dollars)	**2006**	2005
Liability, beginning of the year	**739**	–
Increase to provision during the year	**161**	739
Payments made during the year	**(860)**	–
Liability, end of year	**40**	739

17 Market Power Mitigation Agreement Rebate

Until April 1, 2005, OPG was required under its generating licence to comply with prescribed market power mitigation measures to address the potential for OPG to exercise market power in Ontario. The market power mitigation measures included both a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, a majority of OPG's expected energy sales in Ontario were subject to an average annual revenue cap of 3.8¢/kWh. During the term of the Market Power Mitigation Agreement, OPG was required to pay a rebate to the Independent Electricity System Operator equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a 12-month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The Market Power Mitigation Agreement was replaced effective April 1, 2005 by regulated prices for the output from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities operated by OPG, and a revenue limit that applies to OPG's unregulated generation assets.

In accordance with the Market Power Mitigation Agreement, the rebate was calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the three months ended March 31, 2005, when the rebate mechanism ended, exceeded the 3.8¢/kWh revenue cap, OPG provided $412 million in 2005 as a Market Power Mitigation Agreement rebate.

The change in the Market Power Mitigation Agreement rebate liability for the year ended December 31, 2005 is as follows:

(millions of dollars)	2005
Liability, beginning of year	439
Increase to provision during the year	412
Payments	(851)
Liability, end of year	–

18 Business Segments

With the introduction of rate regulation effective April 1, 2005, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. In the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified to reflect the revised disclosure.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that OPG owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations.

OPG's Regulated – Nuclear business segment includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. The arrangement includes lease revenue, interest income and revenue from engineering analysis and design, technical and other services. The Regulated – Nuclear business segment also includes revenue earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support. These earnings are included in the Regulated – Nuclear business segment since they were included in determining the regulated price for production from the nuclear facilities operated by OPG.

Bruce Nuclear Generating Stations

In May 2001, the Company leased its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with options to renew for up to 25 years.

Under the terms of the lease, OPG agreed to transfer certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. Pension assets and liabilities related to the approximately 3,000 employees were transferred to Bruce Power. Bruce Power assumed the liability for other post employment benefits for these employees. OPG makes payments to Bruce Power in respect of other post employment benefits of approximately $2.3 million per month over a 72-month period, ending in 2008.

As part of the closing, OPG recorded deferred revenue to reflect the initial payments of $595 million less net assets transferred to Bruce Power under the lease agreement. The deferred revenue is being amortized over the initial lease term of approximately 18 years and is recorded as revenue.

In December 2002, British Energy plc. entered into an agreement to dispose of its entire 82.4 per cent interest in Bruce Power. The transaction was completed in February 2003 and a consortium of Canadian companies assumed the lease of the Bruce A and Bruce B nuclear generating stations that was formerly held by British Energy plc. The Bruce facilities will continue to be operated by Bruce Power. Upon closing of the transaction, the $225 million note receivable was paid to OPG, and lease payments commenced to be paid monthly. Proceeds from the note are to be applied by March 2008 against OPG's funding requirements with respect to the nuclear fixed asset removal and nuclear waste management liabilities.

As part of the agreement reached in October 2005 between the Province and Bruce Power, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to accept certain amendments to the lease agreement. These amendments included a change to the provisions regarding the transfer of Bruce Power's interest in the site and included a reduction of the annual lease payment for three of the four refurbished Bruce A units to $5.5 million per unit (in 2002 dollars, escalated at CPI), that will affect the three Bruce A units to be refurbished, once the planned future refurbishments are completed. These changes to the lease agreement will affect OPG when Units 1 and 2 of the Bruce A nuclear generating station are returned to service, and when Unit 3 is refurbished at the end of its current operational life. Other changes to the existing arrangements were made to address Cameco Corporation's decision not to participate in the refurbishment of the Bruce A nuclear generating station.

For 2004 through 2008, minimum payments under the lease are $190 million annually, subject to limited exceptions. The lease revenue of $251 million (2005 – $244 million) was recorded in revenue. The remaining terms of the operating lease agreement will remain substantially unchanged until the planned future refurbishments are completed.

The net book value of fixed assets on lease to Bruce Power at December 31, 2006 was $1,273 million (2005 – $492 million). The net book value at December 31, 2006 includes the impact of the increase in the nuclear fixed asset removal and nuclear waste management liabilities relating to the Bruce units as a result of the new Reference Plan described in Note 9.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of OPG's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – Hydroelectric business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, automatic generation control, and revenues from other services.

Other

OPG earns revenue from its joint venture share of the Brighton Beach related to an energy conversion agreement between Brighton Beach and Coral. In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

Operations, maintenance and administration ("OM&A") expenses of the generation business segments include an intersegment service fee for the use of certain property, plant and equipment of the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the year ended December 31, 2006, the service fee was $25 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric and $9 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $39 million for the Other category. Results of the comparative periods have been reclassified to reflect the service fee.

Segment Income (Loss) for the Year Ended December 31, 2006 (millions of dollars)	**Regulated**		**Unregulated**			
	Nuclear	**Hydro-electric**	**Hydro-electric**	**Fossil-Fuelled**	**Other**	**Total**
Revenue before revenue limit rebate	**2,665**	**685**	**780**	**1,430**	**165**	**5,725**
Revenue limit rebate	**–**	**–**	**(44)**	**(117)**	**–**	**(161)**
	2,665	**685**	**736**	**1,313**	**165**	**5,564**
Fuel expense	**122**	**245**	**88**	**643**	**–**	**1,098**
Gross margin	**2,543**	**440**	**648**	**670**	**165**	**4,466**
Operations, maintenance and administration	**1,967**	**92**	**189**	**524**	**5**	**2,777**
Depreciation and amortization	**343**	**66**	**69**	**133**	**53**	**664**
Accretion on fixed asset removal and nuclear waste management liabilities	**490**	**–**	**–**	**9**	**–**	**499**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(371)**	**–**	**–**	**–**	**–**	**(371)**
Property and capital taxes	**44**	**18**	**15**	**19**	**10**	**106**
Income (loss) before impairment of long-lived assets	**70**	**264**	**375**	**(15)**	**97**	**791**
Impairment of long-lived assets	**–**	**–**	**–**	**22**	**–**	**22**
Income (loss) before interest, income taxes and extraordinary item	**70**	**264**	**375**	**(37)**	**97**	**769**

Segment (Loss) Income for the Year Ended December 31, 2005 (millions of dollars)	Regulated		Unregulated			
	Nuclear	Hydro-electric	Hydro-electric	Fossil-Fuelled	Other	Total
Revenue before revenue limit and Market Power Mitigation Agreement rebates	2,607	857	1,000	2,399	86	6,949
Revenue limit rebate	–	–	(210)	(529)	–	(739)
Market Power Mitigation Agreement rebate	(160)	(65)	(58)	(129)	–	(412)
	2,447	792	732	1,741	86	5,798
Fuel expense	115	254	82	846	–	1,297
Gross margin	2,332	538	650	895	86	4,501
Operations, maintenance and administration	1,804	78	148	455	31	2,516
Depreciation and amortization	359	67	64	203	60	753
Accretion on fixed asset removal and nuclear waste management liabilities	467	–	–	9	–	476
Earnings on nuclear fixed asset removal and nuclear waste management funds	(381)	–	–	–	–	(381)
Property and capital taxes	30	18	15	39	5	107
Restructuring	–	–	–	4	6	10
Income (loss) before impairment of long-lived assets	53	375	423	185	(16)	1,020
Impairment of long-lived assets	63	–	–	202	–	265
(Loss) income before interest, income taxes and extraordinary item	(10)	375	423	(17)	(16)	755

(millions of dollars)	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
Selected Balance Sheet Information						
As at December 31, 2006						
Segment fixed assets in service, net	**4,213**	**3,907**	**3,012**	**408**	**544**	**12,084**
Segment construction work in progress	**165**	**252**	**78**	**49**	**133**	**677**
Segment property, plant and equipment, net	**4,378**	**4,159**	**3,090**	**457**	**677**	**12,761**
Segment materials and supplies inventory, net:						
Short term	**63**	**1**	**–**	**48**	**–**	**112**
Long term	**320**	**–**	**3**	**3**	**–**	**326**
Segment fuel inventory	**183**	**–**	**–**	**486**	**–**	**669**
As at December 31, 2005						
Segment fixed assets in service, net	3,016	3,963	3,031	484	570	11,064
Segment construction work in progress	140	91	45	47	25	348
Segment property, plant and equipment, net	3,156	4,054	3,076	531	595	11,412
Segment materials and supplies inventory, net:						
Short term	72	–	–	43	–	115
Long term	268	–	4	1	–	273
Segment fuel inventory	158	–	–	423	–	581
Selected Cash Flow Information						
Year ended December 31, 2006						
Investment in fixed assets	**173**	**171**	**81**	**71**	**141**	**637**
Year ended December 31, 2005						
Investment in fixed assets	273	101	44	46	30	494

19 Related Party Transactions

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

(millions of dollars)	**Revenue 2006**	**Expenses 2006**	Revenue 2005	Expenses 2005
Hydro One				
Electricity sales	**34**	**–**	40	–
Services	**–**	**13**	–	12
Settlement Transactions	**–**	**–**	–	27
Province of Ontario				
GRC water rentals and land tax	**–**	**132**	–	132
Guarantee fee	**–**	**8**	–	8
Used Fuel Fund rate of return guarantee	**–**	**96**	–	–
Decommissioning Fund excess funding	**–**	**(7)**	–	7
OEFC				
GRC and proxy property tax	**–**	**205**	–	207
Interest income on receivable	**–**	**(29)**	–	(75)
Interest expense on long-term notes	**–**	**203**	–	211
Capital tax	**–**	**51**	–	51
Income taxes	**–**	**86**	–	192
Indemnity fees	**–**	**2**	–	5
IESO				
Electricity sales	**5,029**	**146**	6,517	329
Market Power Mitigation Agreement rebate	**–**	**–**	(412)	–
Revenue limit rebate	**(161)**	**–**	(739)	–
Ancillary services	**132**	**–**	68	–
Other	**1**	**1**	–	–
	5,035	**907**	5,474	1,106

During 2006, OPG's Board of Directors approved the payment of a dividend to its shareholder, the Province. The declared dividend of $128 million represents 35 per cent of OPG's 2005 net income and was paid in November 2006.

At December 31, 2006, accounts receivable included $8 million (2005 – $14 million) due from Hydro One and $71 million (2005 – $324 million) due from the IESO. Accounts payable and accrued charges at December 31, 2006 included $2 million (2005 – $2 million) due to Hydro One.

20 Joint Ventures

Significant joint ventures include Brighton Beach and PEC, which are 50 per cent owned by OPG (2005 – 50 per cent).

The following condensed information from the consolidated statements of operations, cash flows and balance sheets detail the Company's share of its investment in joint ventures and partnerships that has been proportionately consolidated:

(millions of dollars)	**2006**	2005
Proportionate joint venture operations		
Operating revenue	**39**	46
Operating expenses	**(19)**	(36)
Net income	**20**	10
Proportionate joint venture cash flows		
Operating activities	**17**	21
Investing activities	**(109)**	(2)
Financing activities	**(6)**	(4)
Share of increase in cash	**(98)**	15
Proportionate joint venture balance sheets		
Current assets	**25**	26
Long-term assets	**379**	279
Current liabilities	**(25)**	(11)
Long-term liabilities	**(191)**	(199)
Share of net assets	**188**	95

21 Investment Company

The Company applied AcG-18 for all investments owned by OPGV. OPGV is a wholly owned subsidiary of the Company and its results are consolidated into the Company's financial statements. Since OPGV is the only enterprise in the group that satisfies the criteria set out in AcG-18, all other investments made by OPG and its subsidiaries, partnerships or joint ventures continue to be carried at amortized cost. The carrying amount of OPGV's investments was $32 million (2005 – $29 million) and the amount was included as long-term accounts receivable and other assets on the consolidated balance sheets.

As a result of the application of this policy, the Company's net income and other assets for 2006 increased by $2 million (2005 – decreased by $11 million). The net realized gains and losses for OPGV was $1 million (2005 – $nil).

The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2006 were $5 million and $14 million respectively. The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2005 were $2 million and $13 million respectively.

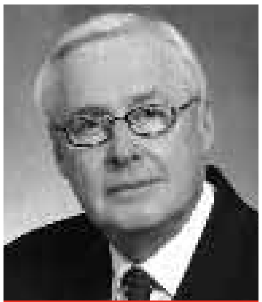
22 Research and Development

For the year ended December 31, 2006, $16 million (2005 – $19 million) of research and development expenses were charged to operations.

23 Changes in Non-Cash Working Capital Balances

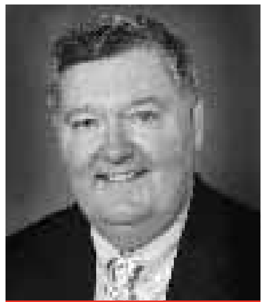
(millions of dollars)	**2006**	2005
Accounts receivable	**303**	(191)
Fuel inventory	**(88)**	(12)
Materials and supplies	**–**	(23)
Market Power Mitigation Agreement rebate payable	**–**	412
Revenue limit rebate payable	**161**	739
Accounts payable and accrued charges	**54**	10
Income and capital taxes payable	**47**	69
	477	1,004

Board of Directors[1]

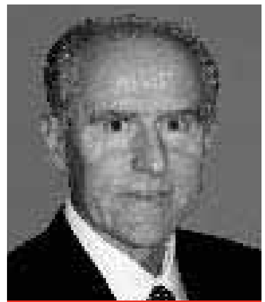


Jake Epp
Chairman

Jim Hankinson
President and CEO

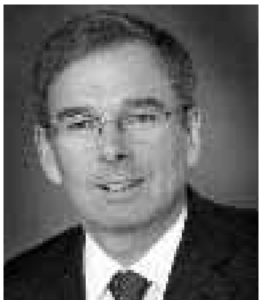


Donald Hintz
Retired President,
Entergy Corporation



Gary Kugler
Chairman,
Nuclear Waste
Management Organization

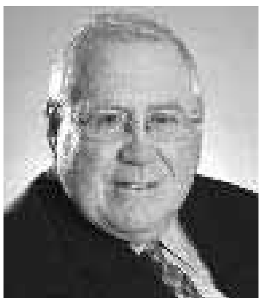
M. George Lewis
Chairman and CEO,
RBC Asset Management Inc.



David J. MacMillan
Corporate Director

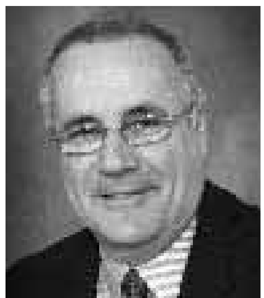
Corbin A. McNeill Jr.
Retired Chairman and
Co-Chief Executive Officer,
Exelon Corporation

Peggy Mulligan
Corporate Director



C. Ian Ross
Chairman,
GrowthWorks
Canadian Fund Ltd.

Marie C. Rounding
Counsel,
Gowling Lafleur
Henderson LLP



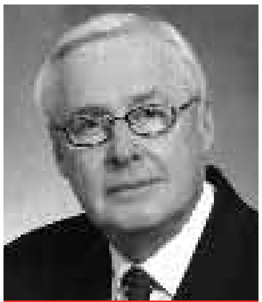
William (Bill) Sheffield
Corporate Director

David G. Unruh
Corporate Director

Audit/Risk Committee (ARC)[2]	Compensation and Human Resources Committee (CHRC)	Governance and Nominating Committee (GNC)	Investment Funds Oversight Committee (IFOC)[2]	Nuclear Operations (N.Ops)[2]	Major Projects Committee (MPC)[2]	Nuclear Generation Projects Committee (NGPC)
George Lewis, Chair	**Bill Sheffield, Chair**	**Corbin McNeill, Chair**	**Peggy Mulligan, Chair**	**Don Hintz, Chair**	**David MacMillan, Chair**	**Corbin McNeill, Chair**
Gary Kugler	Jake Epp	Jake Epp	George Lewis	Gary Kugler	Ian Ross	Jake Epp
Peggy Mulligan	Don Hintz	Gary Kugler	Corbin McNeill	David MacMillan	Marie Rounding	Don Hintz
Ian Ross	David Unruh	Ian Ross	Marie Rounding	Corbin McNeill	Bill Sheffield	Gary Kugler
David Unruh			Bill Sheffield	Marie Rounding	David Unruh	Ian Ross

1 Board commitee memberships are current as of May 2007.
2 The Board Chair will attend meetings.

Officers



Jake Epp

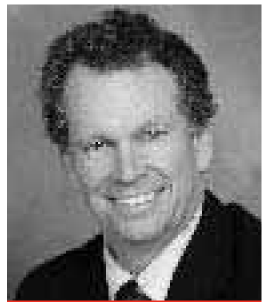
Chairman

Jim Hankinson

President and CEO

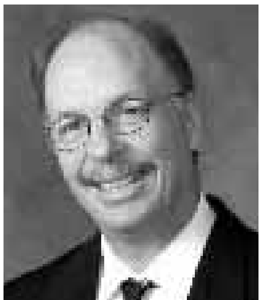
Bruce Boland

Senior Vice President,
Corporate Affairs



David Brennan

Senior Vice President,
Law and General Counsel



Jim Burpee

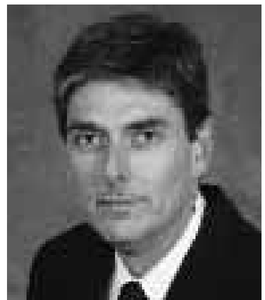
Executive Vice President,
Corporate Development

Pierre Charlebois

Executive Vice President
and Chief Operating Officer

Janice Dunlop

Senior Vice President,
Human Resources and
Chief Ethics Officer



Donn Hanbidge

Senior Vice President and
Chief Financial Officer

Catriona King

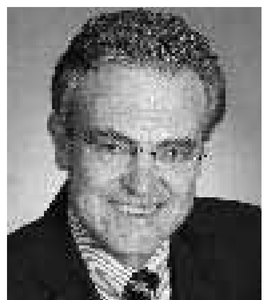
Vice President,
Corporate Secretary

Tom Mitchell

Chief Nuclear Officer

John Murphy

Executive Vice President,
Hydro

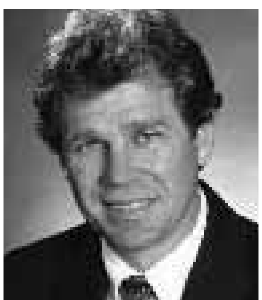


Ken Nash

Senior Vice President,
Nuclear Waste Management

Colleen Sidford

Vice President, Treasurer



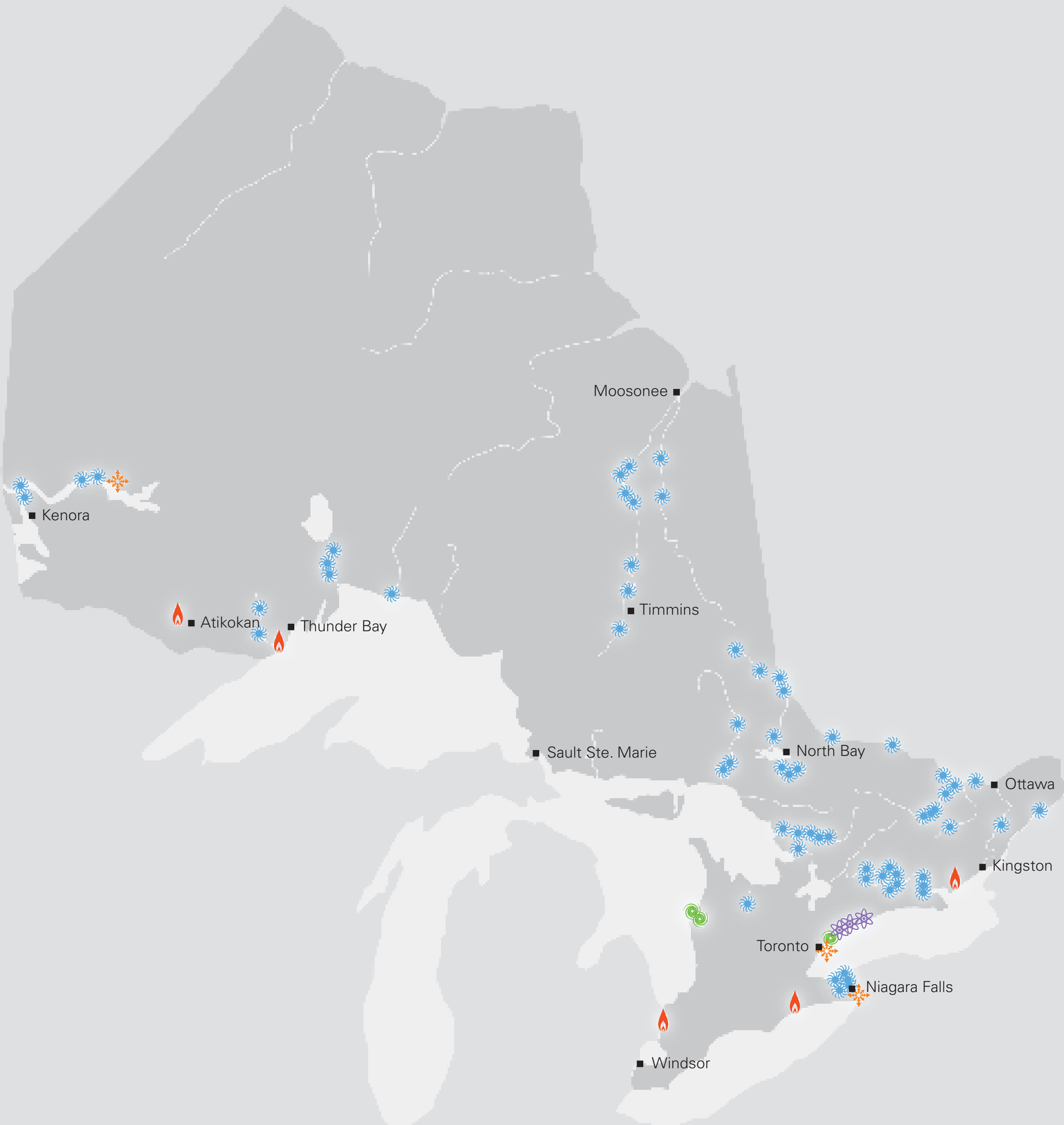
Gregory Smith

Senior Vice President,
Nuclear Generation
Development and Services

Jim Twomey

Executive Vice President,
Fossil

Ontario Power Generation Facilities



3	5	64	3	3
Nuclear Stations	**Fossil-Fuelled Stations**	**Hydroelectric Stations**	**Wind Power Stations***	**New Generation Projects**

*Includes a 50% interest in the Huron Wind joint venture

This annual report is also available in French on our Web site – ce rapport est également publié en français – at **www.opg.com**

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telephone (416) 592-2555 or (877) 592-2555.

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Pictured on the Front Cover

Darlington planned outage, Spring 2006; Co-Op Student, Lambton Generating Station; Authorized Nuclear Operators, Pickering B; Employee, OPG's Western Waste Management Facility; OPG employees, Cameron Falls hydroelectric generating station

ONTARIO POWER GENERATION

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February 29, 2008

ONTARIO POWER GENERATION REPORTS 2007 FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the year ended December 31, 2007. Net income for the year was $528 million compared to net income of $490 million for the year ended December 31, 2006.

"In 2007, safety performance was the best since the Company's inception in 1999, and the performance of our generating stations improved significantly. Ensuring employee and public safety, and improving the performance of our existing assets are two important priorities. The reliability of our generating stations improved over the previous year with the exception of the Pickering A and B nuclear stations, where one-time events unfavourably affected production in 2007," said President and CEO Jim Hankinson.

Electricity generated in 2007 of 105.1 terawatt hours ("TWh") was essentially equal to production of 105.2 TWh in 2006. Electricity production from OPG's nuclear stations of 44.2 TWh in 2007 decreased from 2006 production of 46.9 TWh. Production at the Pickering A station decreased primarily as a result of a requirement to perform modifications to a backup electrical system, and repair work required due to a component failure during inspection. In addition, production at the Pickering B station during the first quarter of 2007 was affected by an inadvertent release of resin by a third party contractor from the water treatment plant into the demineralized water system. Hydroelectric production of 31.9 TWh was slightly lower than production of 33.3 TWh in 2006 due to lower water levels. Fossil production increased to 29.0 TWh in 2007 compared to 25.0 TWh in 2006, mainly as a result of lower generation from OPG's nuclear and hydroelectric generating stations.

OPG received an average price of 4.6¢/kilowatt hour ("kWh") for the output from all of its generating stations in 2007. This average price equalled that of 2006. These average prices received by OPG reflect regulated prices for production from its nuclear and baseload hydroelectric generating assets, and spot market prices, subject to a revenue limit, for the majority of its remaining production. The average Ontario electricity spot market price in 2007 increased to 5.1¢/kWh from 4.9¢/kWh in 2006.

Earnings in 2007 were favourably affected by an increase in earnings from the Nuclear Funds, an increase in non-electricity generation revenue, higher fossil generation, a decrease in income tax expense largely due to an additional contribution to the Nuclear Funds that is deductible for tax purposes, and lower depreciation expense primarily due to the extension in 2006 of the service lives of the coal-fired generating stations for accounting purposes. These favourable impacts were partly offset by lower generation from OPG's Pickering nuclear stations, and higher nuclear and fossil maintenance expenses.

OPG continues to pursue a number of hydroelectric generation projects, and, in consultation with its shareholder, plans to explore and develop, where feasible, nuclear and natural gas generation projects. The following projects will significantly contribute to meeting Ontario's long-term electricity supply requirements.

- Excavation of a new 10.4 km water diversion tunnel to increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara began in September 2006. At December 31, 2007, the tunnel boring machine had advanced 1,609 metres. The progress of the tunnel boring machine through a fractured rock formation has been slower than expected. Considerable uncertainty remains with respect to the schedule until the tunnel boring machine advances to approximately 2,300 metres, and establishes consistent tunneling performance. The contractor has advised that the in-service date of the tunnel will be delayed, and is investigating alternatives, including the realignment of the tunnel, to mitigate the impact of the delay. The estimated in-service date will be dependent on the alternative selected by the contractor. There is a potential risk that the schedule delay could impact the project cost.

- Construction of the new 12.5 megawatt ("MW") Lac Seul hydroelectric generating station on the English River began during the first quarter of 2006. The design-build contractor indicated that the project is expected to be in-service in the third quarter of 2008. There have been project delays due to various difficulties, including the replacement of the major subcontractor on two occasions.

- OPG plans to redevelop four existing hydroelectric stations that are nearing the end of their useful lives. Three stations are on the Upper Mattagami River and one is located on the Montreal River. The total installed capacity of the four stations will increase from 23 MW to 44 MW. Project completion is planned for the second quarter of 2011.

- OPG is expanding the Healey Falls generating station by 6.4 MW on the Trent-Severn Waterway. Project completion is planned for mid-2010.

- OPG plans to increase the generating capacity of four hydroelectric generating stations on the Lower Mattagami River. The incremental capacity associated with these stations totals 450 MW. Following discussions with the Canadian Environmental Assessment Agency ("CEAA"), a scoping document for a comprehensive study process has been posted on the CEAA website for public comment. OPG is engaged in consultations with First Nation stakeholders regarding an agreement to address past issues and establish a new commercial relationship.

- The Portlands Energy Centre ("PEC") is a 550 MW gas-fired, combined cycle generating station that is under construction near downtown Toronto. PEC is a limited partnership between OPG and TransCanada Energy Ltd. Construction of the station started in 2006 and is expected to be operational in a simple cycle mode, with a capacity of up to 340 MW, by June 1, 2008. The generating station is expected to be completed in a combined cycle mode in the second quarter of 2009, providing up to 550 MW of power.

- OPG is exploring the potential development of a gas-fuelled electricity generating station at its Lakeview site. Construction of a new plant would proceed only after required approvals and a clean energy supply agreement are obtained.

- OPG is proceeding with a feasibility study on the refurbishment and life extension of the Pickering B nuclear generating station. This work includes an assessment of the plant condition, an Environmental Assessment ("EA"), and an Integrated Safety Review. The requirements of the EA and the Integrated Safety Review have extended the timeframe required to define the scope of the refurbishment project and complete a comprehensive assessment. As a result, OPG plans to make a recommendation on this project to its Board of Directors in early 2009. OPG plans to begin a feasibility study on the refurbishment of the Darlington nuclear generating station in 2008.

- In September 2006, OPG initiated a federal approvals process for new nuclear generating units at the Darlington nuclear generating site. An Application for a Site Preparation licence was filed with the Canadian Nuclear Safety Commission ("CNSC"). In 2007, OPG implemented initiatives in support of an EA for new nuclear units at the Darlington site and filed a project description with the CNSC to determine the type of EA required. In January 2008, the CNSC recommended to the Federal government that the project proceed directly to a panel review, which is the highest level of review under current legislation. The panel review decision is pending.

Ontario's Minister of Energy has directed the Ontario Power Authority ("OPA") to negotiate Hydroelectric Energy Supply Agreement's with OPG for the following hydroelectric development projects: Lac Seul, Upper Mattagami , Hound Chute, Healey Falls, and Lower Mattagami. The directive indicated that the negotiation and execution of these agreements should be completed in the first half of 2008.

"The list of new generation projects that OPG is undertaking is unprecedented. In consultation with our Shareholder, we will develop these much-needed new sources of electricity supply to help meet Ontario's future electricity needs. Our objective is to efficiently manage and complete these small, medium, and large scale projects in a timely and cost effective manner," said Hankinson.

Hankinson added, "In 2008, the OEB will review OPG's application for new payment amounts for our regulated facilities. We look forward to presenting our case for receiving a fair return on equity for our regulated assets as a transition to a financially sustainable company."

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2007**	**2006**
Earnings		
Revenue after revenue limit rebate	**5,660**	5,564
Fuel expense	**1,270**	1,098
Gross margin	**4,390**	4,466
Operations, maintenance and administration	**2,974**	2,752
Other expenses	**939**	1,138
Income tax (recoveries) expenses	**(51)**	86
Net income	**528**	490
Cash flow		
Cash flow provided by operating activities	**407**	397
Electricity Generation (TWh)		
Regulated – Nuclear	**44.2**	46.9
Regulated – Hydroelectric	**18.1**	18.3
Unregulated – Hydroelectric	**13.8**	15.0
Unregulated – Fossil-Fuelled	**29.0**	25.0
Total electricity generation	**105.1**	105.2
Average electricity sales price [1] (¢/kWh)		
Regulated – Nuclear [1]	**4.9**	4.9
Regulated – Hydroelectric [1]	**3.5**	3.5
Unregulated – Hydroelectric [2]	**4.7**	4.6
Unregulated – Fossil-Fuelled [2]	**4.8**	4.8
OPG's average sales price	**4.6**	4.6
Nuclear unit capability factor (per cent)		
Darlington	**89.5**	88.7
Pickering A	**41.3**	72.0
Pickering B	**75.0**	75.2
Equivalent forced outage rate (per cent)		
Unregulated– Fossil-Fuelled	**11.5**	14.1
Availability (per cent)		
Regulated – Hydroelectric	**94.1**	94.2
Unregulated – Hydroelectric	**93.9**	92.4

1 After April 1, 2005, electricity generation from stations in the Regulated – Nuclear segment receives a fixed price of 4.95¢/kWh and electricity generation from stations in the Regulated – Hydroelectric segment receives a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

2 Eighty-five per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, is subject to a revenue limit. During the period from April 1, 2005 to April 30, 2006, the revenue limit was set at 4.7¢/kWh. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh and increased to 4.7¢/kWh effective May 1, 2007.

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2007, can be accessed on OPG's Web site (www.opg.com), the Canadian Securities Administrators' Web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
1-866-592-6700
investor.relations@opg.com

Media Relations 416-592-4008
1-877-592-4008

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STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s ("OPG") management is responsible for presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and the requirements of the Ontario Securities Commission ("OSC"), as applicable. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal controls and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and sound and conservative accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of OPG's disclosure controls and procedures (as defined in Multilateral Instrument 52-109 of the Canadian Securities Administrators) as of December 31, 2007. Management concluded that, as of December 31, 2007, OPG's disclosure controls and procedures were effective to provide reasonable assurance that material information relating to OPG and its consolidated subsidiaries and interests in jointly controlled entities would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

Management has designed internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Accordingly, we, as OPG's Chief Executive Officer and Chief Financial Officer, will certify OPG's annual disclosure documents filed with the OSC, which includes attesting to the design and effectiveness of OPG's disclosure controls and procedures and the design of internal control over financial reporting.

The Board of Directors, based on recommendations from its Audit/Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jim Hankinson (signed)
President and Chief Executive Officer

Donn W. J. Hanbidge (signed)
Chief Financial Officer

February 27, 2008

AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the consolidated balance sheets of Ontario Power Generation Inc. as at December 31, 2007 and 2006 and the consolidated statements of income, changes in shareholder's equity, comprehensive income and cash flows for the years then ended. These consolidated financial statements are the responsibility of Ontario Power Generation Inc.'s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

ERNST & YOUNG LLP (signed)
Chartered Accountants, Licensed Public Accountants
Toronto, Canada
February 27, 2008

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2007**	**2006**
Revenue *(Note 19)*		
Revenue before revenue limit rebate	**5,887**	5,725
Revenue limit rebate *(Note 16)*	**(227)**	(161)
	5,660	5,564
Fuel expense	**1,270**	1,098
Gross margin	**4,390**	4,466
Expenses *(Note 19)*		
Operations, maintenance and administration	**2,974**	2,752
Depreciation and amortization *(Note 5)*	**695**	689
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 10)*	**507**	499
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**(481)**	(371)
Property and capital taxes	**85**	106
	610	791
Income before the following:		
Other (gains) and losses *(Note 17)*	**(10)**	22
Income before interest and income taxes	**620**	769
Net interest expense	**143**	193
Income before income taxes	**477**	576
Income tax (recovery) expense *(Note 11)*		
Current	**1**	60
Future	**(52)**	26
	(51)	86
Net income	**528**	490
Basic and diluted income per common share *(dollars)*	**2.06**	1.91
Common shares outstanding *(millions)*	**256.3**	256.3

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	**2007**	**2006**
Operating activities		
Net income	**528**	490
Adjust for non-cash items:		
Depreciation and amortization *(Note 5)*	**695**	689
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 10)*	**507**	499
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**(481)**	(371)
Pension cost *(Note 12)*	**243**	218
Other post employment benefits and supplementary pension plans *(Note 12)*	**244**	255
Future income taxes *(Note 11)*	**(52)**	26
Transition rate option contracts	**-**	(12)
Mark-to-market on derivative instruments	**1**	(29)
Provision for used nuclear fuel	**30**	33
Regulatory assets and liabilities *(Note 7)*	**(11)**	2
Other (gains) and losses *(Note 17)*	**(10)**	22
Provision for other liabilities	**54**	22
Other	**25**	(11)
	1,773	1,833
Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**(788)**	(454)
Expenditures on fixed asset removal and nuclear waste management *(Note 10)*	**(200)**	(164)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management *(Note 10)*	**119**	19
Contributions to pension fund *(Note 12)*	**(268)**	(261)
Expenditures on other post employment benefits and supplementary pension plans *(Note 12)*	**(73)**	(69)
Revenue limit rebate *(Note 16)*	**(167)**	(860)
Expenditures on restructuring	**(2)**	(8)
Net changes to other long-term assets and liabilities	**(56)**	(116)
Changes in non-cash working capital balances *(Note 23)*	**69**	477
Cash flow provided by operating activities	**407**	397
Investing activities		
Increase in regulatory assets *(Note 7)*	**(58)**	(13)
Investment in fixed assets *(Notes 5 and 18)*	**(666)**	(637)
Cash and cash equivalents transferred to long-term investments *(Note 6)*	**(58)**	-
Cash flow used in investing activities	**(782)**	(650)
Financing activities		
Issuance of long-term debt *(Note 9)*	**900**	270
Repayment of long-term debt *(Note 9)*	**(406)**	(806)
Dividend paid	**-**	(128)
Net (decrease) increase in short-term notes *(Note 8)*	**(15)**	15
Cash flow provided by (used in) financing activities	**479**	(649)
Net increase (decrease) in cash and cash equivalents	**104**	(902)
Cash and cash equivalents, beginning of year	**6**	908
Cash and cash equivalents, end of year	**110**	6

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	**2007**	**2006**
Assets		
Current assets		
Cash and cash equivalents	**110**	6
Accounts receivable *(Notes 4 and 19)*	**315**	230
Fuel inventory *(Note 18)*	**604**	669
Prepaid expenses	**35**	26
Future income taxes *(Note 11)*	**12**	-
Materials and supplies *(Note 18)*	**125**	112
	1,201	1,043
Fixed assets *(Notes 5 and 18)*		
Property, plant and equipment	**17,772**	17,136
Less: accumulated depreciation	**4,995**	4,375
	12,777	12,761
Other long-term assets		
Deferred pension asset *(Note 12)*	**731**	706
Nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**9,263**	7,594
Long-term investments *(Notes 6 and 21)*	**93**	32
Long-term materials and supplies *(Note 18)*	**353**	326
Regulatory assets *(Note 7)*	**356**	251
Long-term accounts receivable and other assets	**65**	37
	10,861	8,946
	24,839	22,750

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	**2007**	**2006**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Notes 12 and 19)*	**953**	989
Revenue limit rebate payable *(Note 16)*	**100**	40
Short-term notes payable *(Note 8)*	**-**	15
Long-term debt due within one year *(Note 9)*	**407**	406
Future income taxes *(Note 11)*	**-**	3
Deferred revenue due within one year	**12**	12
Income and capital taxes payable *(Note 11)*	**66**	128
	1,538	1,593
Long-term debt *(Note 9)*	**3,446**	2,953
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(Note 10)*	**10,957**	10,520
Other post employment benefits and supplementary pension plans *(Note 12)*	**1,556**	1,396
Long-term accounts payable and accrued charges	**184**	150
Deferred revenue	**120**	132
Future income taxes *(Note 11)*	**217**	246
Regulatory liabilities *(Note 7)*	**14**	11
	13,048	12,455
Shareholder's equity		
Common shares *(Note 14)*	**5,126**	5,126
Retained earnings	**1,664**	623
Accumulated other comprehensive income	**17**	-
	6,807	5,749
	24,839	22,750

Commitments and Contingencies (Notes 2, 8, 9, 10, 11, 13, 15, and 18)

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

Honourable Jake Epp (signed)
Chairman

M. George Lewis (signed)
Director

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2007**	**2006**
Common shares *(Note 14)*	**5,126**	5,126
Retained earnings		
Balance at beginning of year	**623**	261
Transition adjustment on adoption of financial instruments accounting standards *(Note 3)*	**513**	-
Net income	**528**	490
Dividends	**-**	(128)
Balance at end of year	**1,664**	623
Accumulated other comprehensive income, net of income taxes		
Balance at beginning of year	**-**	
Transition adjustment on adoption of financial instruments accounting standards *(Note 3)*	**21**	
Other comprehensive income for the year	**(4)**	
Balance at end of year	**17**	
Total shareholder's equity at end of year	**6,807**	

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year Ended December 31, 2007 *(millions of dollars)*	
Net income	**528**
Other comprehensive loss, net of income tax	
Net gain on derivatives designated as cash flow hedges[1]	**11**
Reclassification to income of gains on derivatives designated as cash flow hedges[2]	**(15)**
Other comprehensive loss for the year	**(4)**
Comprehensive income	**524**

[1] Net of income tax of $1 million for the year ended December 31, 2007.

[2] Net of income tax benefit of $9 million for the year ended December 31, 2007.

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2007 AND 2006

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. ("OPG" or the "Company") was incorporated on December 1, 1998 pursuant to *the Business Corporations Act* (Ontario). As part of the reorganization of Ontario Hydro, under the *Electricity Act, 1998* and the related restructuring of the electricity industry in Ontario, Ontario Power Generation Inc. and its subsidiaries (collectively "OPG" or the "Company") purchased and assumed certain assets, liabilities, employees, rights and obligations of the electricity generation business of Ontario Hydro on April 1, 1999 and commenced operations on that date. Ontario Hydro has continued as Ontario Electricity Financial Corporation ("OEFC"), responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations.

2. BASIS OF PRESENTATION

These consolidated financial statements were prepared in accordance with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

The consolidated financial statements include the accounts of OPG and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant intercompany transactions have been eliminated on consolidation.

Certain of the 2006 comparative amounts have been reclassified from financial statements previously presented to conform to the 2007 financial statement presentation.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost or market.

Interest earned on cash and cash equivalents and short-term investments of $5 million (2006 – $21 million) at an average effective rate of 4.4 per cent (2006 – 4.0 per cent) is offset against interest expense in the consolidated statements of income.

Sales of Accounts Receivable

Asset securitization involves selling assets such as accounts receivable to independent entities or trusts, which buy the receivables and then issue interests in them to investors. These transactions are accounted for as sales, given that control has been surrendered over these assets in return for net cash consideration. For each transfer, the excess of the carrying value of the receivables transferred over the estimated fair value of the proceeds received is reflected as a loss on the date of the transfer, and is included in net interest expense. The carrying value of the interests transferred is allocated to accounts receivable sold or interests retained according to their relative fair values on the day the transfer is made.

Fair value is determined based on the present value of future cash flows. Cash flows are projected using OPG's best estimates of key assumptions, such as discount rates, weighted average life of accounts receivable and credit loss ratios.

As part of the sales of accounts receivable, certain financial assets are retained and consist of interests in the receivables transferred. Any retained interests held in the receivables are accounted for at cost. The receivables are transferred on a fully serviced basis and do not create a servicing asset or liability.

Inventories

Fuel inventory is valued at weighted average cost.

Materials and supplies are valued at the lower of average cost and net realizable value. The determination of net realizable value of materials and supplies takes into account various factors including the remaining useful life of the related facilities in which the materials and supplies are expected to be used.

Fixed Assets and Depreciation

Property, plant and equipment are recorded at cost. Interest costs incurred during construction are capitalized as part of the cost of the asset based on the interest rate on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are also charged to depreciation expense. Repairs and maintenance are expensed when incurred.

Fixed assets are depreciated on a straight-line basis except for computers, and transport and work equipment, which are depreciated on a declining balance basis as noted below:

Nuclear generating stations and major components	15 to 49 years [1]
Fossil generating stations and major components	25 to 40 years [2]
Hydroelectric generating stations and major components	25 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] The end of station life for depreciation purposes for the Darlington, Pickering A, Pickering B, and Bruce B nuclear generating stations ranges between 2012 and 2021. Major components are depreciated over the lesser of the station life and the life of the components. The Bruce A nuclear generating station was fully depreciated in 2003. Bruce Power decided to refurbish the Bruce A generating station contributing to an increase in the asset retirement obligation at December 31, 2006 and an increase in the carrying value of the Bruce A station. For the year ended December 31, 2007, the depreciation of the Bruce A station was calculated based on the end-of-life date of 2030.

[2] Commencing July 1, 2006, the end of station life for depreciation purposes for the coal-fired generating stations was changed to 2012, due to the expected shutdown of these stations by the end of 2012.

[3] The end of station life for depreciation purposes disclosed above excludes the impact of life extensions commencing January 1, 2008, which are described under the heading, *Changes in Accounting Policies and Estimates*.

Impairment of Fixed Assets

OPG evaluates its property, plant and equipment for impairment whenever conditions indicate that estimated undiscounted future net cash flows may be less than the net carrying amount of assets. In cases where the undiscounted expected future cash flows are less than the carrying amount, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available.

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* (Ontario) received Royal Assent. A regulation made pursuant to that statute by the Province of Ontario (the "Province") in February 2005 provides that OPG receives regulated prices beginning April 1, 2005 for electricity generated from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that it operates. This includes electricity generated from Sir Adam Beck 1, 2 and Pump generating stations, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear facilities. The regulation was amended in February 2007. The amendment clarified certain aspects of the regulation and directed OPG to establish a deferral account related to certain changes in its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management.

The amendment issued in February 2007 also clarified that the OEB must ensure that OPG recovers, through future regulated prices, all capital and non-capital costs incurred in order to increase the output of, refurbish or add operating capacity to a regulated facility. The amendment requires these costs be within budgets approved by OPG's Board of Directors prior to the OEB's first order establishing regulated prices or that the OEB is satisfied that these costs were prudently incurred.

In February 2008, a second amendment to the regulation was made by the Province. This amendment directs OPG to establish a deferral account to record, for the period up to the effective date of the OEB's first order, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities. This amendment further directs OPG to establish a variance account to record, for the period on or after the effective date of the OEB's first order, the differences between actual non-capital costs incurred and firm financial commitments made, and the amounts included in the approved regulated price related to planning and preparation for the development of proposed new nuclear generation facilities. In addition, the amendment states that the OEB must ensure that OPG recovers these costs to the extent the OEB is satisfied that the costs were prudently incurred or commitments prudently made.

OPG's regulated prices were established by the Province based on a forecast of production volumes and total operating costs, and a return on rate base, which assumed an average five per cent rate of return on equity. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets and an allowance for working capital. The initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time the Ontario Energy Board (the "OEB") will assume responsibility for establishing new regulated prices.

The OEB is a self-funding crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, *the Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates all market participants in the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the consolidated financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred expenses will be recovered in the future, then OPG may defer those expenses and report them as a regulatory asset. If current recovery is provided for expenses expected to be incurred in the future, then OPG reports a regulatory liability. Also, if the regulation provides for lesser or greater than planned revenue to be received or returned by OPG through future regulated prices, then OPG recognizes a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation. See Notes 7 and 11 to the audited consolidated financial statements for additional disclosure related to rate regulated accounting.

Investments in OPG Ventures

In accordance with Accounting Guideline 18, *Investment Companies* ("AcG-18"), investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV") are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated based on readily available market information or using estimation techniques based on historical performance.

Fixed Asset Removal and Nuclear Waste Management Liability

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liability is increased by the present value of the variable cost portion of the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Expenses relating to low and intermediate level waste are charged to depreciation and amortization expense. Expenses relating to the disposal or storage of nuclear used fuel are charged to fuel expense. The liability may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liability, a gain or loss would be recorded.

Accretion arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time. The resulting expense is included in operating expenses.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining useful life of the related fixed assets and is included in depreciation expense.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province of Ontario, OPG established a Used Fuel Segregated Fund ("Used Fuel Fund") and a Decommissioning Segregated Fund ("Decommissioning Fund") (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund expenditures associated with the disposal of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

The Nuclear Funds are invested in fixed income and equity securities. Prior to 2007, OPG recorded the investments in the Nuclear Funds as long-term investments and accounted for the investments at their amortized cost value. Therefore, gains and losses were recognized only upon the sale of an underlying security. As such, there may have been unrealized gains and losses associated with the investments in the Nuclear Funds, which OPG had not recognized in its consolidated financial statements.

Effective January 1, 2007, OPG adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, Financial Instruments – Recognition and Measurement. As a result of the adoption of this new section, the investments in the Nuclear Funds and the corresponding payables to the Province are classified as held-for-trading. Accordingly, the Nuclear Funds and the corresponding payables to the Province are measured at fair value based on the bid prices of the underlying securities with gains and losses recognized in net income. More details on the impact of the new accounting standards are provided in the Accounting Changes section.

Revenue Recognition

All of OPG's electricity generation is sold into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO"). Prior to April 1, 2005, revenue was recorded as electricity was generated and metered based on the spot market sales price, net of the Market Power Mitigation Agreement rebate and hedging activities. At each balance sheet date, OPG computed the average spot energy price that prevailed since the beginning of the current settlement period and recognized a Market Power Mitigation Agreement rebate if the average price exceeded 3.8¢/kilowatt hour ("kWh"), based on the amount of energy subject to the rebate.

Effective April 1, 2005, the generation from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates became rate regulated. As a result, energy revenue generated from the nuclear facilities is recognized based on a regulated price of 4.95¢/kWh. The regulated price received by OPG for the first 1,900 megawatt hours ("MWh") of production from the regulated hydroelectric facilities in any hour is 3.3¢/kWh. Any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price.

The production from OPG's remaining hydroelectric, fossil-fuelled and wind generating stations remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from these other generating assets, excluding the Lennox generating station, stations whose generation output is subject to a Hydroelectric Energy Supply Agreement ("HESA") with the Ontario Power Authority ("OPA") pursuant to a ministerial directive, and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets are also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate. This revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and will increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the OPA are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these two revenue limits are returned to the IESO for the benefit of consumers.

OPG also sells into, and purchases from, interconnected markets of other provinces and the U.S. northeast and midwest. All contracts that are not designated as hedges are recorded in the consolidated balance sheets at market value with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $120 million in 2007 and $163 million in 2006 were netted against revenue.

OPG derives non-energy revenue under the terms of a lease arrangement with Bruce Power L.P. ("Bruce Power") related to the Bruce nuclear generating stations. This includes lease revenues and revenues for engineering analysis and design, technical and ancillary services. OPG also earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, non-energy revenue includes isotope sales and real estate rentals. Revenues from these activities are recognized as services are provided or as products are delivered.

Derivatives

OPG is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the wholesale price of electricity, OPG enters into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized in unregulated revenue over the term of the contract when the underlying hedged transactions occur. All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in other revenue.

OPG also enters into derivative contracts with major financial institutions to manage the Company's exposure to foreign currency movements. Foreign exchange translation gains and losses on these foreign currency denominated derivative contracts are recognized as an adjustment to the purchase price of the commodity or goods received.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded through net income in the period incurred.

OPG utilizes emission reduction credits ("ERCs") and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances are held in inventory and charged to OPG's operations at average cost as part of fuel expense as required. Options to purchase ERCs are accounted for as derivatives and are recorded at estimated market value.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. The fair value of such derivative instrument is included in accumulated other comprehensive income (“AOCI”) on a net of tax basis and changes to the fair value are recorded on the consolidated statement of comprehensive income. When a derivative hedging relationship is expired, the designation of a hedging relationship is terminated, or a portion of the hedging instrument is no longer effective, any associated gains or losses included in AOCI are recognized in the current period’s consolidated statement of income.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at year-end exchange rates. Any resulting gain or loss is reflected in revenue.

Research and Development

Research and development costs are charged to operations in the year incurred. Research and development costs incurred to discharge long-term obligations such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Pension and Other Post Employment Benefits

OPG’s post employment benefit programs include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, group life insurance, health care and long-term disability benefits. OPG accrues its obligations under pension and other post employment benefit ("OPEB") plans. The obligations for pension and other post retirement benefit costs are determined using the projected benefit method pro-rated on service. The obligation for long-term disability benefits is determined using the projected benefit method on a terminal basis. The obligations are affected by salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management’s best estimate assumptions. The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields.

Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPEB plan amendments are amortized on a straight-line basis over the expected average remaining service life of the employees covered by the plan, since OPG will realize the economic benefit over that period. Due to the long-term nature of post-employment liabilities, the excess of the net cumulative unamortized gain or loss, over 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets, is also amortized over the expected average remaining service life.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Taxes

Under the *Electricity Act, 1998*, OPG is responsible for making payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes of its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered or refunded in future regulated prices charged to customers.

OPG makes payments in lieu of property tax on its nuclear and fossil-fuelled generating assets to the OEFC, and also pays property taxes to municipalities.

OPG pays charges on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense.

Changes in Accounting Policies and Estimates

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Effective January 1, 2006, following the completion of a review of the life limiting components of the Pickering B nuclear generating station, OPG revised and extended, for the purpose of calculating depreciation, the estimated remaining service life of the Pickering B nuclear generating station to 2014 from 2009. The extension reduced depreciation expense by $36 million in 2006 and in 2007.

The Province accepted the advice of the IESO in their June 2006 report that indicated a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays were necessary in the Province's plan to replace coal-fired generation by 2009. As a result of delays in the plan to replace coal-fired generation by 2009, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension reduced depreciation expense by $64 million in 2006, $126 million in 2007, and $46 million in 2008. From 2009 to 2012, the depreciation expense will increase by $59 million in each year. OPG will reassess the service life of the coal-fired generating stations upon release of the submitted Integrated Power System Plan, and as subsequently approved by the OEB. Any change to the estimated service life of the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

Effective January 1, 2008, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended by two years to 2019 after a review of the technical analysis for life limiting components. The life extension will reduce depreciation expense by $18 million annually.

The Company has extended the service life of Bruce B nuclear generating station to 2014 for depreciation purposes effective January 1, 2008 after reviewing future capacity plans in the OPA's Integrated Power System Plan, which was filed with the OEB in August 2007, and historical information regarding the service lives of major life limiting components of the station. As a result of the extension, depreciation expense will be reduced by $7 million annually. In addition, effective January 1, 2008, OPG extended the service life of Bruce A nuclear generating station to 2035 for depreciation purposes after the review of future capacity plans filed with the OPA and other publicly available information. The extension of the service life to the Bruce A nuclear generating station for depreciation purposes will decrease depreciation expense by $8 million annually.

Financial Instruments

On January 1, 2007, OPG adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1530, *Comprehensive Income*; Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; and Handbook Section 3865, *Hedges*. Comparative amounts for prior periods have not been restated.

Comprehensive Income

As a result of adopting these standards, a new category, accumulated other comprehensive income, was added to shareholder's equity in the consolidated balance sheets. Comprehensive income consists of net income and other comprehensive income. This category includes changes in the fair value of the effective portion of cash flow hedging instruments. Amounts are recorded in other comprehensive income until the criteria for recognition in the consolidated statements of income are met.

Financial Instruments – Recognition and Measurement

Under the new standard, for accounting purposes, financial assets are classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities are classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading are measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables, and financial liabilities other than those held-for-trading, are measured at amortized cost. Financial assets available-for-sale are measured at fair value with unrealized gains and losses due to fluctuations in fair value recognized in accumulated other comprehensive income. Financial assets purchased and sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a trade-date basis. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

The new standard permits designation of any financial instrument as held-for-trading (the fair value option) upon initial recognition. This designation by OPG requires that the financial instrument be reliably measurable, and eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities.

Hedges

The new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item.

Impact of Adoption

Upon adoption of the financial instruments accounting standards, the assets in the Nuclear Funds that were carried at amortized cost until the end of 2006 were classified as held-for-trading and reported at fair value. The transition adjustment related to the change in accounting for the Nuclear Funds was recognized in the opening balance of retained earnings at January 1, 2007. The transition adjustment for embedded derivatives within long-term contracts was also recognized in the opening balance of retained earnings at January 1, 2007. OPG elected January 1, 2004 as the transition date for embedded derivatives. Prior to January 1, 2007, OPG disclosed the fair value of securities in the Nuclear Funds based on the closing price of the securities. Starting January 1, 2007, OPG applied bid pricing to determine the fair value of the securities.

The fair value of the Nuclear Funds based on bid pricing is lower than that reported in the 2006 comparative period. The change in pricing methodology does not have any impact to the overall balance on the consolidated balance sheets since the reduction in fair value is offset by the corresponding change in the due to Province balance.

The fair values of hedging instruments designated as cash flow hedges were recognized in the opening accumulated other comprehensive income on a net of tax basis. The fair values of these hedges are disclosed in Note 13 to the audited consolidated financial statements.

The transition amounts that were recorded in the opening retained earnings or in the opening accumulated other comprehensive income balance on January 1, 2007 were as follows:

	At Cost	**At Fair Value**	**Transition Amounts – January 1, 2007**	
(millions of dollars)	**December 31 2006**	**January 1 2007**	**Opening Retained Earnings**	**Opening Accumulated Other Comprehensive Income**
Nuclear Funds balance	7,694	9,041	1,347	-
Due to Province	(100)	(928)	(828)	-
	7,594	8,113	519	-
Accounts receivable and other assets	325	372	-	47
Accounts payable and accrued charges	(989)	(1,005)	(6)	(10)
Net future income tax liability	(249)	(265)	-	(16)
Transition adjustments			513	21

Future Changes in Accounting Policies

Capital Disclosures and Financial Instruments

In December 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures (“Section 1535”), Handbook Section 3862, Financial Instruments – Disclosures (“Section 3862”), and Handbook Section 3863, Financial Instruments – Presentation (“Section 3863”). These new standards are effective for the Company beginning January 1, 2008.

Section 1535 specifies the disclosure of (i) an entity’s objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance.

Sections 3862 and 3863 replace Handbook Section 3861, Financial Instruments – Disclosure and Presentation, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

Inventories

The CICA issued a new accounting standard, Section 3031, Inventories, in March 2007, which is based on International Accounting Standard ("IAS") 2. The new section replaced the existing Section 3030, Inventories. Under the new section, inventories are required to be measured at the "lower of cost and net realizable value", which is different from the existing guidance of "lower of cost and market". The new section also allows the reversal of any write-downs previously recognized. Further, due to the changes in the section and the consequential amendments, some of OPG's critical spare parts currently reported as materials and supplies on OPG's consolidated balance sheets will be accounted for as property, plant and equipment. The new accounting standard and the consequential amendments are effective for OPG beginning January 1, 2008. OPG reclassified significant critical spare parts of $19 million, net of accumulated depreciation, to property, plant and equipment in 2008.

Accounting for Regulatory Operations

In December 2007, the CICA revised its guidance on accounting for rate regulated operations. The revision resulted in amendments to Handbook Sections 1100, *Generally Accepted Accounting Principles*, and 3465, *Income Taxes*, and Accounting Guideline 19 ("AcG-19"), *Disclosures by Entities Subject to Rate Regulation,* as follows:

- to remove the temporary exemption pertaining to the application of Section 1100 to rate regulated operations, including the elimination of the opportunity to use industry practice as an acceptable basis for recognition and measurement of assets and liabilities arising from rate regulation;
- to amend Section 3465 to require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers; and
- to amend AcG-19, as necessary, as a result of amendments to Sections 1100 and 3465.

As a result of the changes to Section 3465, OPG will be required to recognize future income taxes associated with its rate regulated operations in the same manner as it currently recognizes future income taxes for its unregulated operations. OPG will apply the changes prospectively to interim and annual consolidated financial statements beginning January 1, 2009. OPG is currently evaluating the impact of implementing these changes on its consolidated financial statements.

4. SALE OF ACCOUNTS RECEIVABLE

In October 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables. In December 2005, the Company extended this agreement to August 2009.

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust, net of the undivided co-ownership interest retained by the Company. For 2007, OPG has recognized pre-tax charges of $15 million (2006 – $13 million) on such sales at an average cost of funds of 5.1 per cent (2006 – 4.4 per cent). As at December 31, 2007, OPG had sold receivables of $300 million from its total portfolio of $479 million (2006 – $392 million).

The accounts receivable reported and securitized by the Company are as follows:

(millions of dollars)	**Principal amount of receivables as at December 31**		**Average balance of receivables for the year ended December 31**	
	2007	**2006**	**2007**	**2006**
Total receivables portfolio [1]	**479**	392	**454**	445
Receivables sold	**300**	300	**300**	300
Receivables retained	**179**	92	**154**	145
Average cost of funds			**5.1%**	4.4%

[1] Amount represents receivables outstanding, including receivables that have been securitized, which the Company continues to service.

An immediate 10 per cent or 20 per cent adverse change in the discount rate would not have a material effect on the current fair value of the retained interest. There were no credit losses for the years ended December 31, 2007 and 2006.

Details of cash flows from securitizations for the years ended December 31, 2007 and 2006 are as follows:

(millions of dollars)	**2007**	**2006**
Collections reinvested in revolving sales [1]	**3,600**	3,600
Cash flows from retained interest	**1,759**	2,020

[1] Given the revolving nature of the securitization, the cash collections received on the receivables securitized are immediately reinvested in additional receivables resulting in no further cash proceeds to the Company over and above the initial cash amount of $300 million. The amounts reflect the total of 12 monthly amounts.

5. DEPRECIATION AND AMORTIZATION AND FIXED ASSETS

Depreciation and amortization expense consists of the following:

(millions of dollars)	**2007**	**2006**
Depreciation and amortization	**587**	659
Amortization of deferred Pickering A return to service costs *(Note 7)*	**96**	25
Nuclear waste management costs	**12**	5
	695	689

Fixed assets consist of the following:

(millions of dollars)	2007	2006
Property, plant and equipment		
Nuclear generating stations	**6,466**	6,275
Regulated hydroelectric generating stations	**4,411**	4,384
Unregulated hydroelectric generating stations	**3,525**	3,481
Fossil-fuelled generating stations	**1,553**	1,465
Other fixed assets	**867**	854
Construction in progress	**950**	677
	17,772	17,136
Less: accumulated depreciation		
Generating stations	**4,636**	4,066
Other fixed assets	**359**	309
	4,995	4,375
	12,777	12,761

Interest capitalized to construction in progress at six per cent during the years ended December 31, 2007 and 2006 was $42 million and $21 million, respectively.

Impairment of Long-Lived Assets

The accounting estimates related to asset impairment require significant management judgment to identify factors such as short and long-term forecasts for future sales prices, the supply of electricity in Ontario, inflation, fuel prices, and station lives. The amount of the future cash flow that OPG will ultimately realize with respect to these assets could differ materially from the carrying values recorded in the consolidated financial statements.

Thunder Bay and Atikokan Generating Stations

OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations in 2006 of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result of changes in circumstance, which included a decrease in forecast Ontario spot market prices and the extension of the lives of the coal-fired stations. The fair value of the coal-fired generating stations, which was determined using a discounted cash flow method, was compared to the carrying value of the generating assets to determine the impairment loss. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives.

6. INVESTMENTS IN ASSET-BACKED COMMERCIAL PAPER

In August 2007, a number of Canadian third-party Trusts, as issuers of asset-backed commercial paper (“ABCP”), experienced difficulty in accessing the liquidity required to repay maturing ABCP debt. OPG’s original exposure to third-party ABCP notes was $103 million. Of that total, $45 million consisted of notes held with Skeena Capital Trust (“Skeena”). In December 2007, OPG received payment of approximately $44 million against these notes and recognized an impairment loss of $1 million. The settlement amount represented 98.65 per cent of the original investment including interest up to the maturity date.

Following the settlement of investments in Skeena, OPG’s holdings of third-party ABCP was reduced to $58 million. On December 23, 2007, a restructuring plan was announced for the remaining third-party ABCP Trusts. Documentation of the restructuring plan for theses trusts is expected in March 2008.

Approval for any restructuring is required by note holders representing not less than 66 and two-thirds of the value of the Trusts.

OPG performed a valuation analysis as at December 31, 2007 to assess the amount of any impairment, taking into account the limited information available. The assessment considered the likelihood of achieving a successful restructuring based on the current proposal announced on December 23, 2007. OPG used a probability weighted cash flow model to determine the fair value of its third-party ABCP holdings. Since the majority of OPG's remaining ABCP is made up of combined traditional and synthetic assets such as Collateralized Debt Obligations ("CDO's"), the recoverability was estimated to be 85 per cent. An insignificant amount of OPG's remaining third-party ABCP is made up of ineligible assets, where the underlying assets or the collateral provided is supported by United States ("U.S.") sub-prime assets. The recoverability of these ineligible assets was estimated to be 70 per cent. OPG also considered alternative methods to assess the fair value of the investments. As a result of the analysis, OPG recorded an impairment loss of $9 million against the remaining holdings of $58 million, in addition to the $1 million loss related to the Skeena investments. The impairment loss is included in other gains and losses.

OPG reviewed the classification of its third-party ABCP holdings and has determined that a long-term classification is appropriate, based on the restructuring information available. OPG will continue to monitor developments with respect to ABCP and will continue to assess its position.

OPG has sufficient credit facilities to satisfy its financial obligations as they come due and does not expect any material adverse impact on its operations as a result of this current third-party ABCP liquidity issue.

7. REGULATORY ASSETS AND LIABILITIES AND SUMMARY OF RATE REGULATED ACCOUNTING

The regulatory assets and liabilities as at December 31, 2007 and 2006 are as follows:

(millions of dollars)	**2007**	**2006**
Regulatory assets		
Pickering A return to service costs	**183**	249
Nuclear liabilities deferral account	**131**	-
Nuclear generation development costs	**28**	-
Hydroelectric production variance	**7**	-
Ancillary service revenue variance	**5**	-
Transmission outages and transmission restrictions variance	**2**	2
Total regulatory assets	**356**	251
Regulatory liabilities		
Hydroelectric production variance	**-**	4
Other	**14**	7
Total regulatory liabilities	**14**	11

The changes in the regulatory assets and liabilities for 2007 and 2006 are as follows:

(millions of dollars)	**Pickering A Return to Service Costs**	**Nuclear Liabilities Deferral Account**	**Nuclear Generation Development Costs**	**Transmission Outages and Transmission Restrictions Variance**	**Hydro-electric Production Variance**	**Ancillary Services Revenue Variance**	**Other**
Regulatory assets (liabilities), January 1, 2006	261	-	-	-	(4)	5	(8)
Change during the year	13	-	-	2	-	(5)	1
Amortization during the year	(25)	-	-	-	-	-	-
Regulatory assets (liabilities), December 31, 2006	249	-	-	2	(4)	-	(7)
Change during the period	30	131	28	-	11	5	(7)
Amortization during the period	96	-	-	-	-	-	-
Regulatory assets (liabilities), December 31, 2007	**183**	**131**	**28**	**2**	**7**	**5**	**(14)**

Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004* (Ontario), OPG was required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that were associated with the planned return to service of all units at the Pickering A nuclear generating station. The regulation, as amended in February 2007, also requires OPG to record interest at an annual rate of six per cent on the balance in the deferral account. As at December 31, 2007, the balance in the deferral account was $183 million, consisting of non-capital costs of $232 million relating to Unit 1 and $19 million relating to Units 2 and 3, $20 million of general return to service non-capital costs and interest of $37 million, net of the accumulated amortization of $125 million. As at December 31, 2006, the balance in the deferral account was $249 million, consisting of non-capital costs of $232 million relating to Unit 1 and $19 million relating to Units 2 and 3, $20 million of general return to service non-capital costs and interest of $7 million, net of the accumulated amortization of $29 million.

There were no operations, maintenance and administration ("OM&A") costs charged to the deferral account during 2007. During 2006, OM&A expenses of $13 million were charged to the deferral account. Had OPG not charged these costs to the deferral account, OM&A expenses would have increased by $13 million for 2006.

During 2007, OPG deferred applied interest related to the Pickering A return to service deferral account of $30 million. Had OPG not applied interest to this account, the net interest expense would have increased by $30 million for 2007 (2006 – nil).

The costs accumulated in the deferral account are charged to operations in accordance with the terms of the regulation. Under the regulation, the OEB is directed to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years. Had OPG not amortized the costs in the deferral account, depreciation and amortization expense for 2007 would have been reduced by $96 million (2006 – $25 million).

Nuclear Liabilities Deferral Account

In February 2007, the Province amended a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to direct OPG to establish a deferral account in connection with certain changes to its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management. The deferral account represents the revenue requirement impact associated with the changes in the nuclear liabilities arising from an approved reference plan, approved after April 1, 2005, as reflected in OPG's audited consolidated financial statements. Revenue requirement is a regulatory construct, which represents all allowed costs and a return on rate base at a rate of return that the regulator determines to be appropriate. The regulation also requires OPG to record interest at an annual rate of six per cent on the balance in the deferral account.

On December 31, 2006, OPG recorded an increase in its nuclear liabilities of $1,386 million arising from an update to the approved reference plan in accordance with the terms of the Ontario Nuclear Funds Agreement ("2006 Approved Reference Plan"). Commencing January 1, 2007 and up to the effective date of OEB's first order establishing regulated prices, which is expected to be after March 31, 2008, OPG records a regulatory asset associated with the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan.

The OEB is directed by the regulation to ensure that OPG recovers the balance recorded in the deferral account on a straight-line basis over a period not to exceed three years, to the extent that the OEB is satisfied that the revenue requirement impacts are accurately recorded.

As at December 31, 2007, the following items have been recorded as components of the regulatory asset relating to the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan:

(millions of dollars)	**2007**
Return on rate base	**75**
Depreciation expense	**54**
Fuel expense	**(5)**
Capital tax	**3**
Interest expense	**4**
	131

The return on rate base component of $75 million was recorded as a reduction to the accretion expense on fixed asset removal and nuclear waste management expense for the year ended December 31, 2007.

For the year ended December 31, 2007, had OPG not established the deferral account as required by the regulation, accretion expense would have increased by $75 million, depreciation expense would have increased by $54 million, property and capital taxes expense would have been higher by $3 million, net interest expense would have increased by $4 million, and fuel expense would have been lower by $5 million.

The regulation also provides for the recovery of an amount relating to additional income taxes that OPG will be subject to as a result of recovering the regulatory asset through future regulated prices charged to customers. Since OPG has not yet incurred a related income tax expense, no amounts related to income taxes have been recorded as part of the regulatory asset.

Nuclear Generation Development Costs

The amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) made in February 2007 clarified that the OEB must ensure that OPG recovers, through future regulated prices, all capital and non-capital costs incurred in order to increase the output of, refurbish or add operating capacity to a regulated facility, if these costs are either within budgets approved by OPG's Board of Directors prior to the OEB's first order establishing regulated prices or if the OEB is satisfied that these costs were prudently incurred. A further amendment in February 2008, clarified that the OEB must ensure that OPG recovers the costs incurred and firm financial commitments made in the course of planning and preparing for the development of proposed new nuclear facilities. As a result of these amendments, OPG has recorded a regulatory asset of $28 million for the year ended December 31, 2007, which represents non-capital costs incurred for its nuclear generation development initiatives. Non-capital costs are recorded as a regulatory asset to the extent that they were incurred after April 1, 2005 and were not included in the forecast information provided to the Province for the purposes of establishing regulated prices.

Had OPG not recorded the above costs as a regulatory asset, OM&A expenses would have increased by $27 million and net interest expense would have increased by $1 million for the year ended December 31, 2007.

Variance Accounts and Other Regulatory Balances

Effective April 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004* (Ontario), OPG was directed to establish variance accounts for capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices. Variance accounts have been established for differences in hydroelectric electricity production due to differences between forecast and actual water conditions, unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear facilities, changes to revenues for ancillary services from the regulated facilities, acts of God (including severe weather events), and transmission outages and transmission restrictions.

OPG recorded an increase in revenue during the year ended December 31, 2007 of $5 million reflecting ancillary services revenue that was unfavourable compared to the forecast provided to the Province for the purposes of establishing regulated prices. In addition, OPG recorded an increase in revenue of $11 million in 2007 as a result of actual water conditions that were unfavourable to those forecast.

OPG recorded a decrease in revenue during the year ended December 31, 2006 of $5 million reflecting ancillary services revenue that was favourable compared to the forecast provided to the Province for the purposes of establishing regulated prices.

The OEB is directed by the regulation to ensure recovery of amounts recorded in the variance accounts to the extent that the OEB is satisfied that revenues recorded in the accounts were earned or foregone, that costs recorded in the accounts were prudently incurred, and that both revenues and costs are accurately recorded. Any balances approved by the OEB will be amortized over a period not to exceed three years. The amortization will commence when OPG starts to recover or return the balances through new prices that will be set by the OEB. Any balances in the accounts disallowed by the OEB will be reflected in the results of operations in the period that the OEB decision occurs.

The other regulatory liability consists of a portion of non-regulated revenue earned by OPG's regulated assets and interest on the account balance, which OPG expects to apply as a reduction to future regulated prices to be established by the OEB. OPG recorded an additional regulatory liability of $7 million in 2007 (2006 – an asset of $1 million), including $1 million of interest expense (2006 – nil).

Had OPG not accounted for the variance accounts and other regulatory balances as regulatory assets and liabilities, revenue for 2007 would have been lower by $12 million (2006 – higher by $2 million). Had OPG not accounted for the variance accounts and other regulatory balances as regulatory assets and liabilities, net interest expense for 2007 would have decreased by $1 million (2006 – nil).

Summary of Rate Regulated Accounting

The following tables summarize the impact of applying rate regulated accounting for selected income statement information:

Years Ended December 31	2007			2006		
(millions of dollars)	**As Stated**	**Impact of Rate Regulated Accounting**	**Financial Statements without Rate Regulated Accounting**	**As Stated**	**Impact of Rate Regulated Accounting**	**Financial Statements without Rate Regulated Accounting**
Revenue	**5,660**	**9**	**5,669**	5,564	30	5,594
Fuel expense	**1,270**	**(5)**	**1,265**	1,098	-	1,098
Operations, maintenance and administration	**2,974**	**27**	**3,001**	2,752	13	2,765
Depreciation and amortization	**695**	**(42)**	**653**	689	(25)	664
Accretion on fixed asset removal and nuclear waste management liabilities	**507**	**75**	**582**	499	-	499
Property and capital taxes	**85**	**3**	**88**	106	-	106
Net interest expense	**143**	**33**	**176**	193	-	193

Accounting for Certain Leases

OPG accounts for certain lease revenues relating to the regulated business using the cash basis of accounting. Under the cash basis of accounting, OPG recognizes lease income as stipulated in the lease agreement to the extent that the lease payments are expected to be included in future regulated prices charged to customers. If OPG did not apply the cash basis of accounting for leases, the revenue would have increased by $21 million (2006 – $21 million). As at December 31, 2007, had OPG accounted for the leases related to the regulated business using a straight-line basis, OPG would have reported a deferred lease receivable of $57 million (2006 – $36 million).

8. SHORT-TERM CREDIT FACILITIES

OPG's $1 billion revolving committed bank credit facility is divided into two tranches – a $500 million 364-day term tranche maturing May 21, 2008, and a $500 million five-year term tranche maturing May 22, 2012. The longer term tranche was extended from a three-year term to a five-year term, upon renewal of the bank credit facility in May 2007. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2007, there was no commercial paper outstanding (2006 – $15 million). OPG had no other outstanding borrowing under its bank credit facility as at December 31, 2007.

OPG also maintains $25 million (2006 – $26 million) in short-term uncommitted overdraft facilities as well as $238 million (2006 – $240 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other purposes. At December 31, 2007, there was a total of $205 million (2006 – $185 million) of Letters of Credit issued, which included $175 million (2006 – $159 million) relating to the supplementary pension plans and $16 million (2006 – $16 million) relating to the construction of the Portlands Energy Centre.

9. Long-Term Debt

Long-term debt consists of the following:

(millions of dollars)	2007	2006
Notes payable to the OEFC	**3,665**	3,165
Share of non-recourse limited partnership debt	**188**	194
	3,853	3,359
Less: due within one year		
Notes payable to the OEFC	**400**	400
Share of limited partnership debt	**7**	6
	407	406
Long-term debt	**3,446**	2,953

Holders of the senior debt are entitled to receive, in full, amounts owing in respect of the senior debt before holders of the subordinated debt are entitled to receive any payments. The OEFC currently holds all of OPG's outstanding senior and subordinated notes.

The maturity dates as at December 31, 2007 for notes payable to the OEFC are as follows:

		Principal Outstanding *(millions of dollars)*		
Year of Maturity	**Interest Rate (%)**	**Senior Notes**	**Subordinated Notes**	**Total**
2008	5.90%	400	-	400
2009	6.01%	350	-	350
2010	6.00%	595	375	970
2011	6.65%	-	375	375
2012	5.72%	400	-	400
2016	4.91%	270	-	270
2017	5.35%	900	-	900
		2,915	750	3,665

In September 2005, OPG reached an agreement with the OEFC to provide debt financing for the Niagara Tunnel project. The funding, which is up to $1 billion over the duration of the project, will be in the form of 10-year notes, which will be issued quarterly to meet the project's obligations. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. As at December 31, 2007, OPG issued $240 million against this facility, which included new borrowing of $80 million under the facility in 2007. In January 2008, $40 million of new borrowing was issued under the facility.

In December 2006, OPG reached an agreement with the OEFC to provide debt financing for the Lac Seul Hydroelectric Generating Station and the Portlands Energy Centre projects. There will be up to $50 million available for the Lac Seul project and up to $400 million available for the Portlands Energy Centre project under each credit facility. The credit facilities will be drawn as needed to fund the respective projects over the construction period. The funding will be in the form of 10-year notes with interest rates fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. As at December 31, 2007, OPG issued $20 million against the Lac Seul project credit facility and $210 million against the Portlands Energy Centre credit facility, which included new borrowing of $120 million under the Portlands Energy Centre facility in 2007. In January 2008, $35 million of new borrowing was issued under the Portlands Energy Centre facility.

In 2007, OPG reached an agreement with the OEFC for a $500 million general corporate facility that is available for the period June 1, 2007 to March 31, 2008, and for a $950 million credit agreement to refinance senior notes as they mature over the period September 22, 2007 to September 22, 2009. In 2007, OPG borrowed $500 million under its general corporate facility and refinanced $200 million senior notes under the $950 million credit facility. These borrowings will mature in 2017.

The non-recourse limited partnership debt is secured by a first charge on the assets of one of the joint venture limited partnerships, an assignment of the joint venture's bank accounts, and an assignment of the joint venture's project agreements. OPG's share of the total assets was $284 million as at December 31, 2007. The minimum principal repayments of the non-recourse limited partnership debt for the next five calendar years range from $7 million to $9 million annually. OPG's share of the non-recourse limited partnership debt included a note payable of $131 million at an interest rate of 6.9 per cent, with an effective interest rate of 7.0 per cent. This note payable is repayable in quarterly payments commencing March 31, 2006 to March 31, 2024. The remaining non-recourse limited partnership debt is at various floating rates. The interest rates of the floating rate debt are referenced to various interest rate indices, such as the bankers' acceptance rate and the London Interbank Offered Rate, plus a margin. The joint venture has entered into floating to fixed interest rate hedges to manage the risks arising from fluctuation in interest rates. These hedges were described under note 13 of the audited consolidated financial statements.

Interest paid in 2007 was $224 million (2006 – $247 million), of which $203 million relates to interest paid on long-term debt (2006 – $230 million).

10. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

The liabilities for fixed asset removal and nuclear waste management on a present value basis consists of the following:

(millions of dollars)	**2007**	**2006**
Liability for nuclear used fuel management	**5,938**	5,669
Liability for nuclear decommissioning and low and intermediate level waste management	**4,843**	4,659
Liability for non-nuclear fixed asset removal	**176**	192
Fixed asset removal and nuclear waste management liabilities	**10,957**	10,520

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31, 2007 and 2006 are as follows:

(millions of dollars)	**2007**	**2006**
Liabilities, beginning of year	**10,520**	8,759
Increase in liabilities due to accretion	**582**	499
Increase in liabilities due to nuclear used fuel and nuclear waste management variable expenses	**76**	38
Liabilities settled by expenditures on waste management	**(200)**	(164)
(Increase) decrease in the liability for non-nuclear fixed asset removal	**(21)**	2
Increase in the liability for nuclear used fuel management and the liability for nuclear decommissioning and low and intermediate level waste management to reflect the change in cost estimates	**-**	1,386
Liabilities, end of year	**10,957**	10,520

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and fossil-fuelled generating plant facilities. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material. Nuclear station decommissioning consists of original placement of stations into a safe store condition followed by a nominal 30-year store period prior to station dismantling.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and fossil-fuelled production facilities at the end of their useful lives;
- The present value of the fixed cost portion of any nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations; and
- The present value of the variable cost portion of any nuclear waste management program taking into account actual waste volumes generated to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. As at December 31, 2006, OPG updated the estimates for the nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management liabilities. The resulting updated Reference Plan, the 2006 Approved Reference Plan, was approved by the Province in accordance with the terms of the ONFA. The increase in cost estimates reflected in the 2006 Approved Reference Plan was mainly due to additional used fuel and waste quantities resulting from station life extensions, recent experience in decommissioning reactors, and changes in economic indices. The increase is partially offset by the impact of later end of life dates for some stations such as the Bruce A nuclear generating station and Units 1 and 4 at the Pickering nuclear generating station, which results in a later decommissioning dates and a reduced present value of decommissioning costs.

As a result of the approval of the 2006 Approved Reference Plan, OPG will recognize additional expenses including accretion on the fixed asset removal and nuclear waste management liabilities and depreciation of the carrying value of the related fixed assets. The impact of these additional expenses will be reduced by the recognition of a regulatory asset to be recovered through future prices charged to customers, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario). This is discussed in Note 7 to the consolidated financial statements.

For the purposes of calculating OPG's fixed asset removal and nuclear management liabilities, nuclear and fossil-fuelled plant closures are projected to occur over the next five to 29 years. End of life dates may change as decisions on life extensions are made. The 2006 Approved Reference Plan includes cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shutdown and to 2065 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The undiscounted amount of estimated future cash flows associated with the liabilities is approximately $24 billion in December 31, 2007 dollars. The discount rate used to calculate the present value of the liabilities was 5.75 per cent for liabilities established prior to December 31, 2006. The increase in cost estimates related to the 2006 Approved Reference Plan and subsequent increases to the value of the undiscounted estimated cash flows for OPG's liability for nuclear waste management and decommissioning are discounted at 4.6 per cent. The cost escalation rates ranged from 1.8 per cent to 3.6 per cent. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal Nuclear Fuel Waste Act ("NFWA") released in 2002 required that Canada's nuclear fuel waste owners form a Nuclear Waste Management Organization ("NWMO") and that each waste owner establish a trust fund for used fuel management costs. The NWMO studied alternatives for used fuel management and submitted an options study to the federal government in November 2005. The submission included a proposal titled Adaptive Phased Management for used fuel with an end-point being a deep geologic repository. In June 2007, the Government of Canada announced its decision to accept the NWMO proposal. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the approved Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository in-service date in 2035.

Liability for Nuclear Decommissioning and Low and Intermediate Level Waste Management Costs

The liability for nuclear decommissioning and low and intermediate level waste management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis where the reactors will remain in a safe storage state for a 30-year period prior to a 10-year dismantlement period.

The life cycle costs of low and intermediate level waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term management of these wastes. The current assumptions used to establish the accrued low and intermediate level waste management costs include a disposal facility for low and intermediate level waste with a targeted in-service date of year end 2017. Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of low and intermediate level waste adjacent to the Western Waste Management Faclity . OPG has initiated a federal environmental assessment process in respect of this proposed facility

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal is based on third-party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. This liability represents the estimated costs of decommissioning fossil-fuelled generating stations at the end of their service lives. The estimated retirement date of these stations is between 2012 and 2034.

In addition to the $107 million liability for active sites, OPG also has an asset retirement obligation liability of $69 million for decommissioning and restoration costs associated with plant sites that have been divested or are no longer in use.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities. Also, the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Ontario Nuclear Funds Agreement

OPG sets aside funds to be used specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In July 2003, OPG and the Province completed arrangements, pursuant to the ONFA. To comply with the ONFA, OPG established the Nuclear Funds. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. As at December 31, 2007, the Decommissioning Fund was in an overfunded position. OPG bears the risk and liability for cost estimate increases and fund earnings in the Decommissioning Fund.

The Used Fuel Fund will be used to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability for cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $9.6 billion in December 31, 2007 dollars based on used fuel bundle projections of 2.23 million bundles consistent with the station lives included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million as projected in the 2006 Approved Reference Plan.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2007 under the ONFA was $454 million, including a contribution to The Ontario NFWA Trust (the "Trust") of $100 million. In 2007, OPG also made a one-time contribution of approximately $334 million to the Used Fuel Fund to satisfy the extraordinary payment specified within the ONFA and related to the Bruce Lease transaction with Bruce Power as discussed in Note 18 to the audited consolidated financial statements. This payment constitutes a Triggering Event under the ONFA which results in the need to further update the Amended Payment Schedule approved by the Province earlier in 2007 as part of the initial update to the 2006 Approved Reference Plan. The update to the payment schedule is currently in progress.

The NFWA was proclaimed into force in November 2002. In accordance with the NFWA, the Nuclear Waste Management Organization was formed. The NWMO prepared and reviewed alternatives, and provided recommendations to the federal government for long-term management of nuclear fuel waste in November 2005. The federal government selected the recommended option titled Adaptive Phased Management in June 2007. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA also required OPG to make annual contributions of $100 million to the Trust. These contributions are to be deposited into the Trust no later than the November anniversary of the NFWA. The deposit amounts will be adjusted when the Mininster of Natural Resources approves the funding formula to be proposed by the NWMO in the first quarter of 2008. Given that the Trust forms part of the Used Fuel Fund, contributions to the Trust, as required by the NFWA, are applied towards the ONFA payment obligations.

As required by the *Nuclear Safety and Control Act* (Canada), and under the terms of the ONFA, the Province provided a Provincial Guarantee to the Canadian Nuclear Safety Commission ("CNSC") since 2003, on behalf of OPG. The Nuclear Safety and Control Act requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee will supplement the Used Fuel Fund and the Decommissioning Fund until they have accumulated sufficient funds to cover the accumulated liabilities for nuclear decommissioning and waste management. The current value of this guarantee is for $760 million for years 2008 to 2010. Current plans indicate the Provincial Guarantee will not be required beyond 2010. The guarantee, taken together with the Used Fuel Fund and Decommissioning Fund, was in satisfaction of OPG's nuclear licensing requirements with the CNSC. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount guaranteed by the Province. In 2007, OPG paid the annual guarantee fee of $8 million (2006 – $8 million). These fees are associated with the Provincial Guarantee of $1,510 million, which was required at that time.

Effective January 1, 2007, OPG adopted the CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement. As a result of the adoption of this new section, the investments in the Nuclear Funds and the corresponding payables to the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's consolidated financial statements.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA reference plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher estimated decommissioning liability.

At December 31, 2006, based on the estimate of costs to complete under the 2006 Approved Reference Plan, the Decommissioning Fund was overfunded on a fair value basis, and underfunded on an amortized cost basis. As a result of the adoption of the financial instruments accounting standards on January 1, 2007, OPG adjusted the investments and the related payables in the Decommissioning Fund to fair value, and recorded a transition adjustment of $519 million to increase opening retained earnings. Subsequently, the investments and the related payables in the Decommissioning Fund are measured at fair value and any changes to the fair values are recognized in income.

Since the Decommissioning Fund was underfunded on an amortized cost basis, no excess adjustment was reported in the Decommissioning Fund as at December 31, 2006. If the investments in the Decommissioning Fund were accounted for at fair value in the consolidated financial statements as at December 31, 2006, and the Decommissioning Fund was terminated under the ONFA, there would have been an amount due to the Province of $294 million.

After the adjustment to reflect the investments at fair value, on January 1, 2007 the value of the investments in the Decommissioning Fund exceeded the estimated completion costs under the 2006 Approved Reference Plan, and accordingly, the Decommissioning Fund balance was reduced by the amount of the excess funding through the recording of a payable to the Province. The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its earnings at 5.15 per cent, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status. If the Decommissioning Fund were underfunded, the earnings for the Decommissioning Fund would reflect actual fund returns based on the market value of the assets.

At December 31, 2007, the Decommissioning Fund's asset value on a fair value basis was $5,075 million, which continued to exceed the value of the liability as per the 2006 Approved Reference Plan. As a result of the overfunded status, OPG reported a payable to the Province of $3 million reflecting an amount due to the Province if the Decommissioning Fund were terminated under ONFA. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent to be treated as a contribution to the Used Fuel Fund, and the OEFC would be entitled to a distribution of an equal amount.

The assets in the Decommissioning Fund are invested primarily in publicly traded fixed income and equity investments. As a result, the value of these investments is subject to volatility in the capital markets. The volatility of the returns on these investments has increased over the past few months, which has resulted in a negative impact on the fair value and the funding status of the Decommissioning Fund. During the period January 1, 2008, to February 26, 2008, the fair value decreased by approximately 2 per cent, which resulted in a loss of approximately $100 million. The Decommissioning Fund has been designed to meet long-term liability requirements, and, therefore, short-term market variations are inevitable.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") for funding related to the first 2.23 million used fuel bundles. OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province.

Up until December 31, 2006, OPG accounted for the investments in the Used Fuel Fund on an amortized cost basis, with the amount due to or due from the Province being recorded in the consolidated financial statements as the difference between the committed return and the actual return based on realized returns. At December 31, 2006, the Used Fuel Fund included an amount due to the Province of $100 million. The Used Fuel Fund's asset value, after taking into account the committed return and the amount due to the Province, was $3,238 million at December 31, 2006.

In addition, under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Commencing January 1, 2007, the value of the investments held in the Used Fuel Fund is measured at fair value. Accordingly, the Used Fuel Fund's balance increased to $3,876 million to reflect the fair value measurement. The Province guarantees OPG's annual return in the Used Fuel Fund related to the initial 2.23 million used fuel bundles at the committed return, such that any difference between the committed return and the actual return based on fair value would be offset by the change in the related payable or receivable to the Province in the Used Fuel Fund. As a result, OPG did not record a transition adjustment to opening retained earnings for the Used Fuel Fund.

As at December 31, 2007, the Used Fuel Fund asset value on a fair value basis was $4,702 million. The asset value was offset by a payable to the Province of $511 million related to the committed return adjustment.

The nuclear fixed asset removal and nuclear waste management funds as at December 31, 2007 and 2006, consist of the following:

	Fair Value		**Amortized Cost**
(millions of dollars)	**2007**	**2006**	**2006**
Decommissioning Fund	**5,075**	5,169	4,356
Due to Province – Decommissioning Fund	**(3)**	(294)	-
	5,072	4,875	4,356
Used Fuel Fund[1]	**4,702**	3,879	3,338
Due to Province – Used Fuel Fund	**(511)**	(641)	(100)
	4,191	3,238	3,238
	9,263	8,113	7,594

[1] The Ontario NFWA Trust represented $1,244 million as at December 31, 2007 of the Used Fuel Fund on a fair value basis. The Ontario NFWA Trust represented $1,102 million as at December 31, 2006 of the Used Fuel Fund on an amortized cost and fair value basis.

The amortized cost and fair value of the securities invested in the Nuclear Funds, which include the Used Fuel Fund and Decommissioning Fund, as at December 31, 2007 and 2006 are as follows:

	Fair Value		Amortized Cost
(millions of dollars)	**2007**	**2006**	**2006**
Cash and cash equivalents and short-term investments	**833**	553	556
Marketable equity securities	**5,391**	5,608	4,250
Bonds and debentures	**3,559**	2,305	2,306
Receivable from the OEFC	**-**	588	588
Administrative expense payable	**(6)**	(6)	(6)
	9,777	9,048	7,694
Due to Province – Decommissioning Fund	**(3)**	(294)	-
Due to Province – Used Fuel Fund	**(511)**	(641)	(100)
Total	**9,263**	8,113	7,594

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31, 2007 and 2006 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2007**	**2006**
Less than 1 year	**-**	-
1 – 5 years	**1,631**	1,167
5 – 10 years	**879**	467
More than 10 years	**1,049**	671
Total maturities of debt securities	**3,559**	2,305
Average yield	**4.9%**	4.5%

The receivable of $588 million in 2006 from the OEFC was repaid in 2007. The effective rate of interest on the OEFC receivable was 3.9 per cent in 2006.

The change in the Nuclear Funds for the years ended December 31, 2007 and 2006 are as follows:

(millions of dollars)	**2007**	**Amortized Cost 2006**
Decommissioning Fund at amortized cost, beginning of year	**4,356**	4,099
Transition adjustment to fund on adoption of financial instruments accounting standards	**519**	-
Increase in fund due to return on investments	**5**	256
Decrease in fund due to reimbursement of expenditures	**(99)**	(6)
Decrease in Due to Province	**291**	7
Decommissioning Fund, end of year	**5,072**	4,356
Used Fuel Fund, beginning of year	**3,238**	2,689
Increase in fund due to contributions made	**788**	454
Increase in fund due to return on investments	**55**	204
Decrease in fund due to reimbursement of expenditures	**(20)**	(13)
Decrease (increase) in Due to Province	**130**	(96)
Used Fuel Fund, end of year	**4,191**	3,238

11. INCOME TAXES

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that the future income taxes are expected to be recovered or refunded through future regulated prices charged to customers.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2007**	**2006**
Income before income taxes	**477**	576
Combined Canadian federal and provincial statutory income tax rates, including surtax	**36.1%**	36.1%
Statutory income tax rates applied to accounting income	**172**	208
Decrease in income taxes resulting from:		
Lower future tax rate on temporary differences	**(10)**	(4)
Non-taxable income items	**(7)**	(5)
Unrecorded future income tax related to regulated operations	**(127)**	(89)
Change in income tax positions	**(13)**	10
Changes in future tax rate	**(66)**	(34)
	(223)	(122)
Income tax (recovery) expense	**(51)**	86
Effective rate of income taxes	**(10.7%)**	14.9%

The Company has revised its future income tax assets and liabilities to reflect the lower federal income tax rates recently enacted.

In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998*. Although OPG has subsequently resolved some of these issues, there is uncertainty as to how the remaining issues will be resolved. OPG expects to receive a reassessment for its 1999 taxation year. The Company would defend its position through the tax appeals process.

OPG has previously recorded income tax charges related to certain income tax positions that the Company has taken in prior years that may be disallowed. Given the uncertainty as to how these income tax matters will be resolved, OPG has not adjusted its income tax liabilities. Should the ultimate outcome materially differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its earnings could be affected positively or negatively in the period in which the matters are resolved.

Significant components of the income tax (recovery) expense are presented in the table below:

(millions of dollars)	**2007**	**2006**
Current income tax expense	**1**	60
Future income tax expense (benefits):		
Change in temporary differences	**(2)**	-
Non-capital loss carry-forward	**-**	52
Changes in future tax rate	**(30)**	-
Other	**(20)**	(26)
	(52)	26
Income tax (recovery) expense	**(51)**	86

The income tax effects of temporary differences that give rise to future income tax assets and liabilities as at December 31, 2007 and 2006 are presented in the table below:

(millions of dollars)	**2007**	**2006**
Future income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**22**	29
Other liabilities and assets	**125**	107
Non-capital loss carry-forward	**-**	28
Future recoverable Ontario minimum tax	**87**	64
	234	228
Future income tax liabilities:		
Fixed assets	**263**	332
Other liabilities and assets	**176**	145
	439	477
Net future income tax liabilities	**205**	249
Represented by:		
Current portion (asset) liability	**(12)**	3
Long-term portion	**217**	246
	205	249

The following table summarizes the difference in the consolidated statements of income and consolidated statements of comprehensive income under the taxes payable method used by the Company to account for income taxes for the regulated businesses compared to what would have been reported had OPG applied the liability method for the regulated businesses for 2007 and 2006:

(millions of dollars)	**2007**	**2006**
As stated:		
Future income tax expense	**(52)**	26
Future income tax: Other comprehensive income – upon transition	**16**	-
Future income tax: Other comprehensive income – for the period	**(8)**	-
Liability method[1]:		
Future income tax expense	**75**	115
Future income tax: Other comprehensive income – upon transition	**12**	-
Future income tax: Other comprehensive income – for the period	**(6)**	-

[1] OPG accounts for certain lease revenues relating to the regulated businesses using the cash basis of accounting. The related future income tax impact is excluded from the above.

The following table summarizes the difference in the consolidated balance sheet amounts under the taxes payable method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business as at December 31, 2007 and 2006:

	2007		**2006**	
(millions of dollars)	**As Stated**	**Liability Method[1]**	**As Stated**	**Liability Method[1]**
Current future income tax recoverable (liabilities)	**12**	**39**	(3)	(4)
Long-term future income tax liabilities	**(217)**	**(680)**	(246)	(417)

[1] OPG accounts for certain lease revenues relating to the regulated businesses using the cash basis of accounting. The related future income tax impact is excluded from the above.

The amount of cash income taxes paid for 2007 was $64 million (2006 – $24 million).

12. Benefit Plans

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. The registered pension plan is a contributory defined benefit plan covering most employees and retirees. Pension fund assets include equity securities and corporate and government debt securities, real estate and other investments which are managed by professional investment managers. The fund does not invest in equity or debt securities issued by OPG. The supplementary pension plans are defined benefit plans covering certain employees and retirees.

Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The pension and OPEB obligations, and the pension fund assets, are measured at December 31, 2007.

	Registered and Supplementary Pension Plans		**Other Post Employment Benefits**	
	2007	**2006**	**2007**	**2006**
Weighted Average Assumptions – Benefit Obligation at Year End				
Rate used to discount future benefits	**5.60%**	5.25%	**5.59%**	5.22%
Salary schedule escalation rate	**3.25%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.25%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.91%**	7.34%
Ultimate health care trend rate	**-**	-	**4.68%**	4.68%
Year ultimate rate reached	**-**	-	**2014**	2014
Rate of increase in disability benefits	**-**	-	**2.25%**	2.00%

	Registered and Supplementary Pension Plans		**Other Post Employment Benefits**	
	2007	**2006**	**2007**	**2006**
Weighted Average Assumptions – Cost for the Year				
Expected return on plan assets net of expenses	**7.00%**	7.00%	**-**	-
Rate used to discount future benefits	**5.25%**	5.00%	**5.22%**	4.97%
Salary schedule escalation rate	**3.00%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**7.34%**	7.76%
Ultimate health care trend rate	**-**	-	**4.68%**	4.68%
Year ultimate rate reached	**-**	-	**2014**	2014
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%
Average remaining service life for employees (years)	**11**	11	**11**	11

(millions of dollars)	Registered Pension Plan 2007	2006	Supplementary Pension Plans 2007	2006	Other Post Employment Benefits 2007	2006
Changes in Plan Assets						
Fair value of plan assets at beginning of year	**8,829**	7,921	**-**	-	**-**	-
Contributions by employer	**268**	261	**7**	7	**66**	62
Contributions by employees	**66**	61	**-**	-	**-**	-
Actual return on plan assets net of expenses	**159**	945	**-**	-	**-**	-
Benefit payments	**(398)**	(359)	**(7)**	(7)	**(66)**	(62)
Fair value of plan assets at end of year	**8,924**	8,829	**-**	-	**-**	-
Changes in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	**9,313**	9,095	**152**	144	**2,067**	2,065
Employer current service costs	**224**	212	**6**	6	**70**	71
Contributions by employees	**66**	61	**-**	-	**-**	-
Interest on projected benefit obligation	**493**	459	**8**	7	**109**	104
Past service costs	**-**	-	**-**	-	**-**	13
Benefit payments	**(398)**	(359)	**(7)**	(7)	**(66)**	(62)
Net actuarial loss (gain)	**(95)**	(155)	**3**	2	**(116)**	(124)
Projected benefit obligation at end of year	**9,603**	9,313	**162**	152	**2,064**	2,067
Funded Status – Deficit at end of year	**(679)**	(484)	**(162)**	(152)	**(2,064)**	(2,067)

The assets of the OPG pension fund are allocated among three principal investment categories. Furthermore, equity investments are diversified across Canadian, U.S. and non-North American stocks. The fund also has a small real estate portfolio that is less than one per cent of plan assets.

	2007	2006
Registered pension plan fund asset investment categories		
Equities	**60%**	67%
Fixed income	**35%**	30%
Cash and short-term investments	**5%**	3%
Total	**100%**	100%

Based on the most recently filed actuarial valuation, as at January 1, 2005, there was an unfunded liability on a going-concern basis of $465 million and a deficiency on a wind-up basis of $1,979 million. The deficit disclosed in the next filed funding valuation, which must have an effective date no later than January 1, 2008, could be significantly different.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $175 million (2006 – $159 million).

(millions of dollars)	Registered Pension Plan 2007	Registered Pension Plan 2006	Supplementary Pension Plans 2007	Supplementary Pension Plans 2006	Other Post Employment Benefits 2007	Other Post Employment Benefits 2006
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)						
Funded status – deficit at end of year	**(679)**	(484)	**(162)**	(152)	**(2,064)**	(2,067)
Unamortized net actuarial loss	**1,346**	1,108	**22**	20	**538**	699
Unamortized past service costs	**64**	82	**3**	3	**20**	25
Accrued benefit asset (liability) at end of year	**731**	706	**(137)**	(129)	**(1,506)**	(1,343)
Short-term portion	**-**	-	**(7)**	(6)	**(80)**	(70)
Long-term portion	**731**	706	**(130)**	(123)	**(1,426)**	(1,273)

(millions of dollars)	Registered Pension Plan 2007	Registered Pension Plan 2006	Supplementary Pension Plans 2007	Supplementary Pension Plans 2006	Other Post Employment Benefits 2007	Other Post Employment Benefits 2006
Components of Cost Recognized						
Current service costs	**224**	212	**6**	6	**70**	71
Interest on projected benefit obligation	**493**	459	**8**	7	**109**	104
Expected return on plan assets net of expenses	**(569)**	(551)	**-**	-	**-**	-
Amortization of past service costs	**18**	18	**-**	1	**5**	4
Amortization of net actuarial loss	**77**	80	**1**	-	**45**	62
Cost recognized	**243**	218	**15**	14	**229**	241

(millions of dollars)	Registered Pension Plan 2007	Registered Pension Plan 2006	Supplementary Pension Plans 2007	Supplementary Pension Plans 2006	Other Post Employment Benefits 2007	Other Post Employment Benefits 2006
Components of Cost Incurred and Recognized						
Current service costs	**224**	212	**6**	6	**70**	71
Interest on projected benefit obligation	**493**	459	**8**	7	**109**	104
Actual return on plan assets net of expenses	**(159)**	(945)	**-**	-	**-**	-
Past service costs	**-**	-	**-**	-	**-**	13
Net actuarial (gain) loss	**(95)**	(155)	**3**	2	**(116)**	(124)
Cost incurred in year	**463**	(429)	**17**	15	**63**	64
Differences between costs incurred and recognized in respect of:						
Actual return on plan assets net of expenses	**(410)**	394	**-**	-	**-**	-
Past service costs	**18**	18	**-**	1	**5**	(9)
Net actuarial loss (gain)	**172**	235	**(2)**	(2)	**161**	186
Cost recognized	**243**	218	**15**	14	**229**	241

A one per cent increase or decrease in the health care trend rate would result in an increase in the service and interest components of the 2007 OPEB cost recognized of $37 million (2006 – $34 million) or a decrease in the service and interest components of the 2007 OPEB cost recognized of $29 million (2006 – $26 million), respectively. A one per cent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2007 of $328 million (2006 – $342 million) or a decrease in the projected OPEB obligation at December 31, 2007 of $256 million (2006 – $265 million).

13. FINANCIAL INSTRUMENTS

Risk Management and Hedging Activities

OPG is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the wholesale price of electricity, OPG enters into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized in income when the underlying hedged transactions occur. These gains or losses are included in unregulated revenue and are recorded on the consolidated balance sheets. All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in other revenue.

OPG also enters into derivative contracts with major financial institutions to manage the Company's exposure to foreign currency movements. Foreign exchange translation gains and losses on these foreign currency denominated derivative contracts are recognized as an adjustment to the purchase price of the commodity or goods received.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded through net income in the period incurred.

OPG utilizes ERCs and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances are held in inventory and charged to OPG's operations at average cost as part of fuel expense as required. Options to purchase ERCs are accounted for as derivatives and are recorded at estimated market value.

Equity price risk is the risk of loss due to volatility in the prices of individual equity instruments and equity indices. The holdings of OPG's Nuclear Funds and pension fund include publicly traded equity investments. As a result, the value of these investments is subject to capital market volatility. This risk can impact the value of the investments held by OPG's Nuclear Funds and pension fund.

To manage this risk, OPG's Nuclear Funds and pension fund have investment policies and procedures in place to set out the investment framework of the funds, including the investment assumptions, permitted investments, and various investment constraints. Such policies and procedures are approved annually by OPG's Investment Funds Oversight Committee of the Board of Directors. For the Nuclear Funds, such policies and procedures are also agreed to jointly with the Province, under ONFA.

Hedge Accounting

At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. OPG also requires a documented assessment, both at hedge inception and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. When a derivative hedging relationship is expired, the designation of a hedging relationship is terminated, or a portion of the hedging instrument is no longer effective, any associated gains or losses included in AOCI are recognized in income in the current period's consolidated statement of income.

Determination of Fair Value

Fair values of derivative instruments have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG considers various factors to estimate forward prices, including market prices and price volatility in neighbouring electricity markets, market prices for fuel, and other factors.

Forward pricing information is inherently uncertain so that fair values of derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions.

Derivative Instruments Qualifying for Hedge Accounting

The following table provides the estimated fair value of derivative instruments designated as hedges. The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized in net income upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

(millions of dollars except where noted)	**Notional Quantity**	**Terms 2007**	**Fair Value**	**Notional Quantity**	**Terms 2006**	**Fair Value**
Gain (loss)						
Electricity derivative instruments	**1.8 TWh**	**1-3 yrs**	**35**	4.3 TWh	1-4 yrs	51
Foreign exchange derivative instruments	**U.S. $48**	**Sep./08**	**(1)**	U.S. $2	Jan./07	-
Floating to fixed interest rate hedges	**43**	**1-11 yrs**	**(2)**	45	1-12 yrs	(3)
Forward start interest rate hedges	**692**	**1-12 yrs**	**(6)**	622	1-14 yrs	(9)

Foreign exchange derivative instruments are used to hedge the exposure to anticipated U.S. dollar denominated purchases. The weighted average fixed exchange rate for contracts outstanding at December 31, 2007 was U.S. $1.00 (2006 – U.S. $0.87) for every Canadian dollar.

One of the Company's joint ventures is exposed to changes in interest rates. The joint venture entered into an interest rate swap to manage the risk arising from fluctuations in interest rates by swapping the short-term floating interest rate with a fixed rate of 5.33 per cent. OPG's proportionate interest in the swap is 50 per cent and is accounted for as a hedge.

OPG entered into a number of forward start interest rate swap agreements to hedge against the effect of future interest rate movements based on the anticipated future borrowing requirement for the Niagara Tunnel and the Portlands Energy Centre projects, and OPG's general corporate facility. Although these transactions are ordinarily accounted for as hedges, a gain of approximately $3 million was recorded to account for ineffectiveness in the hedges for 2006.

In 2007, OPG has de-designated a number of forward start interest rate hedges as the previously anticipated future borrowings associated with these instruments were no longer expected to occur. As a result of the de-designation, a gain of $1 million was reclassified to net income in 2007.

Net gains of $15 million related to derivative instruments qualifying for hedge accounting were recognized in net income in 2007. These amounts were previously recorded in other comprehensive income.

Existing net gains of $20 million deferred in accumulated other comprehensive income as at December 31, 2007 are expected to be reclassified to net income within the next 12 months.

Derivative Instruments Not Qualifying for Hedge Accounting

The carrying amount (fair value) of derivative instruments not designated for hedging purposes is as follows:

(millions of dollars except where noted)	Notional Quantity 2007	Fair Value 2007	Notional Quantity 2006	Fair Value 2006
Foreign exchange derivative instruments	**U.S.$14**	**(2)**	-	-
Commodity derivative instruments				
Assets	**9.9 TWh**	**14**	3.9 TWh	25
Liabilities	**1.2 TWh**	**(10)**	2.6 TWh	(25)
		2		-
Market liquidity reserve		**(2)**		(2)
Total		**-**		(2)

Foreign exchange derivative instruments that are not designated as hedges have a weighted average exchange rate of U.S. $0.86 at December 31, 2007.

Fair Value of Other Financial Instruments

The carrying values of financial instruments such as in cash and cash equivalents, accounts receivable, long-term accounts receivable and other assets, accounts payable and accrued charges, and long-term accounts payable and accrued charges approximate their fair values. Fair values for other financial instruments have been estimated by reference to quoted market prices for actual or similar instruments where available.

The carrying values and fair values of these other financial instruments as at December 31, 2007 and 2006 are as follows:

(millions of dollars)	Carrying Value 2007	Fair Value 2007	Carrying Value 2006	Fair Value 2006
Financial Assets				
Nuclear fixed asset removal and nuclear waste management funds	**9,263**	**9,263**	7,594	8,113
Financial Liabilities				
Long-term debt due within one year	**407**	**409**	406	409
Long-term debt	**3,446**	**3,502**	2,953	3,082

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. As the majority of OPG's sales are through the IESO administered spot market, OPG management accepts this credit risk due to the IESO's primary role in the Ontario electricity market. This confidence is based on the IESO's own credit risk management policies and practices, which require all spot market participants to meet specific standards for creditworthiness. Additionally, in the event of a participant default, the loss is shared on a pro-rata basis among all participants thus reducing the specific exposure to OPG.

Credit exposure to the IESO fluctuates based on spot prices and the volume of rate regulated and unregulated generation, and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at $883 million in 2007 (2006 – $1,029 million).

OPG's second element of credit risk relates to the exposures created by companies ("counterparties") who are contracted to provide services or products. OPG manages this risk using a comprehensive credit risk management function that independently evaluates all major counterparties and provides continuous input to business units who acquire these services.

14. COMMON SHARES

As at December 31, 2007 and 2006, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value.

15. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries, covering a wide range of matters, that arise in the ordinary course of its business activities.

On August 9, 2006, a Notice of Action and Statement of Claim in the amount of $500 million (the "Claim") was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited ("British Energy"), claiming that OPG is liable to them for breach of contract and negligence. OPG leased the Bruce nuclear generating stations to Bruce Power L.P. in 2001. British Energy was an investor in Bruce Power L.P. In 2003, British Energy sold its interest in Bruce Power L.P. to a group of investors (the "Purchasers"). The Purchasers are claiming that British Energy is liable to them with respect to this purchase transaction. Their claim is currently the subject of an arbitration proceeding (the "Arbitration"). British Energy is therefore suing OPG in order to preserve any similar claim it may have against OPG pursuant to the 2001 lease transaction. British Energy has indicated that it does not require OPG to actively defend the Claim at this point in time as British Energy is defending the Arbitration commenced by the Purchasers. The Arbitration may narrow or eliminate the claims or damages British Energy has, so as to narrow or eliminate the need to continue the Claim against OPG. British Energy has reserved the right to require OPG to defend the Claim prior to the conclusion of the Arbitration should British Energy at some point believe there is some advantage in doing so.

Certain First Nations have commenced actions for interference with reserve and traditional land rights. The claims by some of these First Nations total approximately $163 million and claims by others are for unspecified amounts. In 2007, OPG recorded additional expenses associated with past grievances by First Nations.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG and could have a significant effect on OPG's financial position. Management has provided for contingencies that are determined to be likely and are reasonably measurable.

Environmental

OPG was required to assume certain environmental obligations from Ontario Hydro. A provision of $76 million was established as at April 1, 1999 for such obligations. During 2007, OPG recorded expenditures of $2 million (2006 – $4 million). As at December 31, 2007, the remaining provision was $45 million (2006 – $52 million).

Current operations are subject to regulation with respect to air, soil and water quality and other environmental matters by federal, provincial and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its interim consolidated financial statements to meet OPG's current environmental obligations.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, standby Letters of Credit and surety bonds.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2007 are as follows:

(millions of dollars)	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	694	417	325	258	219	374	2,287
Contributions under the ONFA [1]	454	350	350	317	308	1,239	3,018
Long-term debt repayment	400	350	970	375	400	1,170	3,665
Interest on long-term debt	201	183	152	103	75	288	1,002
Unconditional purchase obligations	18	17	16	12	13	174	250
Long-term accounts payable	9	-	-	-	-	-	9
Operating lease obligations	12	12	13	13	13	2	65
Operating licence	20	19	21	22	22	-	104
Pension contributions [2]	260	-	-	-	-	-	260
Other	33	31	34	32	18	42	190
	2,101	1,379	1,881	1,132	1,068	3,289	10,850
Significant commercial commitments:							
Niagara Tunnel	146	258	34	-	-	-	438
Other hydroelectric projects	48	8	1	-	-	-	57
Portlands Energy Centre	59	5	3	3	3	46	119
Total	2,354	1,650	1,919	1,135	1,071	3,335	11,464

[1] Contributions under the ONFA are subject to adjustment due to the 2006 Approved Reference Plan.

[2] The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuation as at January 1, 2005. The contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, and the timing of funding valuations. Funding requirements after 2008 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The pension contributions are subject to change as a result of the filing of the actuarial valuation in 2008.

Niagara Tunnel

The Niagara Tunnel project will increase the amount of water flowing to existing turbines at OPG's Sir Adam Beck generating stations in Niagara Falls, allowing the stations to more effectively utilize available water. At December 31, 2007, the tunnel boring machine had advanced 1,609 metres. The progress of the tunnel boring machine by the design-build contractor through a fractured rock formation has been slower than expected. Considerable uncertainty remains with respect to the schedule until the tunnel boring machine advances sufficiently beyond the St. David's gorge to approximately 2,300 metres, and establishes consistent tunneling performance.

The contract structure places the onus on the contractor to mitigate schedule delays, and includes liquidated damages provisions for failure to meet the contractual in-service date.

Based on the information provided by the contractor, the in-service date of the tunnel will be delayed. To mitigate the impact of the schedule delay, the contractor is investigating alternatives, including the realignment of the tunnel. The estimated in-service date will be dependent on the alternative selected by the contractor. Considerable uncertainty remains with respect to the schedule for any of the contractor's alternatives until the tunnel boring machine has advanced beyond the St. David's gorge.

There is a potential that the schedule delay could impact the project cost. The project cost estimate of $985 million will be reviewed in conjunction with the changes to the project completion schedule and a review of actual subsurface rock conditions compared to those that were anticipated as part of the design-build contract.

The capital project expenditures for the year ended December 31, 2007 were $60 million and life-to-date capital expenditures were $303 million. The project is debt financed through the OEFC.

Lac Seul

OPG is constructing a new 12.5 MW hydroelectric generating station on the English River. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded and construction started during the first quarter of 2006. In accordance with the contractor's original schedule, the project was expected to be in-service in the fourth quarter of 2007. However, the contractor has advised OPG that the project is now expected to be in-service in the third quarter of 2008.

Life-to-date expenditures are $41 million. Total project costs are expected to be $47 million. The project is debt financed through the OEFC.

On December 20, 2007, the Ontario Government issued a directive to the Ontario Power Authority ("OPA") instructing the OPA to negotiate and execute a Hydroelectric Energy Supply Agreement for Lac Seul by January 31, 2008. The Lac Seul Hydroelectric Energy Supply Agreement was executed in January 2008.

Portlands Energy Centre

OPG entered into a partnership with TransCanada Energy Ltd., through the Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle station on the site of the former R.L. Hearn generating station, near downtown Toronto. OPG has a 50 per cent ownership interest in the joint venture.

Construction of the generating station started in 2006 and it is expected to be operational in a simple cycle mode with a capacity of up to 340 MW by June 1, 2008. The simple cycle mode will only operate as needed during the summer of 2008, after which the generating station will be taken out of service to enable construction to be completed on the combined cycle mode.

The plant is expected to be completed and fully operational in the second quarter of 2009, providing up to 550 MW of power in a combined cycle mode. Project costs are expected to be within the approved budget of $730 million excluding capitalized interest. A significant proportion of this capital cost relates to an engineer-procure-construct contract to construct the facility.

OPG's share of capital project expenditures for the year ended December 31, 2007 was $176 million. OPG's share of the life-to-date capital expenditures was $273 million. OPG's share of the project is debt financed through the OEFC.

Other Commitments

In addition to the above commitments, the Company has the following commitments:

The Company maintains labour agreements with the Power Workers' Union and The Society of Energy Professionals; the agreements are effective until March 31, 2009 and December 31, 2010, respectively. As at December 31, 2007, OPG had approximately 11,700 regular employees and approximately 90 per cent of its regular labour force is covered by the collective bargaining agreements.

Contractual and commercial commitments above exclude certain purchase orders as they represent purchase authorizations rather than legally binding contracts and are subject to change without significant penalties.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. OPG continues to discuss resolution to this issue with the Ministry of Finance as updates to the regulation may not occur for several years. OPG has not recorded any amounts relating to this anticipated regulation change.

16. REVENUE LIMIT REBATE

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, stations whose generation output is subject to a HESA with the OPA pursuant to a ministerial direction, and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets is also excluded from the output covered by the revenue limit. In addition, until the TRO expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate.

The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and it will increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the OPA are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the IESO for the benefit of consumers.

The changes in the revenue limit rebate liability are as follows:

(millions of dollars)	**2007**	**2006**
Liability, beginning of the year	**40**	739
Increase to provision during the year	**227**	161
Payments made during the year	**(167)**	(860)
Liability, end of year	**100**	40

17. OTHER GAINS AND LOSSES

(millions of dollars)	**2007**	**2006**
Impairment loss on the Thunder Bay and Atikokan coal-fired generating stations *(Note 5)*	**-**	22
Change in estimated cost required to decommission the Lakeview generating station	**(20)**	-
Impairment loss on investments in ABCP *(Note 6)*	**10**	-
Other (gains) and losses	**(10)**	22

The demolition of the former Lakeview coal-fired generating station was substantially completed during 2007. During the fourth quarter of 2007, the Company re-estimated the costs to complete the remaining work to remediate the site in 2008. As a result, OPG recorded a recovery of $20 million in other gains and losses to reflect a change in the estimated costs.

OPG conducted an analysis to determine the fair market value of its third-party ABCP holdings as at December 31, 2007. After reviewing this matter in detail, OPG recorded a write-down of $10 million. Further details on OPG's investments in third-party ABCP are disclosed in Note 6 of the consolidated annual financial statements.

18. BUSINESS SEGMENTS

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that it operates became rate regulated. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Commencing in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that OPG owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations.

OPG's Regulated – Nuclear business segment includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. The arrangement includes lease revenue, interest income and revenue from engineering analysis and design, technical and other services. The Regulated – Nuclear business segment also includes revenue earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support. These revenues are included in the Regulated – Nuclear business segment since they were included in determining the regulated price for production from the nuclear facilities operated by OPG.

Bruce Nuclear Generating Stations

In May 2001, the Company leased its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with options to renew for up to 25 years.

Under the terms of the lease, OPG agreed to transfer certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. Pension assets and liabilities related to the approximately 3,000 employees were transferred to Bruce Power. Bruce Power assumed the liability for other post employment benefits for these employees. OPG makes payments to Bruce Power in respect of other post employment benefits of approximately $2.3 million per month over a 72-month period, ending in 2008.

As part of the closing, OPG recorded deferred revenue to reflect the initial payments of $595 million less net assets transferred to Bruce Power under the lease agreement. The deferred revenue is being amortized over the initial lease term of approximately 18 years and is recorded as revenue.

In December 2002, British Energy plc. entered into an agreement to dispose of its entire 82.4 per cent interest in Bruce Power. The transaction was completed in February 2003 and a consortium of Canadian companies assumed the lease of the Bruce A and Bruce B nuclear generating stations that was formerly held by British Energy plc. The Bruce facilities will continue to be operated by Bruce Power. Upon closing of the transaction, a $225 million note receivable was paid to OPG, and lease payments commenced to be paid monthly. Proceeds from the note and applicable interest were to be applied by March 2008 against OPG's funding requirements with respect to the nuclear fixed asset removal and nuclear waste management liabilities. OPG made an extraordinary contribution of $334 million to the Used Fuel Fund in December 2007.

As part of the agreement reached in October 2005 between the Province and Bruce Power, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to accept certain amendments to the lease agreement. These amendments included a change to the provisions regarding the transfer of Bruce Power's interest in the site and included a reduction of the annual lease payment for three of the four refurbished Bruce A units to $5.5 million per unit (in 2002 dollars, escalated at Consumer Price Index, that will affect the three Bruce A units to be refurbished, once the planned future refurbishments are completed. These changes to the lease agreement will affect OPG when Units 1 and 2 of the Bruce A nuclear generating station are returned to service, and when Unit 3 is refurbished at the end of its current operational life. Other changes to the existing arrangements were made to address Cameco Corporation's decision not to participate in the refurbishment of the Bruce A nuclear generating station.

For 2004 through 2008, minimum payments under the lease are $190 million annually, subject to limited exceptions. The lease revenue of $253 million (2006 – $251 million) was recorded in revenue. The remaining terms of the operating lease agreement will remain substantially unchanged until the planned future refurbishments are completed.

The net book value of fixed assets on lease to Bruce Power at December 31, 2007 was $1,201 million (2006 – $1,273 million). The net book value at December 31, 2006 includes the impact of the increase in the nuclear fixed asset removal and nuclear waste management liabilities relating to the Bruce units as a result of the 2006 Approved Reference Plan described in Note 10 to the audited consolidated financial statements.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of OPG's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – Hydroelectric business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, automatic generation control, and revenues from other services.

Other

OPG earns revenue from its joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Coral. In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment of the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the year ended December 31, 2007, the service fee was $33 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $4 million for Unregulated – Hydroelectric and $11 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $50 million for the Other category. For the year ended December 31, 2006, the service fee was $30 million for Regulated – Nuclear, $3 million for Regulated – Hydroelectric, $4 million for Unregulated – Hydroelectric and $11 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $48 million for the Other category.

Segment (Loss) Income for the Year Ended December 31, 2007	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue	**2,581**	**695**	**763**	**1,713**	**135**	**5,887**
Revenue limit rebate	**-**	**-**	**(64)**	**(163)**	**-**	**(227)**
	2,581	**695**	**699**	**1,550**	**135**	**5,660**
Fuel expense	**133**	**244**	**81**	**812**	**-**	**1,270**
Gross margin	**2,448**	**451**	**618**	**738**	**135**	**4,390**
Operations, maintenance and administration	**2,061**	**123**	**207**	**573**	**10**	**2,974**
Depreciation and amortization	**426**	**68**	**68**	**82**	**51**	**695**
Accretion on fixed asset removal and nuclear waste management liabilities	**499**	**-**	**-**	**8**	**-**	**507**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(481)**	**-**	**-**	**-**	**-**	**(481)**
Property and capital taxes	**31**	**11**	**10**	**21**	**12**	**85**
(Loss) income before other gains and losses	**(88)**	**249**	**333**	**54**	**62**	**610**
Other (gains) and losses *(Note 17)*	**(4)**	**-**	**4**	**(20)**	**10**	**(10)**
(Loss) income before interest and income taxes	**(84)**	**249**	**329**	**74**	**52**	**620**

Segment Income (Loss) for the Year Ended December 31, 2006	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue	2,665	685	780	1,430	165	5,725
Revenue limit rebate	-	-	(44)	(117)	-	(161)
	2,665	685	736	1,313	165	5,564
Fuel expense	122	245	88	643	-	1,098
Gross margin	2,543	440	648	670	165	4,466
Operations, maintenance and administration	1,942	92	189	524	5	2,752
Depreciation and amortization	368	66	69	133	53	689
Accretion on fixed asset removal and nuclear waste management liabilities	490	-	-	9	-	499
Earnings on nuclear fixed asset removal and nuclear waste management funds	(371)	-	-	-	-	(371)
Property and capital taxes	44	18	15	19	10	106
Income (loss) before other gains and losses	70	264	375	(15)	97	791
Other (gains) and losses *(Note 17)*	-	-	-	22	-	22
Income (loss) before interest and income taxes	70	264	375	(37)	97	769

(millions of dollars)	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
Selected Balance Sheet Information						
As at December 31, 2007						
Segment fixed assets in service, net	**4,030**	**3,871**	**2,996**	**422**	**508**	**11,827**
Segment construction work in progress	**210**	**299**	**88**	**322**	**31**	**950**
Segment property, plant and equipment, net	**4,240**	**4,170**	**3,084**	**744**	**539**	**12,777**
Segment materials and supplies inventory, net:						
Short-term	**73**	**1**	**-**	**51**	**-**	**125**
Long-term	**346**	**-**	**3**	**4**	**-**	**353**
Segment fuel inventory	**231**	**-**	**-**	**373**	**-**	**604**
As at December 31, 2006						
Segment fixed assets in service, net	4,213	3,907	3,012	408	544	12,084
Segment construction work in progress	165	252	78	145	37	677
Segment property, plant and equipment, net	4,378	4,159	3,090	553	581	12,761
Segment materials and supplies inventory, net:						
Short-term	63	1	-	48	-	112
Long-term	320	-	3	3	-	326
Segment fuel inventory	183	-	-	486	-	669
Selected Cash Flow Information						
Year ended December 31, 2007 Investment in fixed assets	**207**	**80**	**66**	**270**	**43**	**666**
Year ended December 31, 2006 Investment in fixed assets	173	171	81	71	141	637

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. (“Hydro One”), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

(millions of dollars)	Revenue 2007	Expenses 2007	Revenue 2006	Expenses 2006
Hydro One				
Electricity sales	**28**	**-**	34	-
Services	**-**	**12**	-	13
Province of Ontario				
GRC water rentals and land tax	**-**	**129**	-	132
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**(130)**	-	96
Decommissioning Fund excess funding	**-**	**(291)**	-	(7)
OEFC				
GRC and proxy property tax	**-**	**199**	-	205
Interest income on receivable	**-**	**(6)**	-	(29)
Interest expense on long-term notes	**-**	**187**	-	203
Capital tax	**-**	**32**	-	51
Income taxes	**-**	**(51)**	-	86
Indemnity fees	**-**	**-**	-	2
IESO				
Electricity sales	**5,094**	**104**	5,029	146
Revenue limit rebate	**(227)**	**-**	(161)	-
Ancillary services	**145**	**-**	132	-
Other	**-**	**1**	1	1
	5,040	**194**	5,035	907

During 2006, OPG's Board of Directors approved the payment of a dividend to its shareholder, the Province. The declared dividend of $128 million represents 35 per cent of OPG's 2005 net income and was paid in November 2006.

At December 31, 2007, accounts receivable included $2 million (2006 – $8 million) due from Hydro One and $211 million (2006 – $71 million) due from the IESO. Accounts payable and accrued charges at December 31, 2007 included $2 million (2006 – $2 million) due to Hydro One.

20. JOINT VENTURES

Significant joint ventures include Brighton Beach and PEC, which are 50 per cent owned by OPG.

The following condensed information from the consolidated statements of operations, cash flows and balance sheets detail the Company's share of its investments in joint ventures and partnerships that has been proportionately consolidated:

(millions of dollars)	**2007**	**2006**
Proportionate joint venture operations		
Operating revenue	**43**	39
Operating expenses	**(24)**	(19)
Net income	**19**	20
Proportionate joint venture cash flows		
Operating activities	**1**	17
Investing activities	**(165)**	(109)
Financing activities	**164**	(6)
Share of changes in cash	**-**	(98)
Proportionate joint venture balance sheets		
Current assets	**38**	25
Long-term assets	**533**	379
Current liabilities	**(24)**	(25)
Long-term liabilities	**(185)**	(191)
Share of net assets	**362**	188

21. INVESTMENT COMPANY

The Company applied AcG-18 for all investments owned by OPGV. OPGV is a wholly owned subsidiary of the Company and its results are included into the Company's consolidated financial statements. The carrying amount of OPGV's investments was $45 million (2006 – $32 million) and the amount was included as long-term accounts receivable and other assets on the consolidated balance sheets.

As a result of the application of this policy, the Company's net income and other assets for 2007 increased by $13 million (2006 – $2 million). The net realized gains and losses for OPGV was nil in 2007 (2006 – $1 million).

The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2007 were $19 million and $15 million, respectively. The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2006 were $5 million and $14 million, respectively.

22. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2007, $88 million (2006 – $66 million) of research and development expenses were charged to operations.

23. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**2007**	**2006**
Accounts receivable	**(97)**	303
Prepaid expenses	**(9)**	-
Fuel inventory	**65**	(88)
Materials and supplies	**(13)**	-
Revenue limit rebate payable	**227**	161
Accounts payable and accrued charges	**(42)**	54
Income and capital taxes payable	**(62)**	47
	69	477

ONTARIO POWER GENERATION

2007 REPORT

CONTENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2007. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. Certain of the 2006 comparative amounts have been reclassified to conform to the 2007 presentation. This MD&A is dated February 28, 2008.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

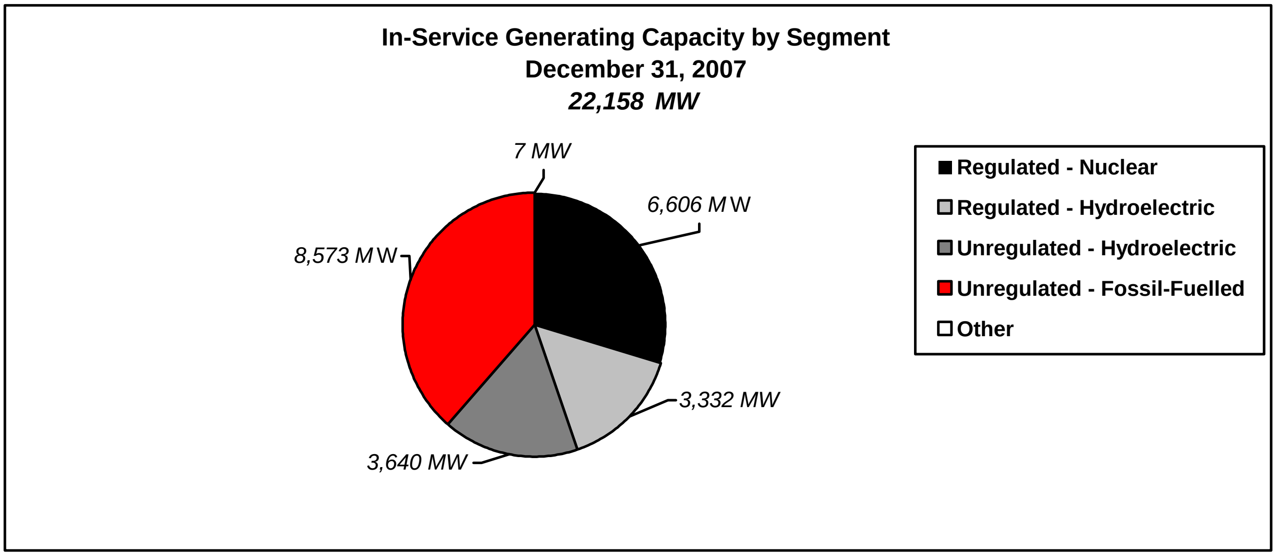
All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, asset performance, nuclear decommissioning and waste management, closure of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post employment benefit ("OPEB") obligations, income taxes, spot electricity market prices, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, the weather, and the developments with respect to third-party Asset-Backed Commercial Paper. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

At December 31, 2007, OPG's electricity generating portfolio had an in-service capacity of 22,158 megawatts ("MW"). OPG's electricity generating portfolio consists of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (including a 50 per cent interest in the Huron Wind joint venture, which was subsequently sold in February 2008). In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach gas-fired generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that the Company operates became rate regulated. OPG receives the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit on the majority of this output.



RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004* (Ontario), which provides that, effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours ("MWh") of production from the regulated hydroelectric facilities in any hour is $33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric electricity production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the Ontario electricity spot market price. The regulated price received by OPG for production from the nuclear facilities is $49.50/MWh (4.95¢/kWh). These regulated prices were established by the Province, based on a revenue requirement taking into account a forecast of production volumes and total operating costs, and a return on rate base, which assumed an average five per cent return on equity. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets and an allowance for working capital. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, after which time the Ontario Energy Board ("OEB") will assume responsibility for establishing new regulated prices.

The regulation directed OPG to establish variance accounts for costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices. Variance accounts have been established for differences in hydroelectric electricity production due to differences between forecast and actual water conditions; unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear facilities; changes to revenues for ancillary services from the regulated facilities; acts of God (including severe weather events); and transmission outages and transmission restrictions. In addition, the regulation directed OPG to establish a deferral account for non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A nuclear generating station.

An amendment to the regulation was made by the Province in February 2007. The amendment clarified certain aspects of the regulation and directed OPG to establish a deferral account related to certain changes in its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management. The amendment directed OPG to establish a deferral account to record, up to the effective date of the OEB's first order establishing regulated prices, the revenue requirement impact of any changes in its nuclear liabilities arising from a new reference plan, approved after April 1, 2005, in accordance with the terms of the Ontario Nuclear Funds Agreement ("ONFA").

The amendment also clarified that the OEB must ensure that OPG recovers, through future regulated prices, all capital and non-capital costs incurred by OPG in order to increase the output of, refurbish, or add operating capacity to a regulated facility. The amendment requires these costs be within budgets approved by OPG's Board of Directors prior to the OEB's first order establishing regulated prices, or that the OEB is satisfied that these costs were prudently incurred.

In February 2008, a second amendment to the regulation was made by the Province. This amendment directs OPG to establish a deferral account to record, for the period up to the effective date of the OEB's first order, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities. This amendment further directs OPG to establish a variance account to record, for the period on or after the effective date of the OEB's first order, the differences between actual non-capital costs incurred and firm financial commitments made, and the amounts included in the approved regulated price related to planning and preparation for the development of proposed new nuclear generation facilities. In addition, the amendment states that the OEB must ensure that OPG recovers these costs to the extent the OEB is satisfied that the costs were prudently incurred or commitments prudently made.

In November 2007, OPG filed an application with the OEB for new payment amounts for its regulated facilities effective April 1, 2008, for a 21-month period. OPG invited stakeholders to participate in consultation sessions, which occurred in early November, in advance of filing this application. The intent of the consultations was to inform stakeholders about OPG's regulated facilities and to discuss issues related to the application for new payment amounts. OPG is seeking a rate of return consistent with the scope and type of business risks associated with reliably operating, maintaining and developing its regulated assets. Further information about OPG's application filed with the OEB is included under the heading *Recent Developments, Decisions by the Ontario Energy Board*.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station, stations whose generation output is subject to a Hydroelectric Energy Supply Agreement ("HESA") with the Ontario Power Authority ("OPA") pursuant to a ministerial directive, and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets are also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options expired on April 30, 2006, volumes sold under such options were excluded from the revenue limit rebate.

The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and will increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the OPA are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's audited consolidated operating results. A detailed discussion of OPG's performance by reportable business segment is included under the heading, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2007**	**2006**
Revenue		
Revenue before revenue limit rebate	**5,887**	5,725
Revenue limit rebate	**(227)**	(161)
	5,660	5,564
Earnings		
Income before the following:	**610**	791
Other (gains) and losses	**(10)**	22
Income before interest and income taxes	**620**	769
Net interest expense	**143**	193
Income before income taxes	**477**	576
Income tax (recoveries) expenses	**(51)**	86
Net income	**528**	490
Electricity production (TWh)	**105.1**	105.2
Cash flow		
Cash flow provided by operating activities	**407**	397

Net income for the year ended December 31, 2007 was $528 million compared to $490 million in 2006, an increase of $38 million. Income before income taxes for the year ended December 31, 2007 was $477 million compared to $576 million in 2006, a decrease of $99 million.

For the year ended December 31, 2007, there was a net income tax recovery of $51 million, compared to an income tax expense of $86 million for 2006. The decrease in income tax expense was largely due to an additional contribution to the Used Fuel Segregated Fund ("Used Fuel Fund") of $334 million in 2007. These contributions are deductible for tax purposes. There is no offsetting future tax expense due to the use of the taxes payable method to account for income taxes for the rate regulated segment. In addition, the income tax expense was favourably impacted by a reduction in federal future income tax rates that were substantively enacted in 2007.

The following is a summary of the factors impacting OPG's results for the year ended December 31, 2007 compared to results in 2006, on a before-tax basis:

(millions of dollars – before tax)	
Income before income taxes for the year ended December 31, 2006	**576**
Changes in gross margin	
Increase in electricity sales price after revenue limit rebate and hedging margin	20
Change in electricity generation by segment:	
Regulated – Nuclear	(127)
Regulated – Hydroelectric	(5)
Unregulated – Hydroelectric	(47)
Unregulated – Fossil-Fuelled	61
Increase in fuel expense primarily due to higher costs for coal consumed in production and higher uranium prices	(27)
Increase in ancillary revenue	13
Increase in non-electricity generation revenue primarily due to an increase in nuclear technical services revenue	67
Decrease in trading revenue primarily due to lower mark-to-market gains and lower transaction margins	(45)
Other changes in gross margin	14
	(76)
Increase in operations and maintenance expenses primarily due to higher outage expenditures at OPG's nuclear stations and an increase in maintenance at the fossil-fuelled generating stations	(95)
Increase in costs to support nuclear technical services provided to external parties	(30)
Additional costs included in operations, maintenance and administration expenses related to past grievances by First Nations	(30)
Increase in pension and other post employment benefit costs	(14)
Increase in earnings on nuclear fixed asset removal and nuclear waste management funds	110
Decrease in depreciation expense primarily due to the extension of service lives of the coal-fired generating stations in 2006	65
Decrease in net interest expense primarily due to deferral of interest related to the Pickering A return to service deferral account	50
Increase in amortization of the Pickering A return to service deferral account balance	(71)
Other changes	(40)
Decrease in income before other gains and losses and income taxes	(131)
Impairment of long-lived assets recognized in 2006	22
Other gains and losses recognized in 2007	10
Income before income taxes for the year ended December 31, 2007	**477**

Earnings for the year ended December 31, 2007 were unfavourably impacted by a decrease in gross margin from electricity sales compared to 2006 primarily due to lower generation from OPG's nuclear and unregulated hydroelectric generating stations, partly offset by an increase in generation from higher marginal cost fossil-fuelled generating stations. The gross margin from electricity sales was further reduced by higher costs for coal and uranium consumed in production in 2007 compared to 2006.

Gross margin was favourably impacted by an increase in ancillary revenue due to higher revenue recognized related to the Lennox reliability must run ("RMR") contract. The RMR contract is a cost-based contract with the IESO that provides regular payments, which are subject to adjustments for actual costs. The contract was contingent upon approval by the OEB. The increase in revenue recognized in 2007 was partly due to the timing in which OEB approval was issued for the current and prior year contracts.

Gross margin was also impacted by an increase in non-electricity revenue primarily due to an increase in nuclear technical services provided to external parties. Trading revenue decreased in 2007 compared to 2006 primarily due to lower mark-to-market gains and lower margins on trading transactions.

For the year ended December 31, 2007, operations, maintenance and administration ("OM&A") expenses were $2,974 million compared to $2,752 million in 2006. The increase was primarily due to higher outage expenditures at OPG's nuclear generating stations, increased maintenance programs and projects related to the extended period over which the coal-fired generating stations will be required to operate, and additional expenses related to past grievances by First Nations. OPG also incurred additional expenses during 2007 due to the increase in nuclear technical services provided to external parties.

Earnings from the Used Fuel Fund and the Decommissioning Segregated Fund ("Decommissioning Fund") (together, the "Nuclear Funds"), in 2007 were $481 million compared to $371 million in 2006, an increase of $110 million. The increase in earnings from the Nuclear Funds was due to a higher asset base in 2007, a higher Ontario Consumer Price Index ("CPI") in 2007 compared to 2006, which impacted the guaranteed return on the Used Fuel Fund, and the reimbursement from the Decommissioning Fund for expenditures related to the safe storage of Pickering A Units 2 and 3. The increase in earnings from the Nuclear Funds as a result of these factors, was partially offset by a lower rate of return in the Decommissioning Fund in 2007 of 5.15 per cent compared to 5.75 per cent in 2006 as a result of changes in the ONFA Reference Plan, approved in December 2006.

The demolition of the former Lakeview coal-fired generating station was substantially completed during 2007. During the fourth quarter of 2007, the Company re-estimated the costs to complete the remaining work to remediate the site in 2008. As a result, OPG recorded a recovery of $20 million in other gains and losses to reflect a change in the estimated costs.

During the fourth quarter of 2007, OPG recorded impairment losses of $10 million in other gains and losses related to the fair market value of its third-party Asset-Backed Commercial Paper ("ABCP") holdings.

For the year ended December 31, 2006, OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result of changes in circumstance, which included a decrease in forecasted Ontario electricity spot market prices and the extension of the lives of the coal-fired stations. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives. The impairment charge was recorded in other gains and losses.

Net interest expense for the year ended December 31, 2007 was $143 million compared to $193 million for 2006, a decrease of $50 million. The decrease in net interest expense in 2007 was primarily due to the deferral of interest expense related to the Pickering A return to service deferral account as required by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

The amortization of the Pickering A return to service deferral account increased by $71 million during 2007, compared to the same period in 2006, consistent with the method of recovery of costs included in regulated prices.

Following the introduction of rate regulation on April 1, 2005, OPG has accounted for income taxes related to the rate regulated segments of its business using the taxes payable method. Under this method, future income tax assets and liabilities associated with these segments are not recognized where those future income taxes are expected to be recovered or refunded through future regulated prices charged to customers. As a result, OPG did not record a future tax expense of $127 million and $89 million for the rate regulated segments during 2007 and 2006, respectively, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable business segment, net of the revenue limit rebate for the years ended December 31, 2007 and 2006 were as follows:

(¢/kWh)	**2007**	**2006**
Weighted average hourly Ontario spot electricity market price	**5.1**	4.9
Regulated – Nuclear	**4.9**	4.9
Regulated – Hydroelectric [1]	**3.5**	3.5
Unregulated – Hydroelectric [2]	**4.7**	4.6
Unregulated – Fossil-Fuelled [2]	**4.8**	4.8
OPG's average sales price	**4.6**	4.6

[1] Electricity generated from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

[2] 85 per cent of the electricity generated from unregulated stations, excluding the Lennox generating station and other contract volumes, is subject to a revenue limit. During the period from April 1, 2005 to April 30, 2006, the revenue limit was set at 4.7¢/kWh. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh and subsequently increased to 4.7¢/kWh effective May 1, 2007.

The weighted average hourly Ontario spot electricity market price was 5.1¢/kWh for the year ended December 31, 2007 compared to 4.9¢/kWh during 2006. The increase was primarily a result of lower nuclear and hydroelectric generation and the impact of higher primary demand in Ontario, partially offset by a stronger Canadian dollar which contributes to lower spot market prices.

OPG's average sales price was 4.6¢/kWh during the years ended December 31, 2007 and 2006. The favourable impact on OPG's average sales price of a higher revenue limit of 4.7¢/kWh for OPG's unregulated electricity generation, which commenced May 1, 2007, was partially offset by a lower revenue limit of 4.6¢/kWh during the period of January to April, 2007. On May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh.

As a result of regulated prices and the revenue limit rebate, OPG's average sales price during 2007 and 2006 was lower than the weighted average hourly Ontario spot electricity market price.

Electricity Generation

Total electricity generated during the year ended December 31, 2007 from OPG's generating stations was 105.1 TWh compared to 105.2 TWh in 2006.

Electricity generation from OPG's nuclear stations was 44.2 TWh in 2007 compared to 46.9 TWh in 2006. The decrease of 2.7 TWh was partly due to the shutdown of Units 1 and 4 at the Pickering A nuclear generating station during the period from June to September to perform modifications on a backup electrical system. Unit 4 was restarted in October 2007. Unit 1 entered a planned outage, and was restarted in early January 2008. Nuclear generation in 2007 was also unfavourably impacted by an extension to a planned outage during the first quarter of 2007 at the Pickering A nuclear generating station for significant repair work required as a result of a component failure during inspection. In addition, nuclear generation decreased as a result of an unplanned outage during the first quarter of 2007 at the Pickering B nuclear generation station. This outage was caused by an inadvertent release of resin, by a third-party contractor, from the water treatment plant into the station's demineralized water system, and the requirement for maintenance related to the recovery of resin.

For the year ended December 31, 2007, electricity sales volume in the Regulated - Hydroelectric segment was 18.1 TWh compared to 18.3 TWh in 2006. Electricity generated by the unregulated hydroelectric facilities in 2007 was 13.8 TWh compared to 15.0 TWh in 2006, a decrease of 1.2 TWh. The decrease in electricity generated by the regulated and unregulated hydroelectric facilities in 2007 compared to 2006 was primarily a result of lower water levels in Eastern Ontario during the fourth quarter of 2007.

Electricity generation from OPG's fossil-fuelled generating stations in 2007 was 29.0 TWh compared to 25.0 TWh in 2006. The increase was primarily due to lower generation from OPG's nuclear and hydroelectric generating stations, and improved station performance.

OPG's operating results are impacted by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of Heating and Cooling Degree Days for the years ended December 31:

	2007	**2006**
Heating Degree Days [1]		
Total for year	**3,684**	3,346
Ten-year average	**3,601**	3,626
Cooling Degree Days [2]		
Total for year	**454**	391
Ten-year average	**394**	372

[1] Heating Degree Days are recorded on days with an average temperature below 18^{0}C, and represent the aggregate of the differences between the average temperature and 18^{0}C for each day during the period, as measured at Pearson International Airport in Toronto, Ontario.

[2] Cooling Degree Days are recorded on days with an average temperature above 18^{0}C, and represent the aggregate of the differences between the average temperature and 18^{0}C for each day during the period, as measured at Pearson International Airport in Toronto, Ontario.

Heating Degree Days for 2007 increased significantly compared to 2006 primarily due to weather that was colder during the first and fourth quarters of 2007 compared to the same quarters in 2006. Cooling Degree Days for 2007 increased compared to 2006 as a result of weather that was warmer than average and warmer compared to 2006. Ontario primary electricity demand was 152.2 TWh and 151.1 TWh for 2007 and 2006, respectively.

Cash Flow from Operations

Cash flow provided by operating activities for 2007 was $407 million compared to $397 million for 2006. The increase in cash flow was primarily due to lower revenue limit rebate payments, the increase in non-electricity generation revenue, and a higher reimbursement of expenditures from the Nuclear Funds associated with the safe storage of Units 2 and 3 at the Pickering A nuclear generating station. The increase in cash flow was partially offset by a one-time contribution of $334 million to the Used Fuel Fund as required by the ONFA, higher operating and maintenance expenditures, and a decrease in cash receipts from electricity sales. The lower revenue limit rebate payments for 2007 compared to 2006 were a result of making a payment of $739 million in the second quarter of 2006 related to the period from April 1, 2005, to December 31, 2005. Revenue limit rebate payments are now made on a quarterly basis.

Recent Developments

Decisions by the Ontario Energy Board

In February 2008, the OEB held a hearing to consider OPG's request that payment amounts for its regulated facilities be declared interim, effective April 1, 2008, and OPG's request for an interim increase in payment amounts. The OEB granted OPG's request that payment amounts be made interim, effective April 1, 2008. This decision preserves the opportunity for OPG to recover the difference between final payment amounts as approved by the OEB and the current payment amounts, for the period between April 1, 2008 and the date of the OEB's final order. The decision regarding retrospective recovery will be made by the OEB as part of the final payment order. The OEB did not approve an interim increase in payment amounts, and stated that if a retrospective recovery adjustment is required, it can be achieved prospectively by spreading the impact of the adjustment over a period after the final order is made. Standard & Poor's Rating Services indicated that OPG's ratings would be unaffected by the OEB's decision with respect to an interim increase in payment amounts.

Investments in Asset-Backed Commercial Paper

In August 2007, a number of Canadian third-party Trusts, as issuers of ABCP, experienced difficulty in accessing the liquidity required to repay maturing ABCP debt. OPG's original exposure to third-party ABCP notes was $103 million. Of that total, $45 million consisted of notes held with Skeena Capital Trust ("Skeena"). In December 2007, OPG received payment of approximately $44 million against these notes and recognized an impairment loss of $1 million. The settlement amount represented 98.65 per cent of the original investment including interest up to the maturity date.

Following the settlement of investments in Skeena, OPG's holdings of third-party ABCP was reduced to $58 million. On December 23, 2007, a restructuring plan was announced for the remaining third-party ABCP Trusts. Documentation of the restructuring plan for these Trusts is expected in March 2008. Approval for any restructuring is required by note holders representing not less than 66 and two-thirds of the value of the Trusts.

OPG performed a valuation analysis as at December 31, 2007 to assess the amount of any impairment, taking into account the limited information available. The assessment considered the likelihood of achieving a successful restructuring based on the current proposal announced on December 23, 2007. OPG used a probability weighted cash flow model to determine the fair value of its third-party ABCP holdings. Since the majority of OPG's remaining ABCP is made up of combined traditional and synthetic assets such as Collateralized Debt Obligations ("CDO's"), the recoverability was estimated to be 85 per cent. An insignificant amount of OPG's remaining ABCP is made up of ineligible assets, where the underlying assets or the collateral provided is supported by United States ("U.S.") sub-prime assets. The recoverability of these ineligible assets was estimated to be 70 per cent. OPG also considered alternative methods to assess the fair value of the investments. As a result of the analysis, OPG recorded an impairment loss of $9 million against the remaining holdings of $58 million, in addition to the $1 million loss related to the Skeena investments. The impairment loss is included in other gains and losses.

OPG reviewed the classification of its third-party ABCP holdings and has determined that a long-term classification is appropriate, based on the restructuring information available. OPG will continue to monitor developments with respect to ABCP and will continue to assess its position.

OPG has sufficient credit facilities to satisfy its financial obligations as they come due and does not expect any material adverse impact on its operations as a result of this current third-party ABCP liquidity issue.

Climate Change Plan

In June 2007, aggressive targets to reduce greenhouse gas emissions were introduced by the Province as part of the Province's climate change plan. Among other initiatives, the plan identified a target reduction of greenhouse gases to six per cent below 1990 levels by 2014. In August 2007, the Province finalized a regulation that commits to end the use of coal to generate electricity at OPG's coal-fired generating stations by December 31, 2014.

The Federal Government, in April 2007, also announced targets for reducing both greenhouse gases and air pollutants from 2006 levels. Under the Federal proposal, OPG would be required to reduce its intensity levels of greenhouse gas emissions from its fossil-fuelled generating stations from 2006 levels by 18 per cent in 2010, with an eventual reduction of 28 per cent by 2015. The Federal Government has delayed the regulation of air pollutants until the spring of 2008, and expects to have the greenhouse gas framework finalized by the end of 2008.

Lennox Generating Station

The Lennox generating station operated under an RMR contract approved by the OEB for the period beginning on October 1, 2006 to September 30, 2007. The IESO has concluded that all four units at the Lennox generating station continue to be required for the purpose of reliability, and recommended that all four units be covered by an RMR contract for the period from October 1, 2007 to September 30, 2008. An RMR contract with the IESO for the period from October 1, 2007 to September 30, 2008 was approved by the OEB in December 2007.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to cost effectively produce electricity from its diversified generating assets, while operating in a safe, open and environmentally responsible manner. To achieve its mandate, OPG is focused on four corporate strategies: improving the performance of its generating assets; increasing its generating capacity; achieving financial sustainability; and achieving excellence in corporate governance, safety, social responsibility, corporate citizenship and environmental stewardship.

Improving the Performance of Generating Assets

Nuclear Generating Assets

OPG's strategic objective with respect to its nuclear generating assets is to operate the Darlington, and Pickering A and B nuclear generating stations in a safe, efficient and cost effective manner, while undertaking prudent investments to improve their reliability and operating performance. To achieve this objective, programs and initiatives have been implemented that will continue to: improve safety performance; reduce generation interruptions through improvements in equipment reliability; increase generation through improved planning and execution of maintenance outages; mitigate technological risks through comprehensive inspection and testing programs; and address longer term human resource and demographic issues. These initiatives, combined with ongoing cost control efforts, are expected to result in lower production unit energy costs.

Nuclear safety is a major driver of maintenance expenditures. Nuclear inspection and testing programs are largely driven by maintenance governance requirements designed to ensure that equipment is fit for service and performs as expected. This enables OPG to satisfy regulatory requirements that the stations are safe to operate, and that nuclear safety is not compromised.

OPG is transitioning from maintenance programs designed to improve the condition of equipment to initiatives aimed at increasing the reliability of generation and the predictability of performance. OPG plans to perform major scheduled maintenance over the next three years, including vacuum building outages at both the Darlington and Pickering stations. In addition, ongoing maintenance work including inspection and cleaning of steam generators, and the servicing of pumps, valves and other equipment or components will continue in accordance with life cycle maintenance work plans.

OPG is focused on reducing maintenance backlogs to improve equipment reliability. The initiative to reduce corrective maintenance backlogs to industry levels was successful in 2007. In addition, by year end, the Darlington and Pickering A stations had achieved significant reductions in elective maintenance backlogs compared to 2006.

OPG is focused on reducing the number and length of planned outages to increase generation time. The planned outage schedule at the Darlington station has moved to a three-year cycle from a two-year cycle. The Pickering stations remain on a two-year planned outage schedule. The reduction in outage duration targeted at the nuclear stations reflects ongoing and new programs aimed at improving the planning, execution, monitoring and reporting of outage work.

In 2007, OPG also implemented hiring and training programs to improve employee performance and promote leadership development, while addressing demographic and developmental issues.

Pickering A Units 2 and 3 Safe Storage Project

As a result of OPG's decision in 2005 that the return to service of Units 2 and 3 at the Pickering A nuclear station could not be justified on a commercial basis, an initiative is underway to place these units in a safe state for the remaining life of the station and an additional 30-year period prior to dismantlement. The project includes isolating Units 2 and 3 from the rest of the generating station, redesigning the control room for the remaining two operating units, and de-watering and de-fuelling the units.

The initial cost estimate of the project was approximately $270 million, with completion targeted for 2009. In the third quarter of 2007, the Canadian Nuclear Safety Commission ("CNSC") concluded that an Environmental Assessment ("EA") was necessary for certain parts of the Units 2 and 3 safe storage project. As a result, certain planned work has been suspended pending completion of the EA. It is estimated that as a result of the EA requirement, completion of the safe storage project will be delayed by approximately 14 months. The total project cost will be increased by approximately $40 million, including costs for the continued monitoring of the units in their current state.

Refurbishment Projects

Work is proceeding on the feasibility study to refurbish the Pickering B nuclear generating station. This work includes an assessment of the plant condition, an EA, and an Integrated Safety Review. Work to complete the EA and Integrated Safety Review is continuing and has extended the time frame required to define the scope of the refurbishment project and complete a comprehensive assessment. As a result, OPG plans to make a recommendation regarding the feasibility of this project to its Board of Directors in early 2009.

OPG plans to begin a feasibility study on the refurbishment of the Darlington nuclear generating station commencing in 2008.

Hydroelectric Generating Assets

OPG's strategic objective with respect to its existing hydroelectric generating assets is to improve 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 53 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 generating assets achieved an availability of 94 per cent in 2007, which is the best performance in 23 years. OPG plans to maintain high reliability levels as measured by availability factors in excess of 90 per cent and an equivalent forced outage rate of less than 2 per cent.

The hydroelectric business segment is strengthening its relationships with First Nations and local communities. In 2007, a number of ceremonies recognizing the settlement of past grievances were held with First Nations.

OPG is meeting the demographic challenges faced by its hydroelectric business unit by training staff to perform new roles and by hiring new staff. OPG mentors these new employees in safe work practices and technical skills to ensure continuing performance improvements.

Fossil-Fuelled Generating Assets

OPG's strategic objective with respect to its fossil-fuelled generating assets is to maintain the productive capability of its coal-fired generating facilities for as long as they are required, while continuing to operate in compliance with all applicable environmental laws and emission regulations. OPG's fossil-fuelled generating stations perform as intermediate and peaking facilities, which results in many frequent starts and stops of the units. Maintenance programs have been implemented to mitigate the unfavourable impacts of these starts and stops on equipment.

The reliability of OPG's fossil-fuelled stations has continued to improve. During 2007, the reliability of OPG's fossil-fuelled generating assets as measured by equivalent forced outage rates, was the best since 2000. This level of reliability is expected to be maintained over the next few years. Improved reliability in 2007 also resulted in less corrective maintenance work, which had a positive impact on maintenance expenses.

OPG's Unregulated – Fossil-Fuelled business segment has more than 1,500 employees. During the past two years, approximately 20 per cent of employees have been replaced in order to manage the effects of an aging workforce. The majority of the new hires were external recruits. OPG provides in-house technical training to assist staff with their new roles, and to adopt safe work practices.

A focus on maintenance, environmental and recruitment programs will enable the continued operation of the coal-fired generating stations for as long as they are required.

Increasing OPG's Generating Capacity

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generating capacity by expanding and redeveloping its existing sites, as well as pursuing new projects where feasible. In addition, OPG, in consultation with its shareholder, plans to explore and develop, where feasible, natural gas and nuclear opportunities in Ontario. OPG will undertake these investments on its own or through partnerships. OPG is currently involved in the following hydroelectric, natural gas and nuclear generation projects.

Niagara Tunnel

The Niagara tunnel project will increase the amount of water flowing to existing turbines at OPG's Sir Adam Beck generating stations in Niagara Falls, allowing the stations to more effectively utilize available water. Upon the completion of the 10.4 km tunnel, the average annual generation from the Sir Adam Beck generating stations is expected to increase by approximately 1.6 TWh.

At December 31, 2007, the tunnel boring machine had advanced 1,609 metres. The progress of the tunnel boring machine by the design-build contractor through a fractured rock formation has been slower than expected. Considerable uncertainty remains with respect to the schedule until the tunnel boring machine advances sufficiently beyond the St. David's gorge to approximately 2,300 metres, and establishes consistent tunneling performance.

The contract structure places the onus on the contractor to mitigate schedule delays, and includes liquidated damages provisions for failure to meet the contractual in-service date.

Based on the information provided by the contractor, the in-service date of the tunnel will be delayed. To mitigate the impact of the schedule delay, the contractor is investigating alternatives, including the realignment of the tunnel. The estimated in-service date will be dependent on the alternative selected by the contractor. Considerable uncertainty remains with respect to the schedule for any of the contractor's alternatives until the tunnel boring machine has advanced beyond the St. David's gorge.

There is a potential that the schedule delay could impact the project cost. The project cost estimate of $985 million will be reviewed in conjunction with any changes to the project completion schedule and a review of actual subsurface rock conditions compared to those that were anticipated as part of the design-build contract.

The capital project expenditures for 2007 were $60 million and life-to-date capital expenditures were $303 million. The project is debt financed through the Ontario Electricity Financial Corporation ("OEFC").

Lac Seul

OPG is constructing a new 12.5 MW hydroelectric generating station on the English River. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded and construction started during the first quarter of 2006. In accordance with the contractor's original schedule, the project was expected to be in-service in the fourth quarter of 2007. However, the contractor has advised OPG that the project is now expected to be in-service in the third quarter of 2008. The program delays are a result of various difficulties, including the replacement of the major subcontractor on two occasions.

The design-build contract includes liquidated damages terms to mitigate, among other things, the impact of any project delay. OPG is deducting applicable liquidated damages from amounts otherwise payable to the contractor for the late in-service date.

At year end 2007, the powerhouse was substantially complete. Turbine/generator components have been installed and unit alignment has begun. Auxiliary systems, station service, heating and lighting are substantially complete. Concrete work at the intake area is continuing. Life-to-date expenditures are $41 million. Total project costs are expected to be $47 million. The project is financed through the OEFC.

Lower Mattagami

In May 2006, OPG provided development alternatives to the Province to increase the generating capacity of four hydroelectric generating stations on the Lower Mattagami River. The incremental capacity associated with these alternatives ranged from approximately 140 MW to 450 MW. The Minister of Energy subsequently directed OPG to proceed with the definition phase for a 450 MW development which includes the replacement of the Smoky Falls generating station and the expansion of the Little Long, Harmon and Kipling generating stations, all of which are located on the Lower Mattagami River.

Following discussions with the Canadian Environmental Assessment Agency ("CEAA"), it was determined that a comprehensive study process must be followed under CEAA regulations. A scoping document for this process has been posted on the CEAA website for public comment.

OPG is engaged in consultations with First Nations stakeholders regarding an agreement to address past issues and establish a new commercial relationship.

Small Hydroelectric Projects

In December 2007, OPG's Board of Directors approved the redevelopment of four existing hydroelectric generation stations that are at the end of their useful lives and would otherwise be removed from service in the near future. Three of the generating stations are on the Upper Mattagami River (Wawaitin, Sandy Falls and Lower Sturgeon) and the fourth (Hound Chute) is located on the Montreal River. Due to their similar size and geographic proximity, the redevelopments are being combined as one project under one design-build contract. Upon completion of the project, the total installed capacity of the four stations will increase from 23 MW to 44 MW, and the annual energy will increase from 134 gigawatt hours ("GWh") to 223 GWh. The total approved project cost is approximately $300 million with project completion planned for the second quarter of 2011. The project is expected to be financed through third-party project financing.

In December 2007, OPG commenced a 6.4 MW expansion of the existing Healey Falls generating station on the Trent-Severn Waterway that will result in additional energy production of 25 GWh per year. The total approved project cost is $22 million with project completion planned for mid-2010.

Hydroelectric Projects Directive

In December 20, 2007, the Minister of Energy issued a directive to the OPA to negotiate HESA with OPG for the following hydroelectric development projects: Lac Seul, Upper Mattagami, Hound Chute, Healey Falls, and Lower Mattagami. The final review of the Lac Seul HESA was completed in January 2008 and the agreement was executed. The directive indicated that the negotiation and execution of the remaining agreements should be completed in the first half of 2008.

Portlands Energy Centre

OPG entered into a partnership with TransCanada Energy Ltd., through the Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle generating station on the site of the former R.L. Hearn generating station, near downtown Toronto. OPG has a 50 per cent ownership interest in the joint venture.

Construction of the generating station started in 2006 and it is expected to be operational in a simple cycle mode with a capacity of up to 340 MW by June 1, 2008. The simple cycle mode will only operate as needed during the summer of 2008, after which the generating station will be taken out of service to enable construction to be completed on the combined cycle mode. During 2007, construction progress included substantial work on the pumphouse, assembly of generator step-up transformers, erection of gas compressor building steel, and completion of the steam turbine generator pedestal.

The plant is expected to be completed and fully operational in the second quarter of 2009, providing up to 550 MW of power in a combined cycle mode. Project costs are expected to be within the approved budget, which is $730 million excluding capitalized interest. A significant proportion of this capital cost relates to an engineer-procure-construct contract to construct the facility.

OPG's share of capital expenditures for 2007 was $176 million. OPG's share of the life-to-date capital expenditures was $273 million. OPG's share of the project is debt financed through the OEFC.

Lakeview Site

OPG is continuing with the decommissioning and demolition of the Lakeview coal-fired generating station, having closed the station in 2005 after more than 40 years of service. OPG is exploring the potential development of a gas-fuelled electricity generating station at the site. Construction of a new plant would proceed only after the required approvals and the completion of a clean energy supply agreement.

New Nuclear Generating Units

As directed by the Minister of Energy in June 2006, OPG initiated a federal approvals process in September 2006 by filing an Application for a Site Preparation Licence with the CNSC for new nuclear generating units at the Darlington nuclear generating site.

During the first quarter of 2007, OPG proceeded with initiatives in support of an EA for new nuclear units at the Darlington site that included studies relating to geology, distribution and movements of groundwater and aquifers, archeology and terrestrial. During the second quarter of 2007, OPG continued to the second step in the federal approvals process by filing a Project Description to be used by the CNSC to determine the type of EA that is required.

In January 2008, the CNSC recommended to the Federal Minister of Environment that the project be referred to a panel review, which is the highest level of review under current legislation. The Minister's decision on the recommendation is pending. Planning for new nuclear generating units at OPG's Darlington nuclear generating site continues.

OPG and Bruce Power jointly undertook to assess the potential nuclear technologies, which might be deployed in Ontario. Technologies under review include existing, evolutionary and new designs. This assessment will provide the Province with a generator's perspective to be considered in its global examination of nuclear reactor technologies.

Achieving Financial Sustainability

With respect to its strategic financial objectives, OPG's mandate, as agreed with its Shareholder, states that: as an Ontario Business Corporations Act 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. In addition, as a transition to a sustainable financial model, any significant new generation project approved by OPG's Board of Directors and agreed to or directed by the Shareholder, may receive financial support from the Province, if and as appropriate.

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 equitable treatment for production from unregulated assets; identifying and exploiting efficiency improvement opportunities; and ensuring that sufficient funds are available to achieve OPG's strategic objectives of improving the performance of its generating assets and increasing its generating capacity. OPG has employed a number of strategies to achieve a level of sustainable financial performance.

OPG's ability to increase its revenues is constrained as it receives regulated prices for electricity produced from its nuclear generating stations and most of its baseload hydroelectric generating stations. To address this constraint, OPG filed an application with the OEB in November 2007, for new payment amounts for its regulated facilities effective April 1, 2008, for a 21-month period. OPG will seek a rate of return consistent with the scope and type of business risks associated with reliably operating and responsibly increasing production from its regulated assets. OPG revenues are also constrained by a revenue limit on the majority of the output from its other generating assets. This limit was established in April 2006, and will cease on April 30, 2009.

OPG is focused on implementing effective cost management initiatives to identify and exploit opportunities to improve efficiency. In 2007, OPG undertook a review of its support function activities to further optimize the management of available resources.

To the extent that additional funds, beyond those generated from operations, are required, OPG seeks agreement with its Shareholder on options to ensure that adequate financing resources are available to fund ongoing operational requirements and new generation development. OPG will continue to seek opportunities to diversify its sources of funding and increase its access to cost effective capital. By ensuring access to cost effective funding and maintaining its investment grade credit ratings, OPG will ensure its status as a long-term, commercially viable investment.

Excellence in Corporate Governance, Safety, Social Responsibility, Corporate Citizenship and Environmental Stewardship

Another of OPG's strategic objectives is to operate in accordance with the highest corporate standards, including, but not limited to, the areas of corporate governance, safety, and sustainable development.

Corporate Governance

OPG's corporate governance strategy is to continually improve the policies and procedures used to direct and manage the corporation. OPG continues to implement initiatives that are consistent with Ontario Securities Commission ("OSC") regulatory requirements in order to enhance its corporate governance practices. A description of OPG's corporate governance structure is described in the *Corporate Governance* section.

OPG's Board of Directors consists of a majority of independent directors with substantial capability in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board has established a number of committees to focus on areas critical to the success of the Company. The Board develops governance principles for OPG that are consistent with high standards of corporate governance and annually reviews OPG's system of corporate governance with a view to maintaining these standards.

Safety

OPG is committed to achieving excellence in employee 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. Continuous oversight and reporting provides management with information on the effectiveness of safety management initiatives, compliance with legal and corporate requirements, and safety performance trends. Oversight activities include internal and external safety management system audits, work protection code audits, and specific operational safety risk reviews. OPG also has a rigorous incident management system, which requires that all incidents including near misses be reported and investigated, as appropriate, and that corrective action plans are developed to prevent reoccurrences.

OPG's safety culture is rooted in the belief that zero injuries can be a reality. This culture is supported through initiatives that address safety issues related to young and new employees. Also, a contractor management program ensures that contractors contribute to OPG's strong safety culture, and that they maintain a level of safety equivalent to that of employees.

OPG measures its safety performance primarily through two performance indicators – Accident Severity Rate ("ASR") and All Injury Rate ("AIR"). The ASR is a measure of the number of days lost due to injuries. In 2007, OPG experienced 1.56 days lost per 200,000 hours worked compared to 5.87 in 2006. The AIR provides a measure of the frequency of injuries resulting in lost time or requiring medical treatment. In 2007, OPG experienced 1.12 injuries per 200,000 hours worked compared to 1.30 in 2006. OPG's 2007 ASR and AIR improved significantly compared to 2006 and is the best performance that the Company has achieved since its inception in 1999. This improvement can be attributed to visible leadership and commitment to safety, a strong safety culture where employees take personal responsibility for safety, effective safety management systems with targeted risk mitigation strategies, and robust return to work strategies for injured workers.

Safety performance at OPG's nuclear generating stations improved in 2007. The Pickering A station completed two million hours of work without a loss time accident, and the Pickering B and Darlington stations completed over three million hours of work without a loss time accident.

In 2007, the hydroelectric business segment achieved two years without a lost time accident. Certain hydroelectric plant groups have achieved significant safety milestones, including some that have worked more than 10 years without a lost time accident.

The fossil-fuelled business unit experienced exceptional safety performance in 2007. Certain stations achieved significant safety milestones, including the Thunder Bay generating station that has worked 10 years without a lost time accident, and the Lennox generating station that has worked five years without a lost time accident.

A commitment to public safety is also an important part of the operation of OPG's generating stations. OPG works to increase public awareness that dams, hydroelectric generating stations and surrounding waterways are unsafe places for recreation. An independent review of the Company's public safety systems was conducted by a panel of international experts who concluded that OPG's practices relative to other jurisdictions are a leading example for other hydroelectric organizations and dam owners.

Sustainable Development

OPG is committed to continuous improvement in its sustainable development performance, including both environmental stewardship and social responsibility. This commitment is supported by the Provincial Government's Memorandum of Agreement with OPG, which mandates OPG to operate in accordance with the highest corporate standards of environmental stewardship as well as social responsibility and corporate citizenship.

Environmental Stewardship

OPG's Environmental Policy states that "OPG will strive to continually improve its environmental performance". This policy further 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.

To achieve the goal of continuous improvement in environmental performance, each year OPG sets key performance targets, which are tracked and managed through the ISO 14001 (2004) Environmental Management System. These efforts are reinforced by an annual incentive plan that links management's compensation to meeting or surpassing internally established environmental targets. Targets are established for a wide spectrum of environmental indicators, including spills; air emissions inclusive of Nitrogen Oxides ("NO_x") and Sulphur Dioxide ("SO_2") emissions; regulatory infractions; energy efficiency improvements; and reductions in waste generated.

To achieve further improvements in OPG's greenhouse gas emissions, OPG launched its Greenhouse Gas Management Plan in 2007. The plan focuses on: improving the energy efficiency of OPG's facilities, the use of biofuels as a partial replacement for coal, researching the impact of climate change on OPG's operations, expanding the tree planting effort through OPG's extensive biodiversity program, and an education program for employees.

OPG manages air emissions of NO_x and SO_2 through the installation of specialized equipment such as scrubbers, low NO_x burners, and selective catalytic reduction equipment. OPG also purchases low sulphur fuel and utilizes a regulatory approved emissions trading program to manage emission levels within regulatory limits. The Province has directed the OPA to develop a plan to phase out coal-fired generation in the earliest possible timeframe, with the assurance that there is an adequate supply of electricity during the phase-out period. In order to ensure that coal-fired facilities are available to generate electricity within environmental regulatory requirements, OPG continues to implement emissions control strategies, including improvements to equipment. OPG will operate its coal-fired generating stations in accordance with all regulatory requirements and will implement continuous improvement measures that are consistent with the remaining in-service requirements for these stations.

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. The public also receives ongoing communications regarding OPG's environmental performance. OPG has developed and implemented internal monitoring, assessment, and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, the treatment of radioactive emissions, and radioactive wastes. OPG also continues to address historical land contamination through its voluntary land assessment and remediation program.

OPG's environmental performance for 2007 met, or was better than target, regarding major spills (Category A), major infractions, and tritium and C-14 emissions. OPG also maintained its ISO 14001 certification for its corporate level EMS and all of its generating stations. OPG did not meet its target for intermediate spills (Level B), and the NO_x emission rate for Lennox GS (oil and gas) was slightly in excess of target. Acid gas (SO_2 and NO_x) emissions were 139.5 gigagrams (Gg) in 2007 compared to 118.1 Gg in 2006. The increase in emissions was primarily a result of increased generation from the fossil facilities.

OPG began a program to test the burning of biomass fuel on selected units at its fossil-fuelled generating stations. The Atikokan generating station was also used by Ontario's Bio-Energy Research Centre to conduct and assess bio-energy initiatives.

Social Responsibility and Corporate Citizenship

Contributing to the quality of life in communities where companies operate is a corporate responsibility as well as a societal expectation. OPG is committed to being a good corporate citizen by strengthening relationships with the communities that host OPG's generating facilities. At the corporate level, as well as through the actions of employees, OPG plays a significant role in local communities by donating time and resources. OPG's Corporate Citizenship Program provides financial and in-kind support to registered charities and not-for-profit environmental, educational and community organizations whose initiatives both reflect OPG's values and help build better communities. OPG employees also strive through multiple Corporate and personal initiatives to help make local communities better places to live.

OPG is committed to openness and transparency in its reporting to the broader community. This includes distributing operational and financial reports that are prepared in a manner that users can easily understand, as well as making these reports available on our website, opg.com.

CAPABILITY TO DELIVER RESULTS

Generating Assets

OPG continues to implement specific initiatives to improve the reliability and predictability of each nuclear generating station. These initiatives are designed to address the specific technology requirements, operational experience, and mitigate risks. The Darlington nuclear generating station is transitioning to a three-year outage cycle to take advantage of the physical condition of the plant, the availability of backup systems, and the ability to refuel during operations. The Pickering B nuclear generating station will continue to focus on making targeted improvements in reliability.

OPG has increased the productive capacity of its hydroelectric stations, extended their service lives and invested significant capital to replace aging equipment, upgrade runners, increase station automation, and enhance maintenance practices. Programs are in place to further improve the efficiency and availability of existing hydroelectric stations.

OPG will continue to maintain the reliability and productive capacity of its coal-fired generating stations until their scheduled closure dates.

OPG has a number of potential sites for new generating asset development in Ontario. The completion of the decommissioning activity at OPG's Lakeview generating station will provide a brownfield site with the potential for development of additional generating capacity in the Greater Toronto Area.

In addition to the discussion in this section, OPG's capability to deliver results is affected by factors discussed in the *Risk Management* section.

Skilled Workforce

As of December 31, 2007, OPG had approximately 11,700 regular employees. OPG's employees have considerable technical experience in operating and maintaining the Company's generating stations. Due to an aging workforce, OPG's challenge is to attract and retain a skilled workforce to replace retiring employees. Approximately 36 per cent of OPG's workforce was over the age of 50 at December 31, 2007. OPG has initiated a comprehensive resource and succession planning program to address demographic issues related to a high percentage of employees that are eligible for retirement over the next five years and staffing issues associated with the closure of the coal-fired generating stations.

The Company's collective agreement with the Power Workers' Union runs through March 31, 2009 and the labour agreement with The Society of Energy Professionals runs through December 31, 2010. As of December 31, 2007, the Company had approximately 90 per cent of its regular labour force represented by collective bargaining agreements.

ONTARIO ELECTRICITY MARKET TRENDS

In its 18-Month Outlook published in December 2007, the IESO indicated that Ontario's installed electricity generating capacity was 31,214 MW. OPG's in-service electricity generating capacity at the end of 2007 was 22,158 MW or 71 per cent of Ontario's capacity. The expected peak electricity demand in the summer of 2008, under normal weather conditions and prior to the impacts of targeted conservation, is forecast by the IESO to be 25,929 MW. The IESO expects energy demand in 2008 to grow by 1.1 per cent over the 2007 energy demand to 153.6 TWh. The Outlook report attributes this growth to the impact of economic and demographic growth offset by planned conservation measures. The IESO reported that over the next 18 months, the outlook for Ontario's supply/demand balance remains generally positive under a normal weather scenario. Over the next 18 months, more than 4,600 MW of new supply is scheduled to come into service. The new supply during this period includes 3,000 MW of gas-fired generation, 800 MW of nuclear generation, 100 MW of hydroelectric generation and approximately 700 MW of wind generation. This represents the highest amount of additional capacity in an 18-Month Outlook period since the Ontario electricity market began.

In the Ontario Reliability Outlook published in December 2007, the IESO identified the industry's need to shift the focus to ensuring that the new supply is implemented in time to meet Ontario's needs, as well as addressing the integration and operational challenges of a complex and changing generation mix.

The Ontario spot electricity market price is influenced by changes the United States dollar ("USD") to Canadian dollar exchange rate. Fuel prices are also affected by the USD to Canadian dollar exchange rate and the underlying commodity price. Both the spot electricity market price and fuel prices can have a significant impact on OPG's revenue and gross margin. Uranium spot market prices have increased significantly since 2003. The increase in the price of uranium is driven by a number of factors that are expected to persist, supporting higher prices for a number of years. Any significant impact on OPG's fuel costs has been mitigated by the drawing down of inventories purchased at lower prices. However, fuel costs for nuclear operations are expected to be significantly higher in the near future. During the fourth quarter of 2007, market prices for natural gas increased by approximately five per cent and coal prices increased over 10 per cent compared to market prices in the same period of 2006. The outlook for gas prices remains volatile, although the longer term trend is stabilizing in the futures markets. Coal futures have increased recently as a result of tight global markets and may remain high until various supply constraints and demand pressures are overcome. With the Federal Government's proposed EcoAction regulations, emission credit costs associated with the use of fossil fuels in the electricity sector could increase after 2009.

In August 2007, the OPA filed its proposed 20-year plan for Ontario, the Integrated Power System Plan ("IPSP"), with the OEB for approval. The OPA is required by regulation to develop and submit an IPSP that covers a period of 20 years from the date of its submission and to develop and submit an updated 20-year plan every three years thereafter. The OEB will review the IPSP and assess whether it is consistent with government directives, complies with the IPSP Regulation, and is prudent and cost effective. The plan's estimated $60 billion capital cost would be directed toward conservation initiatives, new renewable generation including hydroelectric facilities, refurbishment or replacement of nuclear generation for baseload capacity, natural gas-fired generation for intermediate and peaking uses, and the transmission capacity required to deliver the electricity to Ontario consumers. The plan also calls for the phase-out of coal-fired electricity generation by the end of 2014.

BUSINESS SEGMENTS

OPG has four reportable business segments. The business segments are Regulated – Nuclear, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Fossil-Fuelled.

OPG has entered into various energy and related sales contracts with its customers to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included in the Unregulated – Hydroelectric and Unregulated – Fossil-Fuelled generation segments. Gains or losses from these hedging transactions are recognized in revenue over the terms of the contract when the underlying transaction occurs.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This arrangement includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – Hydroelectric business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support and automatic generation control, and revenues from other services.

Other

The Other category includes revenue that OPG earns from its 50 per cent joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses. In addition, the Other category includes revenue from real estate rentals.

Key Generation and Financial Performance Indicators

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, and environmental performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology. These indicators are defined in this section and are discussed in the *Discussion of Operating Results by Business Segment* section.

Nuclear Unit Capability Factor

OPG's nuclear stations operate as baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability.

Fossil-Fuelled and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's fossil-fuelled stations provide a flexible source of energy and operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations. OPG's hydroelectric stations operate primarily as baseload facilities and provide a reliable and low-cost source of renewable energy. A key measure of the reliability of the fossil-fuelled and hydroelectric generating stations is the proportion of time they are available to produce electricity when required. EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Hydroelectric Availability

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and storage and the disposal of low and intermediate level radioactive waste materials, divided by nuclear electricity generation.

Hydroelectric OM&A Expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses, including allocated corporate costs, divided by hydroelectric electricity generation.

Fossil-Fuelled OM&A Expense per MW

Since fossil-fuelled generating stations are primarily employed during periods of intermediate and peak demand, the cost effectiveness of these stations is measured by their annualized OM&A expenses for the period, including allocated corporate costs, divided by total station nameplate capacity.

Other Key Indicators

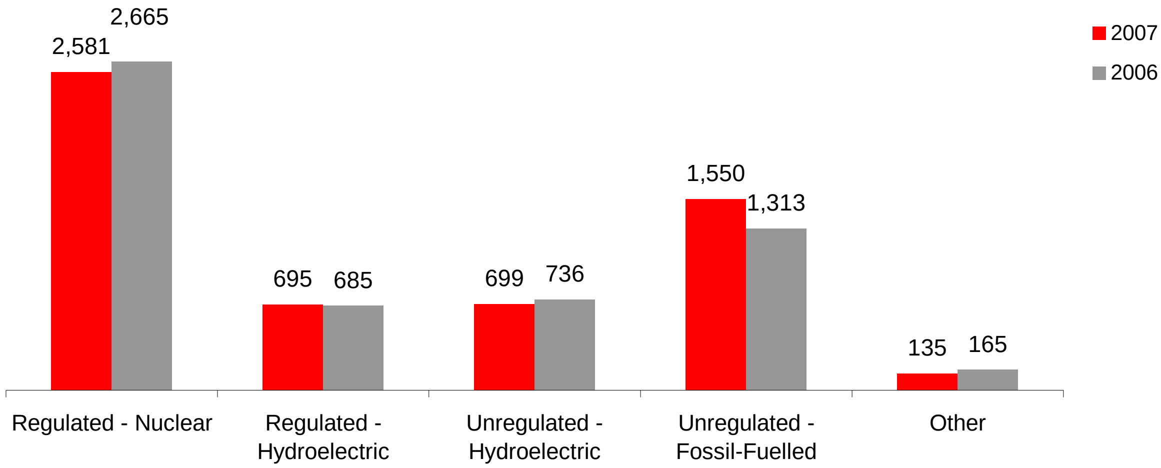
In addition to performance and cost effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, *Risk Management*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

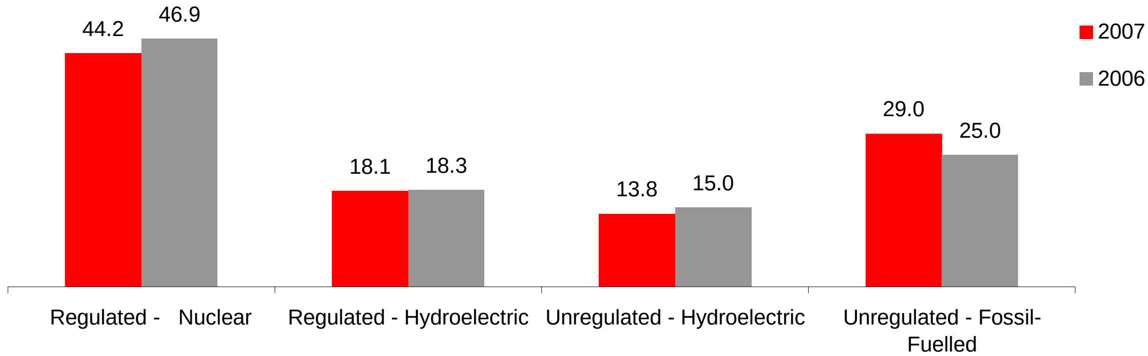
This section summarizes OPG's key results by segment for the years ended December 31, 2007 and 2006. The following table provides a summary of revenue, earnings and key generation and financial performance indicators by business segment:

(millions of dollars)	**2007**	**2006**
Revenue, net of revenue limit rebate		
Regulated – Nuclear	**2,581**	2,665
Regulated – Hydroelectric	**695**	685
Unregulated – Hydroelectric	**699**	736
Unregulated – Fossil-Fuelled	**1,550**	1,313
Other	**135**	165
	5,660	5,564
(Loss) income before interest and income taxes		
Regulated – Nuclear	**(84)**	70
Regulated – Hydroelectric	**249**	264
Unregulated – Hydroelectric	**329**	375
Unregulated – Fossil-Fuelled	**74**	(37)
Other	**52**	97
	620	769
Electricity Generation (TWh)		
Regulated – Nuclear	**44.2**	46.9
Regulated – Hydroelectric	**18.1**	18.3
Unregulated – Hydroelectric	**13.8**	15.0
Unregulated – Fossil-Fuelled	**29.0**	25.0
Total electricity generation	**105.1**	105.2
Nuclear unit capability factor (per cent)		
Darlington	**89.5**	88.7
Pickering A	**41.3**	72.0
Pickering B	**75.0**	75.2
Equivalent forced outage rate (per cent)		
Regulated – Hydroelectric	**1.8**	1.5
Unregulated – Hydroelectric	**1.5**	1.9
Unregulated – Fossil-Fuelled	**11.5**	14.1
Availability (per cent)		
Regulated – Hydroelectric	**94.1**	94.2
Unregulated – Hydroelectric	**93.9**	92.4
Nuclear PUEC ($/MWh)	**47.18**	42.87
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**5.30**	5.03
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**13.33**	11.27
Unregulated – Fossil-Fuelled OM&A expense per MW ($000/MW)	**66.8**	61.1

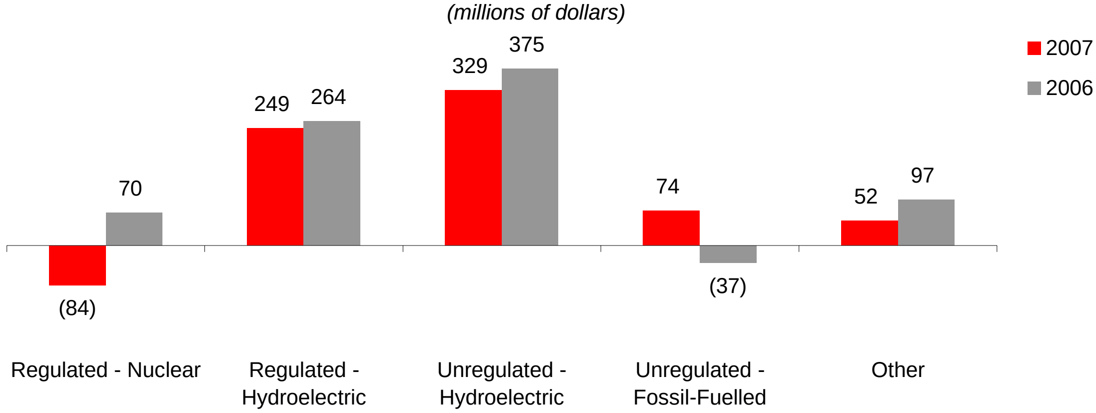
Revenue, Net of Revenue Limit Rebate by Segment
Years Ended December 31
(millions of dollars)



Electricity Generation by Segment
Years Ended December 31
(TWh)



(Loss) Income Before Interest and Income Taxes by Segment
Years Ended December 31
(millions of dollars)



Regulated – Nuclear Segment

(millions of dollars)	**2007**	**2006**
Revenue	**2,581**	2,665
Fuel expense	**133**	122
Gross margin	**2,448**	2,543
Operations, maintenance and administration	**2,061**	1,942
Depreciation and amortization	**426**	368
Accretion on fixed asset removal and nuclear waste management liabilities	**499**	490
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(481)**	(371)
Property and capital taxes	**31**	44
(Loss) income before other gains and losses, interest and income taxes	**(88)**	70
Other (gains) and losses	**(4)**	-
(Loss) income before interest and income taxes	**(84)**	70

Revenue

(millions of dollars)	**2007**	**2006**
Regulated generation sales	**2,179**	2,312
Variance account	**-**	1
Other	**402**	352
Total revenue	**2,581**	2,665

Regulated – Nuclear revenue was $2,581 million for the year ended December 31, 2007 compared to $2,665 million in 2006. The decrease in revenue was primarily due to lower electricity generation of 2.7 TWh compared to 2006, partially offset by an increase in non-electricity generation revenue from nuclear technical services provided to external parties.

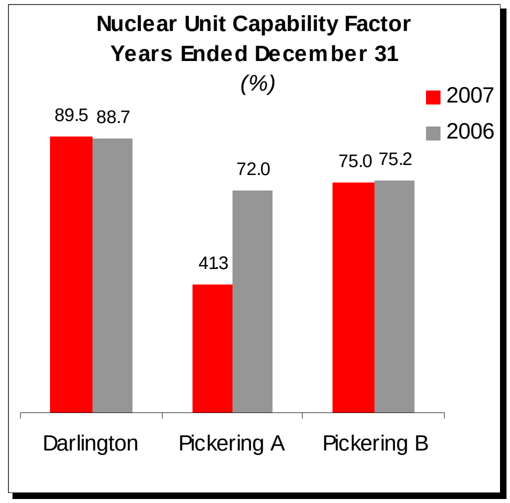
Electricity Prices

Electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh since the introduction of rate regulation effective April 1, 2005.

Volume

Electricity generation from stations in the Regulated – Nuclear segment for the year ended December 31, 2007 was 44.2 TWh compared to 46.9 TWh in 2006. The decrease in electricity generation of 2.7 TWh was partly due to the shutdown of the Pickering A nuclear generating station Units 1 and 4 in early June 2007 to perform modifications on a backup electrical system. This system provides a redundant electrical connection for the Pickering A nuclear generating station from the Pickering B nuclear generating station. A strict safety protocol dictated that Units 1 and 4 remain off-line during the completion of the modifications to the backup electrical system. This modification was completed in September 2007. Unit 4 of the Pickering A nuclear generating station was restarted in October 2007. Unit 1 entered a planned outage and was restarted in early January 2008.

Nuclear generation for 2007 was also impacted by an extension to a planned outage during the first quarter of 2007 at the Pickering A nuclear generating station for significant additional repair work required as a result of a component failure during inspection. In addition, nuclear generation decreased as a result of an unplanned outage during the first quarter of 2007 at the Pickering B nuclear generating station. This outage was caused by an inadvertent release of resin by a third-party contractor from the water treatment plant into the demineralized water system, and the requirement for maintenance related to the recovery of the resin. OPG is currently pursuing the recovery of lost revenue and incremental costs as a result of this matter. In February 2008, OPG received an interim partial payment of $10 million related to the claim.



The impact of the lower generation from the Pickering A and the Pickering B nuclear generating stations during 2007 was partially offset by continued strong performance at the Darlington nuclear generating station. For the year ended December 31, 2007, the nuclear unit capability factor for the Darlington nuclear generating station was 89.5 per cent compared to 88.7 per cent in 2006.

The nuclear unit capability factor for the Pickering A nuclear generating station was 41.3 per cent in 2007 compared to 72.0 per cent in 2006. The decrease was primarily due to significantly higher outage days due to the shutdown of Units 1 and 4 to perform modifications to the backup electrical system and as a result of the component failure during inspection during the first quarter of 2007.

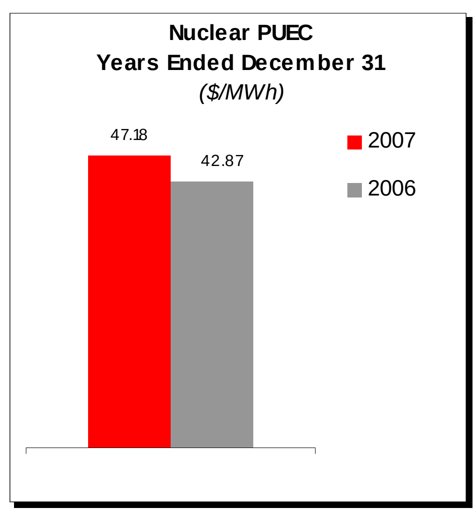
For 2007, the Pickering B nuclear generating station's nuclear unit capability factor was 75.0 per cent compared to 75.2 per cent in 2006. The decrease was primarily due to higher unplanned outage days related to the release of resin into the demineralized water system during the first quarter of 2007.

The output of Units 1 and 4 at the Pickering A nuclear generating station is currently restricted to 96 per cent of full power rating. This restriction has been imposed by the CNSC pending further review and disposition of a reactor physics assessment. The restriction on Unit 4 came into effect in October 2007 and on Unit 1 in January 2008. OPG expects the restriction will remain in force for the balance of 2008. Management has undertaken further technical evaluations and is pursing a resolution with the CNSC.

Fuel Expense

Fuel expense for the year ended December 31, 2007 was $133 million compared to $122 million in 2006. The increase in fuel expense was primarily due to higher uranium prices compared to the same period in 2006, partially offset by the impact of lower generation.

Operations, Maintenance and Administration



OM&A expenses were $2,061 million for the year ended December 31, 2007 compared to $1,942 million in 2006. The increase in OM&A expenses was primarily due to higher outage expenditures, higher costs related to the increase in nuclear technical services provided to external parties, and higher pension and OPEB costs, partially offset by reduced expenditures on nuclear project work.

Based on the amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) made in February 2007, OPG recorded a regulatory asset of $27 million related to non-capital costs for nuclear generation development initiatives during 2007.

Nuclear PUEC for the year ended December 31, 2007 was $47.18/MWh compared to $42.87/MWh during 2006. The increase was primarily due to higher maintenance and outage expenditures and lower generation volume.

Depreciation and Amortization

Depreciation and amortization expense for the year ended December 31, 2007 was $426 million compared to $368 million in 2006. The increase in depreciation and amortization expense was primarily due to the amortization of the Pickering A return to service deferral account. The amortization of the Pickering A return to service deferral account was $96 million for 2007 compared to $25 million in 2006. The amortization expense is consistent with the method of recovery of the deferred costs included in regulated prices.

At December 31, 2006, OPG increased the estimate of the present value of the asset retirement obligation for nuclear fixed asset removal and nuclear waste management by $1,386 million, based on an approved reference plan in accordance with the terms of the ONFA (the "2006 Approved Reference Plan"). Asset retirement costs are capitalized by increasing the carrying value of the related fixed assets. As a result, OPG recorded an increase in the carrying value of the nuclear fixed assets of $1,386 million at December 31, 2006. For the year ended December 31, 2007, OPG recognized additional depreciation expense of $56 million related to this increase. The increase in depreciation expense was largely offset by the impact of establishing a deferral account, effective January 1, 2007, related to the change in the liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

Accretion

Accretion expense for the year ended December 31, 2007 was $499 million compared to $490 million in 2006. The increase was due to the higher nuclear fixed asset removal and nuclear waste management liability compared to 2006 primarily as a result of the increase in the present value of the liability due to the passage of time. For the year ended December 31, 2007, OPG recorded additional accretion expense related to the increase in the estimate of the liability recorded on December 31, 2006. This increase in accretion expense was largely offset by the impact of establishing the deferral account effective January 1, 2007 relating to the change in estimate of the liabilities, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

Earnings on the Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Earnings from the Nuclear Funds for the year ended December 31, 2007 were $481 million compared to $371 million in 2006, an increase of $110 million. This increase was primarily due to a higher asset base in 2007, a higher Ontario CPI in 2007 compared to 2006, which impacted the guaranteed return on the Used Fuel Fund, and the reimbursement from the Decommissioning Fund for expenditures related to the safe storage of Pickering A Units 2 and 3 of $46 million. Under the ONFA, the Province guarantees the rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario CPI.

The increase in earnings from the Nuclear Funds was partially offset by a lower rate of return in the Decommissioning Fund in 2007 of 5.15 per cent compared to 5.75 per cent in 2006, as a result of changes in the ONFA 2006 Approved Reference Plan, approved in December 2006. Upon termination of the ONFA, the Province has a right to any funding in the Decommissioning Fund in excess of the estimated completion costs. Accordingly, the value of the investments recorded in the Decommissioning Fund is limited to the cost estimate of the related liability. When the Decommissioning Fund is overfunded, the earnings are capped at the rate of growth of the liability for the estimated completion costs under ONFA.

The assets in the Decommissioning Fund are invested primarily in publicly traded fixed income and equity investments. As a result, the value of these investments is subject to volatility in the capital markets. The volatility of the returns on these investments has increased over the past few months, which has resulted in a negative impact on the fair value and the funding status of the Decommissioning Fund. During the period January 1, 2008 to February 26, 2008, the fair value decreased by approximately 2 per cent, which resulted in a loss of approximately $100 million. The Decommissioning Fund has been designed to meet long-term liability requirements, and, therefore, short-term market variations are inevitable.

The Used Fuel Fund is also subject to the volatility of the capital markets. However, for the Used Fuel Fund, the Province guarantees the rate of return on the fund for the first 2.23 million used fuel bundles.

Regulated – Hydroelectric Segment

(millions of dollars)	**2007**	**2006**
Revenue	**695**	685
Fuel expense	**244**	245
Gross margin	**451**	440
Operations, maintenance and administration	**123**	92
Depreciation and amortization	**68**	66
Property and capital taxes	**11**	18
Income before interest and income taxes	**249**	264

Revenue

(millions of dollars)	**2007**	**2006**
Regulated generation sales [1]	**635**	635
Variance accounts	**15**	(4)
Other	**45**	54
Total revenue	**695**	685

[1] Regulated generation sales included revenue of $158 million and $169 million that OPG received at the Ontario electricity spot market price for generation over 1,900 MWh in any hour during the years ended December 31, 2007 and 2006, respectively.

Regulated – Hydroelectric revenue was $695 million for the year ended December 31, 2007 compared to $685 million in 2006, an increase of $10 million. The increase in revenue was primarily due to higher revenue recorded as a result of regulatory variance accounts, partially offset by the impact of the lower generation volume.

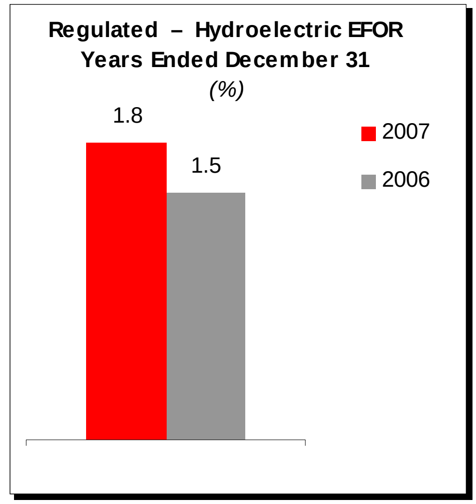
Electricity Prices

For the years ended December 31, 2007 and 2006, the average electricity sales price for the Regulated – Hydroelectric segment was 3.5¢/kWh. The average sales price is based on the fixed price of 3.3¢/kWh for generation up to 1,900 MWh in any hour, and the spot electricity market price for generation above this level.

Volume

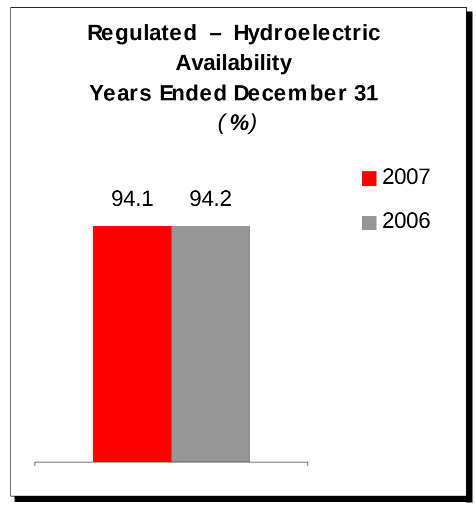
For the year ended December 31, 2007, electricity sales volume was 18.1 TWh compared to 18.3 TWh in 2006. The decrease in electricity sales volume in 2007 was primarily due to lower water levels in Eastern Ontario during the fourth quarter of 2007 compared to the same period in 2006. For the year ended December 31, 2007, volume related to production levels above 1,900 MWh in any hour was 3.3 TWh compared to 3.4 TWh for 2006.

For the years ended December 31, 2007 and 2006, the EFOR for the Regulated – Hydroelectric stations was 1.8 per cent and 1.5 per cent, respectively. The availability for the Regulated – Hydroelectric stations was 94.1 per cent in 2007 compared to 94.2 per cent in 2006. The low EFOR and high availability reflect the continuing strong performance of the Regulated – Hydroelectric stations.



Variance Accounts

OPG is required under a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to establish variance accounts for the Regulated – Hydroelectric segment to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions and differences between forecast and actual ancillary service revenue. For the years ended December 31, 2007 and 2006, OPG recorded revenue of $15 million and a reduction in revenue of $4 million, respectively, primarily as a result of the difference in actual water conditions and ancillary services revenue compared to the forecast provided to the Province for the purpose of establishing regulated prices.

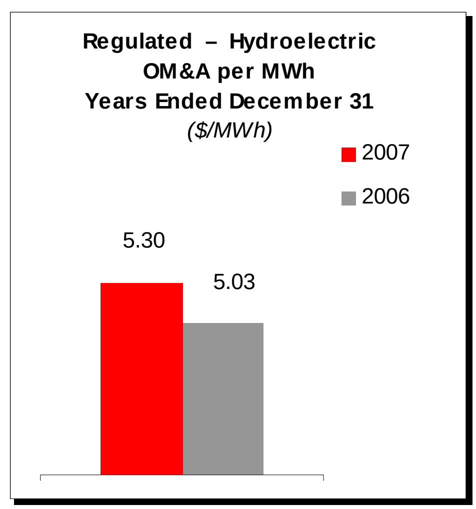


Fuel Expense

OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are classified as fuel expense. Fuel expense for the years ended December 31, 2007 and 2006 was $244 million and $245 million, respectively.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2007 were $123 million compared to $92 million in 2006. The increase in OM&A expenses in 2007 was primarily due to an increase in expense related to past grievances by First Nations.



OM&A expense per MWh for the regulated hydroelectric stations increased to $5.30/MWh in 2007 compared to $5.03/MWh in 2006. OM&A expense per MWh excludes expenses related to past grievances by First Nations.

Depreciation and Amortization

Depreciation expense for the year ended December 31, 2007 was $68 million compared to $66 million in 2006.

Unregulated – Hydroelectric Segment

(millions of dollars)	**2007**	**2006**
Revenue, net of revenue limit rebate	**699**	736
Fuel expense	**81**	88
Gross margin	**618**	648
Operations, maintenance and administration	**207**	189
Depreciation and amortization	**68**	69
Property and capital taxes	**10**	15
Income before other gains and losses, interest and income taxes	**333**	375
Other (gains) and losses	**4**	-
Income before interest and income taxes	**329**	375

Revenue

(millions of dollars)	**2007**	**2006**
Spot market sales, net of hedging instruments	**725**	746
Revenue limit rebate	**(64)**	(44)
Other	**38**	34
Total revenue	**699**	736

Unregulated – Hydroelectric revenue was $699 million for the year ended December 31, 2007 compared to $736 million in 2006. The decrease in revenue of $37 million during the year ended December 31, 2007 compared to 2006 was primarily due to a lower generation volume of 1.2 TWh, partially offset by higher prices.

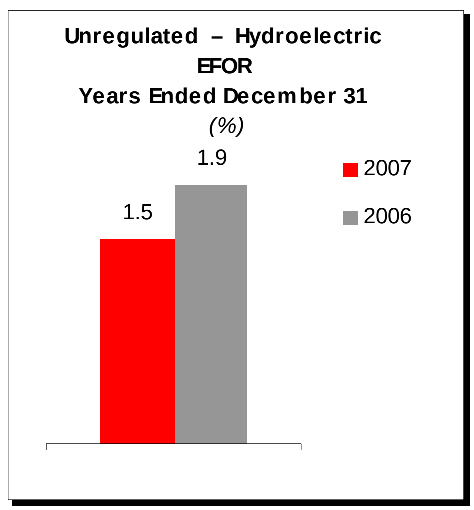
Electricity Prices

After taking into account the revenue limit rebate, OPG's average sales price for its unregulated hydroelectric generation for the years ended December 31, 2007 and 2006 was 4.7¢/kWh and 4.6¢/kWh, respectively.

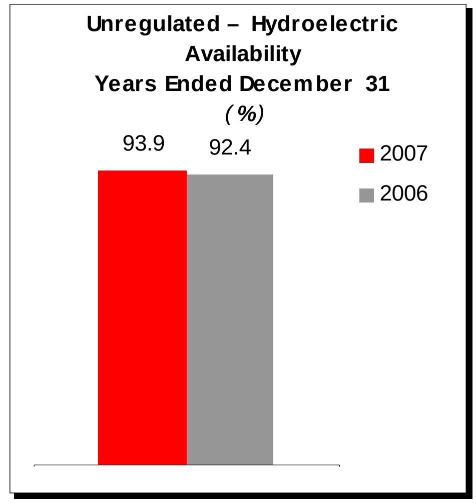
Volume

Electricity sales volume for the year ended December 31, 2007 was 13.8 TWh compared to 15.0 TWh in 2006. The decrease in volume in 2007 was primarily due to lower water levels in Northwestern Ontario during the first two quarters and in Eastern Ontario during the fourth quarter of 2007, compared to the same periods in 2006.

The EFOR for the Unregulated – Hydroelectric stations was 1.5 per cent in the year ended December 31, 2007 compared to 1.9 per cent in 2006. The decrease in EFOR was due to improved equipment performance.



The availability for the Unregulated – Hydroelectric stations was 93.9 per cent for the year ended December 31, 2007 compared to 92.4 per cent for the year ended December 31, 2006. The high availability reflects the continuing strong performance of the Unregulated – Hydroelectric stations due to the continuing investment program.

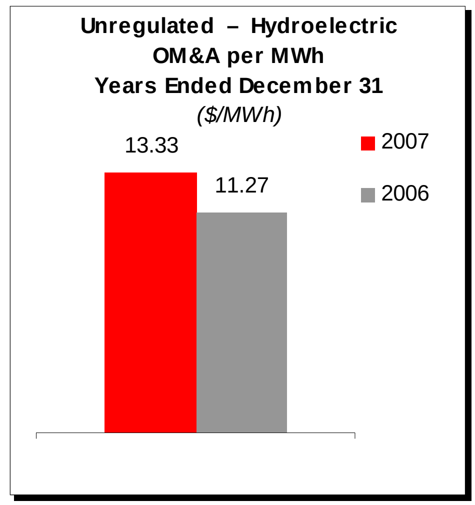


Fuel Expense

Generating stations within this segment are subject to the GRC. Fuel expense was $81 million for the year ended December 31, 2007 compared to $88 million during 2006. The decrease in fuel expense was primarily due to lower generation volume.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2007 and 2006 were $207 million and $189 million, respectively. The increase in OM&A expenses in 2007 compared to 2006 was primarily due to higher expenses for plant improvement initiatives.



OM&A expense per MWh for the unregulated hydroelectric stations was $13.33/MWh for the year ended December 31, 2007 compared to $11.27/MWh in 2006. The increase in 2007 compared to 2006 reflects higher expenses for plant improvement initiatives.

OM&A expense per MWh excludes expense related to past grievances by First Nations.

Depreciation and Amortization

Depreciation expense for the year ended December 31, 2007 was $68 million compared to $69 million in 2006.

Unregulated – Fossil-Fuelled Segment

(millions of dollars)	**2007**	**2006**
Revenue, net of revenue limit rebate	**1,550**	1,313
Fuel expense	**812**	643
Gross margin	**738**	670
Operations, maintenance and administration	**573**	524
Depreciation and amortization	**82**	133
Accretion on fixed asset removal liabilities	**8**	9
Property and capital taxes	**21**	19
Income (loss) before other gains and losses, interest and income taxes	**54**	(15)
Other (gains) and losses	**(20)**	22
Income (loss) before interest and income taxes	**74**	(37)

Revenue

(millions of dollars)	2007	2006
Spot market sales, net of hedging instruments	**1,590**	1,323
Revenue limit rebate	**(163)**	(117)
Other	**123**	107
Total revenue	**1,550**	1,313

Unregulated – Fossil-Fuelled revenue was $1,550 million for the year ended December 31, 2007, an increase of $237 million compared to $1,313 million in 2006. The increase in revenue in 2007 compared to 2006 was primarily due to higher electricity generation of 4.0 TWh.

Electricity Prices

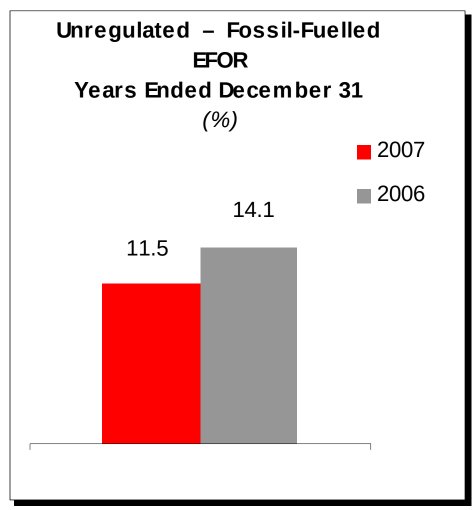
OPG's average sales price net of the revenue limit rebate for its unregulated fossil-fuelled generation for the years ended December 31, 2007 and 2006 was 4.8¢/kWh.

The increase in revenue was also due to higher revenue related to the Lennox RMR contract. In 2007, OPG recorded revenue of $85 million related to the recovery of costs compared to $59 million in 2006. The higher revenue recognized was primarily due to the timing in which OEB approval was issued for the current and prior year contracts. The RMR contract for the period from October 1, 2007 to September 30, 2008 was approved by the OEB in December 2007. The prior year contract, which was effective October 1, 2006, was approved by the OEB in January 2007. As a result, revenue in 2007 included revenue for the period from October 1, 2006 to December 31, 2007.

Volume

Electricity sales volume for 2007 was 29.0 TWh compared to 25.0 TWh during 2006. The increase of 4.0 TWh was primarily due to the lower generation from the nuclear and hydroelectric generating stations.

The EFOR for the Unregulated – Fossil-Fuelled stations for the year ended December 31, 2007 was 11.5 per cent compared to 14.1 per cent in 2006. The lower EFOR in 2007 compared to 2006 was primarily due to much improved performance at the Nanticoke generating station, and continued good performance at the Lennox generating station.

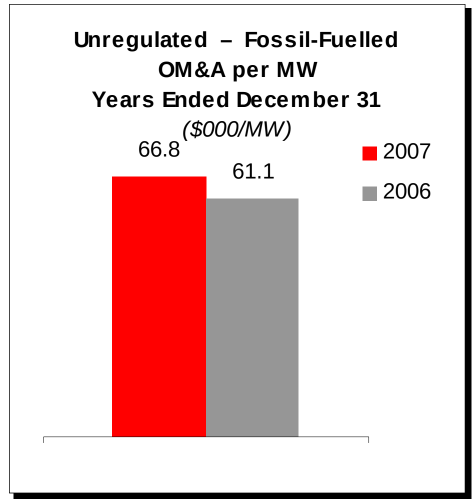


Fuel Expense

Fuel expense was $812 million for the year ended December 31, 2007 compared to $643 million in 2006. The increase in fuel expense in 2007 compared to 2006 was primarily due to higher electricity generation.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2007 were $573 million compared to $524 million in 2006. The increase of $49 million was primarily due to increased maintenance programs and projects related to the extended period over which the coal-fired generating stations will be required to operate, partially offset by the write-off of unrecoverable costs in 2006 related to the cancellation of the Thunder Bay generating station gas conversion project.



Annualized OM&A expense per MW ($/MW) for the unregulated fossil-fuelled stations increased to $66,800/MW for the year ended December 31, 2007 compared to $61,100/MW for the year ended December 31, 2006. The increase primarily reflected the impact of the higher OM&A expenses related to the extension of service lives of the coal-fired generating stations.

Depreciation and Amortization

Depreciation expense for the year ended December 31, 2007 was $82 million compared to $133 million in 2006. The decrease in depreciation expense in 2007 was mainly due to the extension of the service life of all coal-fired generating stations, for purposes of calculating depreciation, due to the delay in the Province's coal replacement program announced by the Ministry of Energy in June 2006. OPG will continue to assess the service lives of the coal-fired stations.

Other Gains and Losses

In 2007, the Company recorded a recovery of $20 million to reflect a change in the estimated costs required to complete decommissioning of the Lakeview generating station. The demolition of the Lakeview generating station was substantially completed during the year.

OPG recognized an impairment loss on the Thunder Bay and Atikokan coal-fired generating stations in 2006 of $22 million, which represented the carrying amount or net book value of these stations. OPG tested the recoverability of the carrying amounts of the coal-fired stations as a result of changes in circumstance, which included a decrease in forecast Ontario spot market prices and the extension of the lives of the coal-fired stations. The fair value of the coal-fired generating stations, which was determined using a discounted cash flow method, was compared to the carrying value of the generating assets to determine the impairment loss. It was determined that the Thunder Bay and Atikokan coal-fired generating stations would not be able to recover their operating and capital expenditures and carrying amount, over their remaining service lives.

Other

(millions of dollars)	**2007**	**2006**
Revenue	**135**	165
Operations, maintenance and administration	**10**	5
Depreciation and amortization	**51**	53
Property and capital taxes	**12**	10
Income before other gains and losses, interest and income taxes	**62**	97
Other (gains) and losses	**10**	-
Income before interest and income taxes	**52**	97

Other revenue for the year ended December 31, 2007 was $135 million compared to $165 million in 2006. The decrease of $30 million was primarily due to significantly lower net trading revenue, partly offset by an increase in investment income from OPG's equity investments.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the year ended December 31, 2007, the service fee was $33 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $4 million for Unregulated – Hydroelectric, $11 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $50 million for the Other category. For the year ended December 31, 2006, the service fee was $30 million for Regulated – Nuclear, $3 million for Regulated – Hydroelectric, $4 million for Unregulated – Hydroelectric, $11 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $48 million for the Other category.

Interconnected markets purchases and sales (including those to be physically settled) and mark-to-market gains and losses (realized and unrealized) on energy trading contracts are disclosed on a net basis in the consolidated statements of income. If disclosed on a gross basis, revenue and power purchases for the year ended December 31, 2007 would have increased by $120 million (December 31, 2006 – $163 million).

The changes in the fair value of derivative instruments not qualifying for hedge accounting are recorded in Other revenue, and are carried on the audited annual consolidated balance sheets as assets or liabilities at fair value. The carrying amounts and notional quantities of the derivative instruments are disclosed in Note 13 in the audited annual consolidated financial statements as at and for the year ended December 31, 2007.

Net Interest Expense

The net interest expense for 2007 was $143 million compared to $193 million for 2006. The decrease in net interest expense in 2007 compared to 2006 was primarily due to the deferral of additional interest expense related to the Pickering A return to service deferral account as required by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario).

Income Taxes

OPG follows the liability method of tax accounting for its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered or refunded through future regulated prices charged to customers.

For the year ended December 31, 2007, there was a net income tax recovery of $51 million, compared to a tax expense of $86 million for 2006. The decrease in income tax expense was largely due to an additional contribution of $334 million to the Nuclear Funds in 2007. Contributions are deductible for tax purposes and no offsetting future tax expense is recognized by OPG due to the use of the taxes payable method to account for income taxes in the regulated segment. In addition, the income tax expense was favourably impacted by a reduction in Federal future income tax rates that were substantively enacted in 2007.

During the years ended December 31, 2007 and 2006, the income tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segment using the liability method by $127 million and $89 million, respectively.

The transition adjustment to the accumulated other comprehensive income on adoption of the financial instruments accounting standards was lower by $4 million than what would otherwise have been recorded had OPG utilized the liability method of tax accounting for the regulated segments.

In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors ("Tax Auditors") with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998*. Although OPG has subsequently resolved some of these issues, there is uncertainty as to how the remaining issues will be resolved. OPG expects to receive a reassessment for its 1999 taxation year. The Company would defend its position through the tax appeals process.

OPG has previously recorded income tax charges related to certain income tax positions that the Company has taken in prior years that may be disallowed. Given the uncertainty as to how these income tax matters will be resolved, OPG has not adjusted its income tax liabilities. Should the ultimate outcome differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its net income could be materially affected either negatively or positively in the period in which the matters are resolved.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing and credit facilities provided by OPG's shareholder. These sources are utilized for continued investment in plant and technologies, and to meet other significant funding obligations including contributions to the pension fund, the Used Fuel and Decommissioning Funds, and to service and repay long-term debt and revenue limit rebate obligations.

	Years Ended December 31	
(millions of dollars)	**2007**	**2006**
Cash and cash equivalents, beginning of year	**6**	908
Cash flow provided by operating activities	**407**	397
Cash flow (used in) investing activities	**(782)**	(650)
Cash flow provided by (used in) financing activities	**479**	(649)
Net increase (decrease)	**104**	(902)
Cash and cash equivalents, end of year	**110**	6

Operating Activities

Cash flow provided by operating activities for 2007 was $407 million compared to cash flow provided by operating activities of $397 million for 2006. The increase in cash flow was primarily due to lower revenue limit rebate payments, the increase in non-electricity generation revenue, and the higher reimbursement of expenditures from the Nuclear Funds associated with the safe storage of Units 2 and 3 at the Pickering A nuclear generating station. The increase in cash flow was partially offset by the one-time contribution of $334 million to the Used Fuel Fund as required by the ONFA, relating to the Bruce Lease, higher operating and maintenance expenditures, and a decrease in cash receipts from electricity sales. The lower revenue limit rebate payments for 2007 compared to 2006 were a result of making a payment of $739 million in the second quarter of 2006 related to the period from April 1, 2005 to December 31, 2005. Revenue limit rebate payments are now made on a quarterly basis.

Investing Activities

OPG is in a capital-intensive business that requires continued investment in plant and technologies to improve operating efficiencies, increase generating capacity of its existing stations, invest in new generating stations and to maintain and improve service, reliability, safety and environmental performance.

Investment in fixed assets during the year ended December 31, 2007 was $666 million compared with $637 million in 2006. The increase in capital expenditures was primarily due to higher investments in the Portlands Energy Centre and fossil-fuelled and nuclear facilities, partially offset by lower investment in the Niagara Tunnel project.

OPG's forecast capital expenditures for 2008 are approximately $800 million, which include amounts for the Niagara Tunnel, Portlands Energy Centre and other development projects.

For the year ended December 31, 2007, investing activities included costs deferred as regulatory assets of $58 million compared to $13 million during the same period in 2006. The amount deferred as regulatory assets during 2007 included interest expense related to the Pickering A return to service deferral account, and non-capital costs incurred for nuclear generation development initiatives.

At December 31, 2007, OPG reclassified its remaining holdings of third-party ABCP notes in the amount of $58 million to long-term investments. A discussion of OPG’s exposure to the ABCP notes is included in the *Recent Developments* section.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility which is divided into two tranches – a $500 million 364-day term tranche maturing May 21, 2008 and a $500 million five-year term tranche maturing May 22, 2012. The longer term tranche was extended from a three-year term to a five-year term, upon renewal of the bank credit facility in May 2007. The total credit facility will continue to be used primarily as credit support for notes issued under OPG’s commercial paper program. As at December 31, 2007, no commercial paper was outstanding (2006 – $15 million). OPG had no other outstanding borrowings under the bank credit facility.

OPG also maintains $25 million (2006 – $26 million) in short-term uncommitted overdraft facilities and $238 million (2006 – $240 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other purposes. At December 31, 2007, there was a total of $205 million of Letters of Credit issued (2006 – $185 million), which included $175 million for the supplementary pension plans (2006 – $159 million) and $16 million related to the construction of the Portlands Energy Centre (2006 – $16 million).

OPG negotiated an agreement with the OEFC to finance the Niagara Tunnel project for up to $1 billion over the duration of the project. The funding is advanced in the form of 10-year notes, on commercial terms and conditions. Advances under this facility commenced in October 2006, and amounted to $240 million as at December 31, 2007, including $80 million of new borrowing during 2007. Similarly, debt financing has been negotiated with the OEFC for OPG’s interest in the Portlands Energy Centre and the Lac Seul project for up to $400 million and $50 million, respectively. Advances under these facilities commenced in December 2006, and totalled $210 million for the Portlands Energy Centre and $20 million for the Lac Seul project as at December 31, 2007. This included $120 million of new borrowing under the Portlands Energy Centre facility during the year ended December 31, 2007.

As at December 31, 2007, OPG’s long-term debt outstanding with the OEFC was $3.7 billion. Although the new financing added in 2006 and 2007 has extended the maturity profile, approximately $2.5 billion of long-term debt must be repaid or refinanced within the next five years. To ensure that adequate financing resources are available beyond its $1 billion commercial paper program backed by the bank credit facility, OPG reached an agreement with the OEFC for a $500 million general corporate facility that is available for the period from June 1, 2007 to March 31, 2008. OPG also reached an agreement with the OEFC for a $950 million credit agreement to refinance senior notes as they mature over the period from September 22, 2007 to September 22, 2009.

In June 2007 and December 2007, OPG issued $100 million and $400 million, respectively, under the general corporate facility. In September 2007, OPG met its debt retirement obligation by issuing $200 million of notes under the $950 million credit facility to refinance the maturing notes. These borrowings will mature in 2017.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2007, are as follows:

(millions of dollars)	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	694	417	325	258	219	374	2,287
Contributions under the ONFA [1]	454	350	350	317	308	1,239	3,018
Long-term debt repayment	400	350	970	375	400	1,170	3,665
Interest on long-term debt	201	183	152	103	75	288	1,002
Unconditional purchase obligations	18	17	16	12	13	174	250
Long-term accounts payable	9	-	-	-	-	-	9
Operating lease obligations	12	12	13	13	13	2	65
Operating licence	20	19	21	22	22	-	104
Pension contributions [2]	260	-	-	-	-	-	260
Other	33	31	34	32	18	42	190
	2,101	1,379	1,881	1,132	1,068	3,289	10,850
Significant commercial commitments:							
Niagara Tunnel	146	258	34	-	-	-	438
Other hydroelectric projects	48	8	1	-	-	-	57
Portlands Energy Centre	59	5	3	3	3	46	119
Total	2,354	1,650	1,919	1,135	1,071	3,335	11,464

[1] Contributions under the ONFA are subject to adjustment due to the ONFA 2006 Approved Reference Plan.

[2] The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuation as at January 1, 2005. The contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, and the timing of funding valuations. Funding requirements after 2008 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The pension contributions are subject to change as a result of the filing of the actuarial valuation in 2008.

Credit Ratings

Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access. The cost and availability of financing is influenced by credit ratings, which are intended to be an indicator of the creditworthiness of a particular company, security or obligation. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets.

At December 2007, OPG has a long-term credit rating of BBB+ by Standard & Poor's ("S&P") and 'A (low)' by Dominion Bond Rating Service ("DBRS"). In November 2007, DBRS confirmed the Unsecured Debt and Commercial Paper ratings of OPG as A (low) and R1 (low), respectively, with stable trends.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's audited consolidated financial position using selected balance sheet data:

Selected balance sheet data *(millions of dollars)*	**As at December 31** **2007**	**2006**
Assets		
Accounts receivable	**315**	230
Property, plant and equipment – net	**12,777**	12,761
Nuclear fixed asset removal and nuclear waste management funds	**9,263**	7,594
Regulatory assets	**356**	251
Long-term investments	**93**	32
Liabilities		
Accounts payable and accrued charges	**953**	989
Revenue limit rebate payable	**100**	40
Long-term debt (including debt due within one year)	**3,853**	3,359
Fixed asset removal and nuclear waste management	**10,957**	10,520

Accounts Receivable

As at December 31, 2007, accounts receivable were $315 million compared to $230 million as at December 31, 2006. The increase of $85 million was primarily due to higher electricity generation volumes in December 2007 compared to December 2006.

Property, Plant and Equipment – Net

Net property, plant and equipment as at December 31, 2007 and December 31, 2006 was $12,777 million and $12,761 million, respectively. The increase was primarily due to additions to fixed assets mostly offset by depreciation expense. The Pickering B nuclear generating station auxiliary power system project was a significant addition to in-service fixed assets during the year ended December 31, 2007.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG is responsible for the ongoing long-term management of radioactive waste materials and used fuel resulting from operations and future decommissioning of its nuclear generating stations. OPG's obligations relate to the Pickering and Darlington nuclear generating stations that are operated by OPG, as well as the Bruce A and B nuclear generating stations that are leased by OPG to Bruce Power.

To fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund, which are funded by OPG in accordance with the ONFA. The Used Fuel Fund is primarily intended to fund future expenditures associated with the long-term management of highly radioactive used nuclear fuel bundles. The Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the long-term management of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third-party custodial and trustee accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities. The Nuclear Funds are referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements. Until December 31, 2006, OPG recorded the assets in the Nuclear Funds as long-term investments at their amortized cost. Up to and including December 31, 2006, gains and losses were recognized only upon the sale of an underlying security. As such, any unrealized gains and losses associated with the investments in the Nuclear Funds were not recognized in OPG's consolidated financial statements. As at December 31, 2006, the value of the Nuclear Funds on an amortized cost basis was $7,594 million.

Effective January 1, 2007, OPG adopted the CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*. As a result of the adoption of this new section, the investments in the Nuclear Funds and the corresponding payables to the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's consolidated financial statements.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA reference plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA reference plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher estimated decommissioning liability.

At December 31, 2006, based on the estimate of costs to complete under the 2006 Approved Reference Plan, the Decommissioning Fund was overfunded on a fair value basis, and underfunded on an amortized cost basis. As a result of the adoption of the financial instruments accounting standards on January 1, 2007, OPG adjusted the investments and the related payables in the Decommissioning Fund to fair value, and recorded a transition adjustment of $519 million to increase opening retained earnings. Subsequently, the investments and the related payables in the Decommissioning Fund are measured at fair value and any changes to the fair values are recognized in income.

After the adjustment to reflect the investments at fair value, on January 1, 2007, the value of the investments in the Decommissioning Fund exceeded the estimated completion costs under the 2006 Approved Reference Plan, and accordingly, the Decommissioning Fund balance was reduced by the amount of the excess funding through the recording of a payable to the Province. The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its earnings at 5.15 per cent, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status. If the Decommissioning Fund were underfunded, the earnings for the Decommissioning Fund would reflect actual fund returns based on the market value of the assets.

At December 31, 2007, the Decommissioning Fund's asset value on a fair value basis was $5,075 million, which continued to exceed the value of the liability as per the 2006 Approved Reference Plan. As a result of the overfunded status, OPG reported a payable to the Province of $3 million, reflecting an amount due to the Province if the Decommissioning Fund were terminated under the ONFA. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to a distribution of an equal amount.

Used Fuel Fund

Under the ONFA, the Province guarantees the annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario CPI ("committed return") for funding related to the first 2.23 million used fuel bundles. OPG recognizes the committed return on the Used Fuel Fund and includes it in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the assets, which includes realized and unrealized returns, is recorded as due to or due from the Province.

Up until December 31, 2006, OPG accounted for the investments in the Used Fuel Fund on an amortized cost basis, with the amount due to or due from the Province being recorded in the consolidated financial statements as the difference between the committed return and the actual return based on realized returns. At December 31, 2006, the Used Fuel Fund included an amount due to the Province of $100 million. The Used Fuel Fund's asset value, after taking into account the committed return and the amount due to the Province, was $3,238 million at December 31, 2006.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Commencing January 1, 2007, the value of the investments held in the Used Fuel Fund is measured at fair value. Accordingly, the Used Fuel Fund's balance increased to $3,876 million to reflect the fair value measurement. The Province guarantees OPG's annual return in the Used Fuel Fund related to the initial 2.23 million used fuel bundles at the committed return, such that any difference between the committed return and the actual return based on fair value would be offset by the change in the related payable or receivable to the Province in the Used Fuel Fund. As a result, OPG did not record a transition adjustment to opening retained earnings for the Used Fuel Fund.

As at December 31, 2007, the Used Fuel Fund asset value on a fair value basis was $4,702 million. The asset value was offset by a payable to the Province of $511 million related to the committed return adjustment.

Regulatory Assets

As at December 31, 2007, regulatory assets were $356 million compared to $251 million as at December 31, 2006. In accordance with the amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), for the year ended December 31, 2007, OPG recorded $131 million in the deferral account related to the increase in OPG's liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management arising from the 2006 Approved Reference Plan. The recognition of the regulatory asset for this deferral account reduced additional expenses resulting from the increase in the nuclear liabilities. These expenses included accretion on the fixed asset removal and nuclear waste management liabilities and depreciation of the carrying value of the related fixed assets. During the year ended December 31, 2007, OPG also deferred $28 million of non-capital costs, including $1 million of interest, incurred for nuclear generation development initiatives in accordance with the regulation.

The increase in the regulatory assets was partially offset by the reduction in the balance of the Pickering A return to service deferral account due to amortization expense of $96 million during the year ended December 31, 2007. The impact of the amortization related to the Pickering A return to service deferral account was partly offset by the deferral of $30 million of interest expense related to the balance in the deferral account as prescribed by the amended regulation.

Long-Term Investments

Long-term investments as at December 31, 2007 were $93 million compared to $32 million as at December 31, 2006. The increase was primarily due to the reclassification to long-term investments of OPG's holding of third-party ABCP.

Accounts Payable and Accrued Charges

Accounts payable and accrued charges as at December 31, 2007 were $953 million compared to $989 million as at December 31, 2006. The decrease was primarily due to changes in timing of expenditures and payments between 2007 and 2006.

Revenue Limit Rebate Payable

The revenue limit rebate payable as at December 31, 2007 was $100 million compared to $40 million as at December 31, 2006. The increase was due primarily to higher Ontario spot market prices during the fourth quarter of 2007, compared to the same period in 2006.

Long-Term Debt (including debt due within one year)

Long-term debt as at December 31, 2007 was $3,853 million compared to $3,359 million as at December 31, 2006. The increase was primarily due to the issuance of long-term debt of $200 million under the credit agreement to refinance senior notes, $200 million related to committed capital projects, and $500 million under the general corporate facility. The increase was largely offset by repayment of long-term debt of $406 million.

Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal (for nuclear and fossil-fuelled generating stations) and nuclear waste management as at December 31, 2007 was $10,957 million compared to $10,520 million as at December 31, 2006. The increase was primarily due to accretion due to the passage of time, partially offset by expenditures on nuclear waste management activities.

Accumulated Other Comprehensive Income

Effective January 1, 2007, OPG adopted the CICA Handbook Section 3865 – *Hedges*, and recognized hedging instruments designated as cash flow hedges in opening AOCI on a net of tax basis. At the same time, the fair value of the hedging instruments was recorded in OPG's audited annual consolidated balance sheets. Subsequent adjustments arising due to these hedging instruments are also recognized in AOCI on a net of tax basis. Prior to January 1, 2007, hedging instruments that qualified for hedge accounting were not carried at fair value on the consolidated balance sheets and were disclosed as off-balance sheet items.

The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized in income upon settlement of the underlying transactions. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity. Foreign exchange derivative instruments are used to hedge the exposure to anticipated USD denominated purchases. Interest rate derivative contracts are used to hedge exposure to changes in market interest rates on variable debt and on debt expected to be issued in the future. When a derivative hedging relationship is expired, the designation of a hedging relationship is terminated, or a portion of the hedging instrument is no longer effective, any associated gains or losses included in AOCI are recognized in the current period's consolidated statement of income. As at December 31, 2007, OPG reported AOCI of $17 million.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements in amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and long-term fixed price contracts.

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. As such, the results of the trust are not consolidated. The securitization provides OPG with an opportunity to obtain an alternative source of cost effective funding. For the year ended December 31, 2007 and 2006, the average all-in cost of funds was 5.1 per cent and 4.4. per cent, respectively, and the pre-tax charges on sales to the trust were $15 million and $13 million, respectively. The current securitization agreement extends to August 2009. Refer to Note 4 of OPG's 2007 annual audited consolidated financial statements for additional information.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries and joint ventures. Such agreements include guarantees, stand-by Letters of Credit and surety bonds.

Hedging Instruments Prior to the Adoption of the Financial Instruments Standards

Prior to the adoption of the financial instruments standards on January 1, 2007, derivative instruments that were designated as hedges were excluded from the audited consolidated financial statements. Such instruments were recognized upon settlement when the underlying transactions occurred. As at December 31, 2006, the deferred gain on such hedging instruments was $41 million.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the audited annual consolidated financial statements as at and for the year ended December 31, 2007. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates and the impact of changes in certain conditions or assumptions, are highlighted below.

Rate Regulated Accounting

A regulation made pursuant to the *Electricity Restructuring Act, 2004* (Ontario) prescribes that most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates receive regulated prices for their output. Under this regulation, OPG is required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005, that are associated with the planned return to service of all units at the Pickering A nuclear generating station. As at December 31, 2007, the deferral account balance was $183 million, consisting of non-capital costs of $232 million related to Unit 1, $19 million related to Units 2 and 3, $20 million of general return to service non-capital costs and interest of $37 million applied at the annual rate of six per cent, as prescribed by the regulation, and net of accumulated amortization of $125 million. As at December 31, 2006, the deferral account balance was $249 million, consisting of non-capital costs of $232 million related to Unit 1, $19 million related to Units 2 and 3, $20 million of general return to service non-capital costs and interest of $7 million applied at the annual rate of six per cent, and net of accumulated amortization of $29 million. OPG commenced the amortization of the deferral account when Unit 1 of the Pickering A nuclear generating station was returned to service in November 2005. The amortization of $96 million was charged to depreciation and amortization expense in 2007 (2006 – $25 million). Upon OPG becoming subject to regulated prices established by the OEB, which is expected in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account through future prices charged to customers on a straight-line basis, over a period not to exceed 15 years.

In addition, under the regulation, OPG is required to establish a variance account to record certain costs incurred and revenues earned or foregone on or after April 1, 2005, due to deviations from the forecast information provided to the Province for the purposes of establishing regulated prices, associated with a number of predefined circumstances. Under the terms of the regulation, the OEB is directed to ensure that OPG either recovers or returns those amounts through future regulated prices charged to customers over a period not to exceed three years, to the extent that the OEB is satisfied that the costs were prudently incurred and are accurately recorded. As at December 31, 2007, OPG reported a regulatory asset of $5 million (2006 – nil) in the variance account related to revenues for ancillary services that were below the forecast provided to the Province for the purposes of establishing regulated prices. As at December 31, 2007, OPG reported a regulatory asset of $7 million (2006 – regulatory liability of $4 million) in a variance account reflecting water conditions that were different to those forecasted. Further, as of December 31, 2007, OPG reported a regulatory asset of $2 million (2006 – nil) reflecting lower generation revenue caused by transmission outages and transmission restrictions.

The other regulatory liability includes a portion of non-regulated revenue earned by OPG's regulated assets, which OPG expects to apply as a reduction to future regulated prices to be established by the OEB. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions including assumptions made in the interpretation of the regulation.

In February 2007, the Province amended the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) to clarify certain sections of the regulation and to require OPG to establish a deferral account in connection with certain changes to its liability for nuclear used fuel management and its liability for nuclear decommissioning and low and intermediate level waste management. The deferral account requires OPG to record a regulatory asset or liability representing the revenue requirement impact associated with the changes in these nuclear liabilities arising from an Approved Reference Plan, approved after April 1, 2005, in accordance with the terms of the ONFA. On December 31, 2006, OPG recorded an increase of $1,386 million in these nuclear liabilities arising from the 2006 Approved Reference Plan.

Commencing in the first quarter of 2007 and up to the effective date of the OEB's first order establishing regulated prices, which is expected to be after March 31, 2008, OPG records a regulatory asset associated with the increase in the nuclear liabilities arising from the 2006 Approved Reference Plan. As at December 31, 2007, OPG recorded $131 million in the deferral account relating to this increase in the nuclear liabilities. The OEB is directed by the regulation to ensure that OPG recovers the balance recorded in the deferral account on a straight-line basis over a period not to exceed three years, to the extent that the OEB is satisfied that the revenue requirement impacts are accurately recorded.

The amendment to the regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) made in February 2007 clarified that the OEB must ensure that OPG recovers, through future regulated prices, all capital and non-capital costs incurred in order to increase the output of, refurbish or add operating capacity to a regulated facility, if these costs are either within budgets approved by OPG's Board of Directors prior to the OEB's first order establishing regulated prices or if the OEB is satisfied that these costs were prudently incurred. A further amendment in February 2008, clarified that the OEB must ensure that OPG recovers the costs incurred and firm financial commitments made in the course of planning and preparing for the development of proposed new nuclear facilities. As a result of these amendments, OPG has recorded a regulatory asset of $28 million for the year ended December 31, 2007, which represents non-capital costs for its nuclear generation development initiatives. Non-capital costs are recorded as a regulatory asset to the extent that they were incurred after April 1, 2005 and were not included in the forecast information provided to the Province for the purposes of setting interim regulated prices.

Income Taxes

OPG is exempt from tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by regulations made under the *Electricity Act, 1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act, 1998* and tax related regulations are relatively new and it has therefore been necessary for OPG, since its inception, to take certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment.

OPG uses the liability method of accounting for income taxes for the unregulated segment of the business and provides future income taxes for temporary differences. The process involves an estimate of OPG's actual current tax liability and an assessment of the Company's future income taxes as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value on the consolidated balance sheets. In addition, OPG has to assess whether the future tax assets can be realized and to the extent that recovery is not considered likely, a valuation allowance must be established.

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business in accordance with paragraphs 102 to 104, inclusive, of the CICA Handbook, Section 3465 – Income Taxes. Accordingly, OPG does not recognize future income taxes related to the rate regulated segments of its business to the extent that these income taxes are expected to be recovered or refunded through future regulated prices charged to customers.

Future tax assets of $234 million (2006 – $228 million) have been recorded on the consolidated balance sheet at December 31, 2007. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards. Because of the adoption of rate regulated accounting, OPG did not record future tax assets of $3,313 million (2006 – $3,514 million), which it would have recorded under the liability method, resulting primarily from temporary differences related to the nuclear fixed asset removal and nuclear waste management provisions.

Future tax liabilities of $439 million (2006 – $477 million) have been recorded on the consolidated balance sheet at December 31, 2007. Because of the adoption of rate regulated accounting, OPG did not record future tax liabilities of $3,749 million (2006 – $3,686 million), which it would have recorded under the liability method, resulting primarily from temporary differences related to the nuclear fixed asset removal and nuclear waste management funds.

Fixed Assets

OPG's business is capital intensive and requires significant investment in property, plant and equipment, and at December 31, 2007, the net book value of OPG's fixed assets was $12,777 million (2006 – $12,761 million).

Property, plant and equipment are tested for recoverability whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Recoverability of property, plant and equipment is determined by comparing the carrying amount of an asset to the undiscounted future net cash flows expected to be generated from the asset over its estimated useful life. In cases where the undiscounted expected future cash flows are less than the carrying amounts, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value, or discounted cash flows.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new and laid-up generating stations, inflation, fuel prices, capital expenditures and station lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors. The Province accepted the advice of the IESO in their June 2006 report that indicated a need for 2,500 MW to 3,000 MW of additional capacity to maintain system reliability. As a result of delays in the plan to replace coal-fired generation by 2009, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension reduced depreciation expense by $64 million in 2006, $126 million in 2007 and will reduce depreciation expense by $46 million in 2008. From 2009 to 2012, the depreciation expense will increase by $59 million in each year. OPG will reassess the service life of the coal-fired stations upon submission of the IPSP, and as subsequently approved by the OEB. Any change to the estimated service life of the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

During 2006, OPG extended the remaining service life of the Pickering B nuclear generating station to 2014 for depreciation purposes after a review of the life limiting components, taking into account recent station capacity factors. The extension reduced depreciation expense by $36 million in 2006 and 2007.

Effective January 1, 2008, the service life of Darlington nuclear generating station, for the purposes of calculating depreciation, was extended by two years to 2019 after a review of the technical analysis for life limiting components. The life extension will reduce depreciation expense by $18 million annually.

The Company has extended the service life of Bruce B nuclear generating station to 2014 for depreciation purposes effective January 1, 2008 after reviewing future capacity plans in the OPA's IPSP, and historical information regarding the service lives of major life limiting components of the station. As a result of the extension, depreciation expense will decrease by $7 million annually. In addition, effective January 1, 2008, OPG extended the service life of Bruce A nuclear generating station to 2035 for depreciation purposes after the review of future capacity plans filed with the OPA and other publicly available information. The extension of the service life of the Bruce A nuclear generating station for depreciation purposes will decrease depreciation expense by $8 million annually.

Pension and Other Post Employment Benefits

OPG's accounting for pension and other post employment benefits are dependent on management's accounting policies and assumptions used in calculating such amounts.

Accounting Policy

In accordance with Canadian GAAP, actual results that differ from the assumptions used, as well as adjustments resulting from changes in assumptions, are accumulated and amortized over future periods and therefore generally affect recognized expense and the recorded obligation in future periods.

Under OPG's policy on accounting for pension and OPEB, certain actuarial gains and losses have not been charged to expense and are therefore not reflected in OPG's pension and OPEB obligations as a result of the following:

- Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.
- For pension and OPEB, the excess of the net cumulative unamortized gain or loss, over 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life.

In addition, past service costs arising from the pension and OPEB amendments are amortized over future periods and therefore affect recognized expense and the recorded obligation in future periods.

At December 31, 2007, the unamortized net actuarial loss and unamortized past service costs for the pension plans and OPEB amounted to $1,993 million (2006 – $1,937 million). Details of the unamortized net actuarial loss and total unamortized past service costs at December 31, 2007 and 2006 are as follows:

	Registered Pension Plan		**Supplementary Pension Plans**		**Other Post Employment Benefits**	
(millions of dollars)	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**
Net actuarial loss (gain) not yet subject to amortization due to use of market-related values	**2**	(677)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of corridor	**960**	931	**16**	15	**206**	207
Net actuarial loss subject to amortization	**384**	854	**6**	5	**332**	492
Unamortized net actuarial loss	**1,346**	1,108	**22**	20	**538**	699
Unamortized past service costs	**64**	82	**3**	3	**20**	25

Accounting Assumptions

Assumptions used in determining projected benefit obligations and the costs for the Company's employee benefit plans are evaluated periodically by management in consultation with an independent actuary. Critical assumptions, such as the discount rate used to measure the Company's benefit obligations, the expected long-term rate of return on plan assets and health care cost projections, are evaluated and updated annually. The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields.

A change in these assumptions, holding all other assumptions constant, would increase (decrease) 2007 costs, excluding amortization components, as follows:

(millions of dollars)	**Registered Pension Plan**	**Supplementary Pension Plans**	**Other Post Employment Benefits**
Expected long-term rate of return			
0.25% increase	(20)	na	na
0.25% decrease	20	na	na
Discount rate			
0.25% increase	(13)	-	(3)
0.25% decrease	13	-	3
Inflation			
0.25% increase	38	1	-
0.25% decrease	(36)	(1)	-
Salary increases			
0.25% increase	10	1	-
0.25% decrease	(10)	(1)	-
Health care cost trend rate			
1% increase	na	na	37
1% decrease	na	na	(29)

na – change in assumption not applicable

Asset Retirement Obligations

OPG's asset retirement obligations are comprised of liabilities for nuclear fixed asset removal and nuclear waste management costs and non-nuclear fixed asset removal costs related to the decommissioning of fossil-fuelled generating stations. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. The estimates of the nuclear liabilities are reviewed on an annual basis as part of the ongoing, overall nuclear waste management program. Changes in the nuclear liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with a corresponding change in the related asset retirement cost capitalized as part of the carrying amount of fixed assets.

The estimates of nuclear fixed asset removal and nuclear waste management costs require significant assumptions in the calculations since the programs run for many years. Significant assumptions underlying operational and technical factors are used in the calculation of the accrued liabilities and are subject to periodic review. Changes to these assumptions, including changes in the timing of programs, technology employed, inflation rate, and discount rate, could result in significant changes in the value of the accrued liabilities.

During the fourth quarter of 2007, the Company re-estimated the costs to complete the remaining work to remediate the Lakeview fossil-fuelled generating station site in 2008. As a result, OPG recorded a recovery of $20 million in other gains or losses to reflect a change in the estimated costs.

In 2006, OPG reviewed and updated the cost estimates under the ONFA 2006 Approved Reference Plan. The 2006 Approved Reference Plan under the ONFA resulted in a $1,386 million increase in OPG's liability for nuclear waste management and decommissioning, and a corresponding increase in the carrying value of the nuclear generating stations to which this liability relates. Changes to the reference plan and cost estimates were mainly due to a change in economic indices, recent industry experience in decommissioning reactors, and additional used fuel and waste quantities resulting from service life extensions.

The increment in the amount of the undiscounted estimated cash flows for OPG's liability for nuclear waste management and decommissioning was discounted using the current credit-adjusted risk-free rate of 4.6 per cent. A ten basis points (0.1 per cent) change in this discount rate would impact the carrying value of the asset retirement obligations by approximately $100 million.

Financial Instruments Measured at Fair Value

Financial assets and liabilities, including exchange traded derivatives, and other financial instruments measured at fair value and for which quoted prices in an active market are available, are determined directly from those quoted market prices.

For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the balance sheet date. This is the case for over-the-counter derivatives, which includes energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and ABCP issued by third-party trusts. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate.

OPG's use of financial instruments expose the Company to various risks, including credit risk, commodity price risk, and foreign currency and interest rate risk. A discussion of how OPG manages these and other risks are in the *Risk Management* section.

Changes in Accounting Policies

Financial Instruments

On January 1, 2007, the Company adopted the CICA Handbook Sections 3855, *Financial Instruments – Recognition and Measurement*, 3865, *Hedges*, 1530, *Comprehensive Income*, 3251, *Equity*, and 3861, *Financial Instruments – Disclosure and Presentation*. As a result of adopting these standards, OPG has recorded transition adjustments to opening retained earnings of $513 million and accumulated other comprehensive income ("AOCI") of $21 million. Comparative amounts for prior periods have not been restated. The impact of adoption is further disclosed in Note 13 to the audited annual consolidated financial statements.

Financial instrument assets include cash and cash equivalents, accounts receivable, nuclear fixed asset removal and nuclear waste management funds, and derivative instruments. Financial instrument liabilities include accounts payable and accrued charges, short-term notes payable, long-term debt and derivative instruments.

Future Changes in Accounting Policies and Estimates

Capital Disclosures and Financial Instruments

In December 2006, the CICA issued three new accounting standards: Handbook Section 1535, *Capital Disclosures* ("Section 1535"), Handbook Section 3862, *Financial Instruments – Disclosures* ("Section 3862"), and Handbook Section 3863, *Financial Instruments – Presentation* ("Section 3863"). These new standards are effective for the Company beginning January 1, 2008.

Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance.

Sections 3862 and 3863 replace Handbook Section 3861, *Financial Instruments – Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

Inventories

The CICA issued a new accounting standard, Section 3031, *Inventories*, in March 2007, which is based on International Accounting Standard ("IAS") 2. The new section replaced the existing Section 3030, *Inventories*. Under the new section, inventories are required to be measured at the "lower of cost and net realizable value", which is different from the existing guidance of "lower of cost and market". The new section also allows the reversal of any write-downs previously recognized. Further, due to the changes in the section and the consequential amendments, some of OPG's critical spare parts currently reported as materials and supplies on OPG's consolidated balance sheets will be accounted for as property, plant and equipment. The new accounting standard and the consequential amendments are effective for OPG beginning January 1, 2008. OPG reclassified significant critical spare parts of $19 million, net of accumulated depreciation, to property, plant and equipment in 2008.

Accounting for Regulatory Operations

In December 2007, the CICA revised its guidance on accounting for rate-regulated operations. The revision resulted in amendments to Handbook Sections 1100, *Generally Accepted Accounting Principles*, and 3465, *Income Taxes*, and Accounting Guideline 19 ("AcG-19"), *Disclosures by Entities Subject to Rate Regulation,* as follows:

- to remove the temporary exemption pertaining to the application of Section 1100 to rate-regulated operations, including the elimination of the opportunity to use industry practice as an acceptable basis for recognition and measurement of assets and liabilities arising from rate regulation;

- to amend Section 3465 to require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers; and
- to amend AcG-19, as necessary, as a result of amendments to Sections 1100 and 3465.

As a result of the changes to Section 3465, OPG will be required to recognize future income taxes associated with its rate-regulated operations in the same manner as it currently recognizes future income taxes for its unregulated operations. OPG will apply the changes prospectively to interim and annual financial consolidated statements beginning January 1, 2009. OPG is currently evaluating the impact of implementing these changes on its consolidated financial statements.

RISK MANAGEMENT

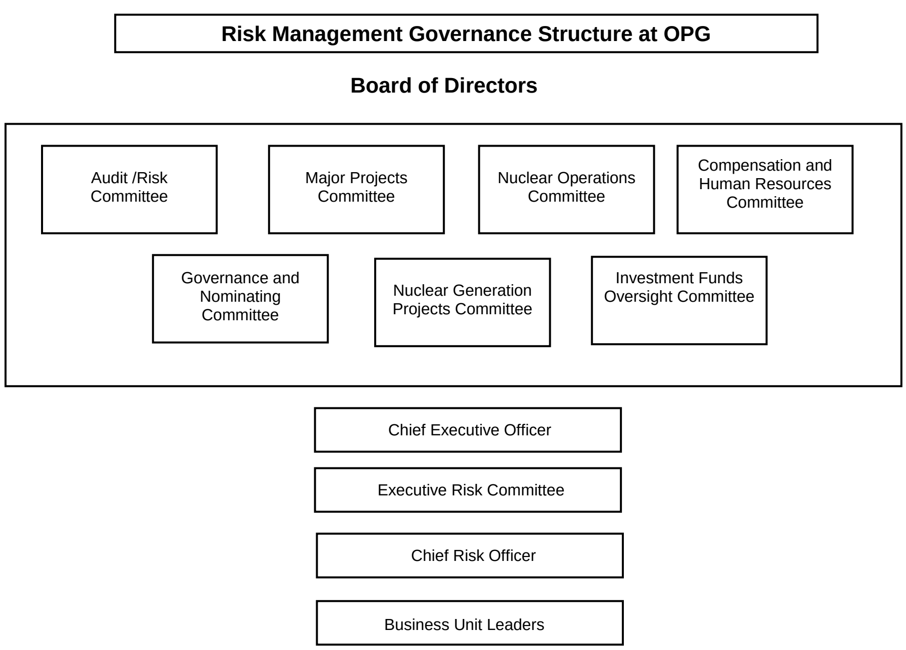
Governance Structure

OPG operates as an independent commercial organization within a complex and highly regulated industry. The Company must effectively manage a wide array of financial, operational and commercial risks that arise from its various business activities.

To manage these risks, OPG's Board of Directors has approved, and management has implemented, a risk management governance structure designed to effectively identify, measure, monitor and report on key risk management activities across the Company. These activities are coordinated by a centralized risk management group which is led by the Chief Risk Officer. The risk management group is responsible for providing independent assessments of the effectiveness of management's risk mitigation activities and/or actions to the Audit and Risk Committee of the Board on a quarterly basis.

Many of the risks identified by OPG can be managed effectively through various mitigation activities and/or actions. However, some risks are difficult to effectively mitigate as they involve external factors or result from events unrelated to OPG. For instance, changes to various environmental, financial, and nuclear safety regulations can all have a significant impact on OPG's ability to meet its business plan objectives.

Notwithstanding these challenges, OPG continues to focus on managing all of the key risks that it has identified in order to meet its strategic objectives and business plan goals. An illustration of OPG's governance structure that supports its risk management function is provided below.



Electricity Generation

OPG is exposed to the financial impacts of uncertain output from its generating stations. The amount of electricity generated by OPG is affected by a number of factors including fuel supply, equipment malfunction or deterioration, weather, maintenance requirements, water levels, and regulatory and environmental regulations. The primary unfavourable impacts of these factors are higher cost of operations, reduced revenues and the potential derating of a generating unit resulting in production that is lower than its normal level of output.

Nuclear Generation

The uncertainty associated with the volume of electricity produced by OPG's nuclear generating units is primarily driven by the condition of the plant components and systems, which are subject to the effects of aging. The generating stations have extensive inspection and maintenance programs that are designed to monitor and identify actions needed to keep the generating stations within design parameters and to maintain reliability.

In certain cases, deterioration of plant components progresses in an unexpected manner, resulting in the need to increase monitoring, conduct extensive repairs or undertake additional remedial measures. In some instances, derating of the units may be required in order to maintain a safe operating margin. When such a technology risk first appears or is suspected, a specific monitoring program is established. If the risk exposure materializes, a resolution program is initiated. The primary impact of these technology risks is an increase in the long-term cost of operations. In some instances, mitigation creates additional outage work, which may result in outage extensions.

Hydroelectric Generation

OPG's hydroelectric generating performance is partially dependent on the availability of water, which can vary from year to year due in large part to the weather. The inherent uncertainty in forecasting water levels introduces a significant degree of uncertainty with respect to forecasting hydroelectric generation. OPG manages this risk by using production forecasting models that incorporate unit efficiency characteristics, water flow conditions and outage plans. Water flows and outage conditions are assessed, monitored and adjusted on a regular basis.

OPG's hydroelectric generating stations vary in age from 13 to 108 (DeCew Falls I) years, with an average age of over 73 years. Over 75 per cent of the hydroelectric generating capacity is over 50 years old. Due to the variability and age of some of the equipment and civil components, there is a risk that some facilities will require significant work and funding to sustain their reliability. OPG manages these reliability risks by conducting ongoing maintenance of critical components, engineering reviews, plant condition assessments, and inspections to identify future work necessary to sustain and, if necessary, upgrade the plant and its equipment. Over the next five years, OPG plans to continue its reinvestment in its hydroelectric assets to address issues associated with the age of the equipment in order to maintain the performance of its assets. The success of the program is monitored through the measurement of reliability. OPG's hydroelectric assets continue to significantly outperform relevant North American reliability-related benchmarks.

The hydroelectric business segment operates 238 dams across the province. To mitigate and manage the risks associated with the operation of these dams, OPG has a dam safety program that performs ongoing maintenance, upgrades and rehabilitation work. OPG also undertakes ongoing dam safety reviews and monitoring, and ad hoc peer reviews. Emergency preparedness and response plans have been established for all facilities to mitigate losses in the event of a dam failure or uncontrolled release of water.

Fossil-Fuelled Generation

Electricity generation from fossil-fuelled generation units can be unfavourably affected by plant and equipment failures. OPG manages and mitigates these risks by performing ongoing maintenance and undertaking engineering reviews, condition assessments and critical reviews of maintenance processes. OPG uses the results of these reviews and assessments to implement changes to inspection, maintenance, and capital project programs. The performance of OPG's fossil-fuelled stations is measured by their availability to produce electricity when called upon. During 2007, OPG's fossil-fuelled generating stations have achieved significant reliability improvements.

Market Risks

There are a number of discrete kinds of market risks that can impact OPG's financial performance. Many of these risks arise due to OPG's exposure to volatility in equity prices, prices or supply of various commodities, foreign exchange and interest rates, as well as the impact that unexpected events have on credit, global liquidity and regional trading markets. In order to respond to this complex array of risks, OPG manages these risks from a conservative perspective in order to reduce the uncertainty or mitigate the potential negative impact that these events could have on financial results. However, despite these measures, some of OPG's exposures to financial risks cannot be completely or effectively mitigated due to regulatory constraints or due to the nature of the risk itself.

Equity Prices

Equity price risk is the risk of loss or unexpected volatility due to decline in the value of individual equities and/or equity indices. OPG's specific exposure to equity prices relates to the value of the Company's Nuclear Funds and pension funds that contain a significant allocation to domestic and international equity markets. These funds are managed by OPG to generate investment returns sufficient to meet their respective financial obligations over time.

To manage this risk, OPG's Nuclear Funds and pension fund have investment policies and procedures in place to set out the investment framework of the funds, including the investment assumptions, permitted investments, and various investment constraints. Such policies and procedures are approved annually by OPG's Investment Funds Oversight Committee of the Board of Directors. For the Nuclear Funds, such policies and procedures are also agreed to jointly with the Province, under ONFA.

Commodities

Changes in the market price of electricity or of the fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios to the extent that trading liquidity in the relevant commodities markets provides the economic opportunity to do so. To manage fuel price risk, OPG has a fuel hedging program, which includes using fixed price and indexed contracts, as well as approved derivative products.

OPG's revenue is also affected by changes in the market price of electricity. For 2008, a $1/MWh increase in the spot market price of electricity above the revenue limit would increase OPG's gross margin by approximately $17 million, while a $1/MWh decrease below the revenue limit would decrease gross margin by approximately $45 million. The impact of the revenue limit rebate mechanism results in an asymmetrical impact on gross margin when the price of electricity increases and decreases.

The percentages of OPG's expected generation, emission requirements and fuel requirements hedged are shown below:

	2008	2009	2010
Estimated generation output hedged [1]	92%	72%	60%
Estimated fuel requirements hedged [2]	95%	80%	52%
Estimated nitric oxide ("NO") emission requirement hedged [3]	100%	100%	100%
Estimated SO_2 emission requirement hedged [3]	100%	100%	100%

[1] Represents the portion of megawatt hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under regulated pricing commitments, agreements with the IESO, OPA auction sales and the revenue limit on OPG's non-prescribed assets (which ends on April 30, 2009).

[2] Represents the approximate portion of megawatt hours of expected generation production (and fossil year-end inventory target) from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangements or obligations in order to secure either the expected availability and/or price of fuel and/or fuel related services. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios. Since production from hydroelectric facilities is primarily influenced by expected weather and weather patterns, fuel hedge ratios for hydroelectric facilities are assumed to be 100 per cent.

[3] Represents the approximate portion of megawatt hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulation 397/01.

Foreign Exchange and Interest Rates

OPG's foreign exchange exposure is attributable to two primary factors: United States dollar denominated transactions such as the purchase of fossil fuels; and the influence of USD denominated commodity prices on Ontario electricity spot market prices. The magnitude and direction of the exposure to the USD is affected by generation reliability and the price volatility of USD denominated commodities. OPG currently manages its exposure using forwards and various derivative products to periodically hedge its anticipated USD exposures according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative products. The management of these risks is undertaken by hedging the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated new financing. As of December 31, 2007, OPG had total interest rate swap contracts outstanding with a notional principal of $692 million.

Credit

OPG's credit risk exposure is comprised of two major components: the first is derived from its sales of electricity and the second is derived from its purchases of services and products. As the majority of OPG's sales are through the IESO-administered spot market, OPG management accepts this credit risk due to the IESO's primary role in the Ontario electricity market. This confidence is based on the IESO's own credit risk management policies and practices, which require all spot market participants to meet specific standards for creditworthiness. Additionally, in the event of a participant default, the loss is shared on a pro-rata basis among all participants thus reducing the specific exposure to OPG.

The following table provides information on credit risk from energy sales and trading activities as at December 31, 2007:

			Potential Exposure for Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3]	**Number of Counterparties**	**Counterparty Exposure**
		(millions of dollars)		*(millions of dollars)*
Investment grade	165	115	5	85
Below investment grade	43	60	5	48
IESO [4]	1	453	1	453
Total	209	628	11	586

1 Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.
2 OPG's counterparties are defined by each master agreement.
3 Potential exposure is OPG's assessment of maximum exposure over the life of each transaction at a 95 per cent confidence interval.
4 Credit exposure to the IESO peaked at $883 million during the year ended December 31, 2007 and at $1,029 million during the year ended December 31, 2006.

OPG's second element of credit risk relates to the exposures created by companies ("counterparties") who are contracted to provide services or products. OPG manages this risk using a comprehensive credit risk management function that independently evaluates all major counterparties and provides continuous input to business units who acquire these services.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects and related maintenance programs at generating stations. In addition, the Company has other significant disbursement requirements including investment in new generating capacity, annual funding obligations under the ONFA, pension funding and continuing debt maturities with the OEFC. OPG must ensure it has the borrowing capacity and access to the necessary financing sources to fund its capital requirements. A discussion of corporate liquidity is included in the *Liquidity and Capital Resources* section.

OPG's has financial exposure to several third-party ABCP trusts as a result of short-term investment activities. The exposure, which was initially $103 million, has been reduced to $58 million as at December 31, 2007 following the settlement of $45 million of notes held with Skeena Capital Trust. OPG's remaining exposure to third-party ABCP Trusts is not considered material and will have no adverse impact on OPG's liquidity. A discussion of OPG's exposure to third-party ABCP is included in the *Recent Developments* section.

Trading

Open trading positions are subject to measurement against Value at Risk ("VaR") limits. For a given portfolio, VaR measures the possible future loss in terms of market value, which under normal market conditions will not be exceeded within a defined probability and time period. VaR utilization ranged between $0.5 million and $2.0 million during the year ended December 31, 2007, compared to $1.2 million and $3.4 million during the year ended December 31, 2006. VaR utilization is closely monitored in order to ensure compliance with approved limits.

Trading liquidity continues to be constrained in Ontario and interconnected markets due to broader energy market fundamentals. In addition, the revenue limit reduces customer exposure to electricity spot market prices and further limits trading activity.

Human Resource Risks

OPG continues to face demographic risks and resourcing gaps. To address these risks, OPG has implemented plans and programs designed to meet current and future business needs for human resources and critical skills. Business leaders are actively involved in the review of workforce needs and plans to resource critical skills and jobs in their functional lines of business. Initiatives continue in support of OPG's employment brand, youth outreach and educational relations. In the third quarter of 2007, OPG launched its largest campus recruitment program to date, participating in career fairs and information sessions on campuses across Ontario and on the East Coast.

In addition, OPG's commitment to building and strengthening internal capabilities was evidenced by the introduction of an integrated leadership competency model, focused efforts in terms of succession planning, and the introduction of a new supervisory training program.

Environmental Risks

Changes to environmental laws or delays in implementing the current timetable of the Province's coal replacement policy could create compliance risks that may be addressed by the installation of additional equipment or control technologies, the purchase of additional emission reduction credits, or by constraining production from the fossil-fuelled fleet. In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges. Further, some of OPG's activities have the potential to cause contamination to land or water that may require remediation. The potential liability associated with any of these events could have a material adverse effect on the business.

In order to meet the federal and provincial emission targets previously identified under the heading, *Recent Developments, Climate Change Plan*, there is a risk that OPG will be required to either reduce certain emissions or purchase offsets, which could have a material adverse impact to OPG.

Major Project Risks

OPG is involved with several major development projects, including: the Niagara Tunnel, Lac Seul, Portlands Energy Centre, other projects supporting operating units, hydroelectric development projects, the potential refurbishment of existing nuclear stations, and the consideration of new nuclear units at OPG's Darlington nuclear generation site. There is a risk that OPG will have insufficient resources to implement several large projects concurrently. This risk is especially critical given the complexity, long project timelines, and inherent risks associated with these projects.

OPG has taken many steps to address the unique challenges relating to the various development projects. OPG utilizes Owner's Representative services to acquire the necessary technical expertise to monitor and control projects. Also, major projects have been contracted on a "design-build at a fixed-price" basis, which provides OPG with greater cost certainty. In addition, certain projects have liquidated damages built into the contracts to mitigate late in-service by the respective contractor. However, this contracting strategy does not fully mitigate the risk to OPG's reputation, as Owner, in the event of prolonged scheduling delays.

For nuclear related projects, OPG has established a new division to evaluate the viability of the refurbishment of existing nuclear facilities in order to extend their life. The activities of this division include completing plant condition and environmental assessments, developing appropriate project infrastructures and confirming various industry regulatory requirements.

Regulatory Risks

Effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. These prices will remain in effect until at least March 31, 2008.

In November 2007, OPG filed an application with the OEB for new payment amounts for its regulated facilities effective April 1, 2008, for a 21-month period. Effective some time after March 31, 2008, the OEB will establish new regulated prices for electricity generated by OPG's regulated facilities. The process of setting new regulated prices is inherently uncertain. There is a risk that new prices established by the OEB may not provide for recovery of all of OPG's costs, or may not provide an appropriate rate of return. Despite the fact that some costs may not be included within the new prices, these expenditures may still be necessary to maintain the reliability and safety of OPG's regulated generating assets.

The uncertainty associated with nuclear regulatory requirements is primarily driven by plant deterioration, technology risks and changes to technical codes. Remaining current with and addressing these requirements adds to the cost of operations and in some instances, it may result in a reduction in the productive capacity of a plant, or in the earlier than planned replacement of a plant component. As there is currently no preset or prescribed methodology to assess nuclear safety, OPG and the regulator have occasionally While such situations are normally resolved through subsequent detailed reviews and discussions, they contribute to the uncertainty of the regulatory requirements. The primary impact of this risk is an increase in the long term cost of operations; in some instances these are accompanied by outages necessary to deal with the risk.

Regulatory uncertainty also remains a significant risk for all activities and programs related to nuclear plant life extension, rehabilitation, new plant construction and decommissioning (such as the Pickering A Units 2 and 3 safe storage project) as existing standards and regulatory requirements may not readily extend to new conditions or designs. The primary effects of this risk are project delays and higher development costs.

OPG manages uncertainty associated with nuclear regulatory requirements by maintaining close contact with the regulator and issuers of standards and codes for the early identification and discussions of issues. Together with other industry members, OPG is also investigating the use of a common, risk-based mode of assessment and regulation.

Reputation Risks

Maintaining a good reputation is important to every company. OPG focuses on building and maintaining a good reputation through many practices, including appropriate corporate governance practices, transparency, effective communications with stakeholders, and continuous improvement initiatives to manage and mitigate various risks across the Company that could impact its reputation.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

(millions of dollars)	**Revenue** 2007	**Expenses** 2007	Revenue 2006	Expenses 2006
Hydro One				
Electricity sales	**28**	**-**	34	-
Services	**-**	**12**	-	13
Province of Ontario				
GRC water rentals and land tax	**-**	**129**	-	132
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**(130)**	-	96
Decommissioning Fund excess funding	**-**	**(291)**	-	(7)
OEFC				
GRC and proxy property tax	**-**	**199**	-	205
Interest income on receivable	**-**	**(6)**	-	(29)
Interest expense on long-term notes	**-**	**187**	-	203
Capital tax	**-**	**32**	-	51
Income taxes	**-**	**(51)**	-	86
Indemnity fees	**-**	**-**	-	2
IESO				
Electricity sales	**5,094**	**104**	5,029	146
Revenue limit rebate	**(227)**	**-**	(161)	-
Ancillary services	**145**	**-**	132	-
Other	**-**	**1**	1	1
	5,040	**194**	5,035	907

At December 31, 2007, accounts receivable included $2 million (2006 – $8 million) due from Hydro One and $211 million (2006 – $71 million) due from the IESO. Accounts payable and accrued charges at December 31, 2007 included $2 million (2006 – $2 million) due to Hydro One.

Corporate Governance

National Instrument 58-101, *Disclosure of Corporate Governance Practices*, has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. Information with respect to OPG's Board of Directors is as follows:

Board of Directors and Directorships

OPG's Board of Directors is made up of individuals with substantial capability in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board exercises its independent supervision over management as follows: the majority of members of the Board of Directors are independent of the Company; meetings of the Board of Directors are held at least six times a year; a formal Charter for the Board of Directors, and for each Board Committee has been adopted; each Board Committee is chaired by an independent director; and a portion of each Board and Committee meeting is reserved for directors to meet without management present.

All directors listed are independent within the meaning of Section 1.4 of Multilateral Instrument 52-110 of the Canadian Securities Administrators ("MI 52-110") except for Jim Hankinson who is the President and Chief Executive Officer ("CEO") of OPG and Gary Kugler who is the Chairman of the Nuclear Waste Management Organization.

The following are the directors of OPG as at February 28, 2008.

Jake Epp
Age: 68
Calgary, Alberta, Canada

Jake Epp was appointed as Chairman of the Board of Ontario Power Generation Inc. in April 2004. He held the position of interim Chairman from December 2003 until his current appointment. Jake Epp was a member of the provincial government's review committee that was created in December 2003 and headed by John Manley, to look at OPG's future role in the province's electricity market; examine its corporate and management structure; and decide whether OPG should go ahead with refurbishing three more nuclear reactors at the Pickering A nuclear power plant. The committee's report was presented to the government in March 2004. In May 2003, he was appointed by the Ontario government to lead a panel to review the delays and cost overruns at the Pickering A nuclear generating station. The findings of the report were released in December 2003. He is also certified by the Institute of Corporate Directors.

Board/Committee Membership:	**2007 Attendance:**	
Board (since December 2003)	11 of 11	100%
Compensation and Human Resources Committee (since November 2004)	11 of 11	100%
Governance and Nominating Committee (since August 2005)	3 of 3	100%
Nuclear Generation Projects Committee (since November 2006)	5 of 5	100%
The Board Chair attends all other committee meetings	22 of 23	96%

Principal Occupation: Chairman, Ontario Power Generation Inc. Board of Directors

Board Memberships for other Reporting Issuers: QHR Technologies, Inc.

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

James F. Hankinson
Age: 64
Toronto, Ontario, Canada

James Hankinson was appointed as President and Chief Executive Officer of Ontario Power Generation Inc. in May 2005. He has broad management experience in energy, transportation, resource and manufacturing-based businesses. He served as President and Chief Executive Officer of New Brunswick Power Corporation from 1996 to 2002, and during that time, had a significant impact on improving the operational and financial position of the company. In 1973, he joined Canadian Pacific Limited, and served as Chief Operating Officer from 1990 to 1995. A chartered accountant, Mr. Hankinson has a Master of Business Administration from McMaster University, and an Honourary Doctor of Laws degree from Mount Allison University. He also sits on the boards of CAE Inc. and Maple Leaf Foods Inc.

Board/Committee Membership:	**2007 Attendance:**	
Board (since December 2003)	11 of 11	100%
The President and CEO attends all committee meetings with the exception of select Compensation and Human Resources Committee meetings	35 of 37	95%

Principal Occupation: President and Chief Executive Officer, Ontario Power Generation Inc.

Board Memberships for other Reporting Issuers: CAE Inc.
Maple Leaf Foods Inc.

Independence from OPG: Not Independent (Member of Management)

Interlocking Directorships on Boards of other Reporting Issuers: None

Donald Hintz
Age: 65
Punta Gorda, Florida, U.S.A.

Donald Hintz is the retired President of Entergy Corporation, where he was responsible for Entergy's 30,000 megawatts of generating assets, including 10 nuclear plants. Prior to his appointment as President he spent seven years as President and CEO of Entergy Operations Inc. Here he oversaw the improvement of Entergy's nuclear operations to top quartile performance. Mr. Hintz currently serves on the Board of Entergy Corporation and is the President of the American Nuclear Society, an international organization of more than 10,500 nuclear scientists and engineers. He has a Bachelor of Science in Chemical Engineering from the University of Wisconsin, and has completed the Utility Executive Program and the Advanced Management Program at the University of Michigan and the Harvard Business School, respectively.

Board/Committee Membership:	**2007 Attendance:**	
Board (since October 2004)	9 of 11	82%
Compensation and Human Resources Committee (since November 2004)	10 of 11	91%
Nuclear Operations Committee* (since November 2004)	3 of 4	75%
Nuclear Generation Projects Committee (since November 2006)	3 of 5	60%

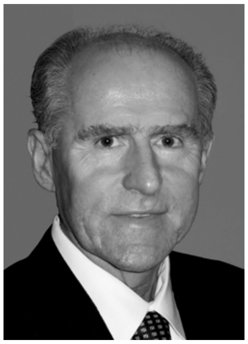
* Chair of Committee

Principal Occupation: Retired President of Entergy Corporation

Board Memberships for other Reporting Issuers: Entergy Corporation

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None



Gary Kugler
Age: 67
Burlington, Ontario, Canada

Dr. Gary Kugler is the retired Senior Vice President, Nuclear Products and Services of Atomic Energy of Canada, Limited (AECL), where he was responsible for all of AECL's commercial operations, including nuclear power plant sales and services world-wide. During his 34 years with AECL, he also held various technical, project management, and business development positions. Prior to joining AECL, he served as a pilot in the Canadian air force. Dr. Kugler currently serves as Chairman of the Nuclear Waste Management Organization’s Board of Directors. He holds a Bachelor of Science degree in honours physics and a Ph.D. in nuclear physics from McMaster University.

Board/Committee Membership:	2007 Attendance:	
Board (since September 2004)	9 of 11	82%
Audit and Risk Committee (since November 2004)	3 of 4	75%
Governance and Nominating Committee (since August 2005)	3 of 3	100%
Nuclear Operations Committee (since November 2004)	4 of 4	100%
Nuclear Generation Projects Committee (since November 2006)	5 of 5	100%

Principal Occupation: Chairman, Nuclear Waste Management Organization

Board Memberships for other Reporting Issuers: None

Independence from OPG: Not Independent (Chairman of Nuclear Waste Management Organization)

Interlocking Directorships on Boards of other Reporting Issuers: None

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M. George Lewis
Age: 47
Toronto, Ontario, Canada

George Lewis is Group Head, Wealth Management, RBC Financial Group. Mr. Lewis is also Chairman and Chief Executive Officer of RBC Asset Management Inc. Prior to his current appointment, Mr. Lewis was Head of Wealth Management for the Canadian Personal and Business segment of RBC FG, Canada’s largest bank. Formerly he was Managing Director, Head of Institutional Equity Sales, Trading and Research with RBC Capital Markets and was Canada’s top-rated analyst for 3 consecutive years. He has extensive experience in the investment industry and has a Master of Business Administration degree with distinction from Harvard University, a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto and is a chartered financial analyst and chartered accountant, as well as being certified by the Institute of Corporate Directors. Mr. Lewis serves on the Board of Directors of the Centre for Addiction and Mental Health Foundation and the Toronto Symphony Orchestra and is Chair of the Bishop’s Company of the Anglican Diocese of Toronto, as well as a member of the Cabinet of the United Way of Greater Toronto and Patron.

Board/Committee Membership:	2007 Attendance:	
Board (since February 2005)	10 of 11	91%
Audit and Risk Committee* (since February 2005)	4 of 4	100%
Investment Funds Oversight Committee* (since March 2005)	3 of 3	100%

* Chair of Committee

Principal Occupation: Group Head, Wealth Management, RBC Financial Group

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

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David J. MacMillan
Age: 55
Barnes, London, United Kingdom

David MacMillan is a Managing Director of Good Energies, a European based multi-billion dollar private equity fund that invests in renewable energy technology companies and renewable energy companies and projects worldwide. He is also a Non-Executive Director of InterGen N.V., an international owner and operator of utility scale power generation plants. He has extensive international experience in the power generation sector with a focus on investment strategy and financing. Mr. MacMillan was also a former Director of Killingholme Power Limited. Mr. MacMillan holds a B.A. and a M.A. of Economics from McGill University.

Board/Committee Membership:	**2007 Attendance:**	
Board (since September 2004)	11 of 11	100%
Nuclear Generation Projects Committee (since November 2006)	4 of 4	100%
Major Projects Committee*	12 of 12	100%

* Chair of Committee

Principal Occupation: Partner – Good Energies

Board Memberships for other Reporting Issuers: InterGen N.V.

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Corbin A. McNeill Jr.
Age: 68
Jackson, Wyoming, U.S.A

Corbin McNeill is the retired Chairman and Co-Chief Executive Officer of Exelon Corporation, which was formed by the merger of PECO Energy and Unicom Corp. At PECO, he had been Chairman, President and CEO, having joined PECO in 1988 as Executive Vice President, Nuclear. Prior to PECO, he oversaw nuclear operations at the Public Service Electric and Gas Company and the New York Power Authority. Mr. McNeill currently serves as a Director of Owens-Illinois Inc. and Portland General Electric. Mr. McNeill has a Bachelor of Science degree from the U.S. Naval Academy and has completed the Executive Management Program at the Standford University.

Board/Committee Membership:	**2007 Attendance:**	
Board (since October 2004)	11 of 11	100%
Governance and Nominating Committee* (since August 2005)	3 of 3	100%
Investment Funds Oversight Committee (since May 2005)	3 of 3	100%
Nuclear Operations Committee (since November 2004)	4 of 4	100%
Nuclear Generation Projects Committee* (since November 2006)	5 of 5	100%

* Chair of Committee

Principal Occupation: Retired Chairman and Co-Chief Executive Officer of Exelon Corporation

Board Memberships for other Reporting Issuers: Owens-Illinois Inc.
Portland General Electric Company

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Peggy Mulligan
Age: 49
Mississauga, Ontario Canada

Peggy Mulligan is the former Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to Linamar, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. Peggy Mulligan is a Trustee of Resolve Business Outsourcing Income Fund. She holds a B. Math (Honours) from the University of Waterloo and was named an FCA by the Institute of Chartered Accountants of Ontario in 2003.

Board/Committee Membership:	**2007 Attendance:**	
Board (since December 2005)	10 of 11	91%
Audit and Risk Committee (since February 2006)	4 of 4	100%
Investment Funds Oversight Committee* (since February 2007)	3 of 3	100%

* Chair of Committee

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Resolve Business Outsourcing Income Fund

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

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C. Ian Ross
Age: 65
Collingwood, Ontario, Canada

Ian Ross served at the Richard Ivey School of Business at the University of Western Ontario from 1997 to September 2003. Most recently he held the position of Senior Director, Administration in the Dean's Office, and was also Executive in Residence for the School's Institute for Entrepreneurship, Innovation and Growth. He has served as Governor and President and CEO of Ortech Corporation; Chairman, President and CEO of Provincial Papers Inc.; and President and CEO of Paperboard Industries Corp. Mr. Ross currently serves as a Director for a number of corporations including Menu Foods Income Trust, GrowthWorks Canadian Fund Ltd., PetValu Canada Inc., RuggedCom Ltd., ING Direct Asset Management Limited, eJust Systems (formerly Praeda Managements Systems) and the Nuclear Waste Management Organization (NWMO). He is also a member of the Law Society of Upper Canada.

Board/Committee Membership:	**2007 Attendance:**	
Board (since December 2003)	11 of 11	100%
Audit and Risk Committee (since November 2004)	4 of 4	100%
Governance and Nominating Committee (since August 2005)	3 of 3	100%
Major Projects Committee (since November 2004)	12 of 12	100%
Nuclear Generation Projects Committee (since November 2006)	5 of 5	100%

Principal Occupation: Chairman, GrowthWorks Canadian Fund Ltd.

Board Memberships for other Reporting Issuers: GrowthWorks Canadian Fund Ltd.
Menu Foods Income Trust
PetValu Canada Inc.
RuggedCom Ltd.
ING Direct Asset Management Limited

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

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Marie C. Rounding
Age: 60
Toronto, Ontario, Canada

Marie Rounding is Counsel at Gowling Lafleur Henderson LLP where she is a member of the National Energy and Infrastructure Industry Group. On November 1, 2007, she was appointed by Prime Minister Stephen Harper to the Advisory Council on National Security. Ms. Rounding served as Chair of the Ontario Energy Board from 1992 to 1998 and as President and Chief Executive Officer of the Canadian Gas Association from 1998 to 2003. Prior to those appointments she was Director of the Crown Law Office, Civil Law at the Ontario Ministry of the Attorney General. She has extensive background in regulatory and administrative law, and as a leading regulator was involved in the deregulation of the natural gas markets and the early restructuring of the electricity sector in Ontario. Ms. Rounding currently serves as a Director for Nova Scotia Power Inc. and as a member of the Independent Review Committee for Sentry Select Capital Corp. and several related entities. She is a graduate of the University of Western Ontario and Osgoode Hall Law School and is certified by the Institute of Corporate Directors.

Board/Committee Membership:	**2007 Attendance:**	
Board (since September 2004)	11 of 11	100%
Compensation and Human Resources Committee (November 2004 – February 2007)	1 of 1	100%
Investment Funds Oversight Committee (since May 2005)	3 of 3	100%
Major Projects Committee (since November 2004)	9 of 12	75%
Nuclear Operation Committee (since February 2007)	3 of 3	100%

Principal Occupation: Counsel, Gowling Lafleur Henderson LLP

Board Memberships for other Reporting Issuers: Nova Scotia Power Inc.

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

William Sheffield
Age: 59
Toronto, Ontario, Canada

William Sheffield is the former Chief Executive Officer of Sappi Fine Paper plc., and a former Executive Vice President of International Operations and Corporate Development at Abitibi Consolidated. He has experience in operating large international industries. He also spent 17 years with Stelco. Mr. Sheffield currently serves on the Boards of Velan Inc., Canada Post, Houston Wire & Cable Company and Corby Distilleries. Mr. Sheffield has a B.Sc. in Chemistry from Carleton University, an M.B.A. from McMaster University and completed the Advanced Management Program at INSEAD School of Business, France and is certified by the Institute of Corporate Directors.

Board/Committee Membership:	**2007 Attendance:**	
Board (since September 2004)	11 of 11	100%
Compensation and Human Resources Committee* (since November 2004)	11 of 11	100%
Investment Funds Oversight Committee (since February 2005)	3 of 3	100%
Major Projects Committee (since November 2004)	12 of 12	100%

* Chair of Committee

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Corby Distilleries Ltd.
Houston Wire & Cable Company
Velan Inc.

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

David G. Unruh
Age: 63
Vancouver, British Columbia, Canada

David Unruh is a retired lawyer and general counsel currently serving as a director of Union Gas Limited, Pacific Northern Gas Ltd., Corriente Resources Inc., The Wawanesa Mutual Insurance Company, TransLink, Canada Line Rapid Transit Inc., and Globe Foundation of Canada. Prior to this, Mr. Unruh served as Vice Chairman of Westcoast Energy Inc. and Union Gas Limited, before that as Senior Vice President and General Counsel for Houston based Duke Energy Gas Transmission and, before that as Senior Vice President, Law and Corporate Secretary of Westcoast Energy Inc. Mr. Unruh practiced corporate and commercial law in Winnipeg, Manitoba before joining Westcoast Energy Inc. in Vancouver, British Columbia in 1993.

Board/Committee Membership:	**2007 Attendance:**	
Board (since September 2004)	11 of 11	100%
Compensation and Human Resources Committee (since November 2004)	11 of 11	100%
Audit/Risk Committee (since November 2004)	4 of 4	100%
Major Projects Committee (since December 2004)	12 of 12	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Corriente Resources Inc.
Pacific Northern Gas Ltd.
Union Gas Limited

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Orientation and Continuing Education

The Governance and Nominating Committee is responsible for reviewing and recommending appropriate orientation and education programs to the Board. New directors are provided relevant documentation relating to OPG's governance practices, policies and to its business. Directors attend comprehensive introductory briefing sessions from senior executives on OPG's operations and business and plant tours are provided to OPG generating facilities.

The Board supports the continuing education of directors, in both the business of OPG and their duties as directors. Annual plant tours of major facilities and, based on requests from directors, special presentations by internal and external experts are made to the Board or a Committee on topical business-related issues or on specific aspects of OPG's operations. OPG also sponsors the professional certification of its directors.

Ethical Business Conduct

OPG has a policy for ethical business behaviour and a Code of Business Conduct, which is approved by the Board. The Audit/Risk Committee Charter expressly includes regular reporting by Management on the Code of Business Conduct, including reports on substantiated cases of fraud and the disposition of such cases including disciplinary action. The Audit/Risk Committee also receives an annual report on the Code of Business Conduct in order to satisfy itself that appropriate codes of conduct and compliance programs are in place and are being enforced and remedial action is being taken. A copy of OPG's Code of Business Conduct has been filed on SEDAR (www.sedar.com). The Audit/Risk Committee has also established procedures for the receipt, retention and treatment of complaints received pertaining to internal accounting controls or auditing matters and the confidential anonymous submission by employees concerning such matters.

The Board has adopted an annual process of written disclosure by directors of information in order to: (i) identify potential conflicts of interest for the purposes of complying with the Ontario Business Corporations Act, (ii) validate their independence and financial literacy for the purposes of complying with securities regulations related to Boards and Audit Committees, and (iii) satisfy other disclosures and filings.

Nomination of Directors

The Governance and Nominating Committee's responsibilities are to: (i) develop and maintain a list of optimum skills which the Board should collectively possess, (ii) recommend a process to identify director candidates, (iii) recommend selection criteria, (iv) identify director candidates to the Board and (v) recommend to the Board the candidates to stand for election. The Board submits recommended candidates to the Shareholder. Nominations of directors by the Shareholder are also reviewed by the Governance and Nominating Committee.

The Governance and Nominating Committee consists of four members, three of which are independent of OPG within the meaning of MI 52-110. Dr. Gary Kugler is Chair of the Nuclear Waste Management Organization, an organization which is in effect controlled by OPG by virtue of OPG's proportionately larger financial responsibility for nuclear fuel. The Board of Directors determined that Dr. Kugler's service as Chair does not affect his ability to exercise impartial judgment and fulfill his responsibilities as a member of the Governance and Nominating Committee.

The Board consists of 12 directors.

Compensation

Director Compensation

The Governance and Nominating Committee is responsible for annually monitoring and reviewing the level and nature of compensation of directors. In 2007, the Governance and Nominating Committee recommended that no change be made to the compensation of directors.

Each director who is not an employee of OPG receives an annual retainer of $25,000. Directors also receive a $3,000 annual retainer to chair committees and for each committee that they are a member of. In recognition of the increased duties and responsibilities placed upon the chair of the Audit/Risk Committee as a result of recent regulatory initiatives in North America, the annual retainer for the Audit/Risk Committee chair is $8,000.

Directors are compensated for each meeting that they attend and receive a fee of $1,500 or $750, as determined by the Board or Committee chair.

In order to retain national and international expertise, non-resident directors are compensated in U.S. dollars exchanged at par and directors who travel long distances receive a travel fee to cover travel time related to Board and Committee meetings they attend.

Directors are also reimbursed for travel and other expenses they incur to attend meetings or to perform other duties in their role as a director.

The Chair of the Board in his role as non-executive Chair receives an all-inclusive annual fee of $150,000 and is reimbursed for out-of-pocket expenses including travel and other expenses.

The total compensation paid to the Directors of the Company for the year ended December 31, 2007 was $909,511.

CEO Compensation

The Compensation and Human Resources Committee of the Board consists of four directors, all of whom are independent of OPG. The Committee oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Compensation and Human Resources Committee seeks input from an independent advisor with regard to monitoring and benchmarking compensation developments.

During 2007, the Compensation and Human Resources Committee of the Board retained an independent advisor from Mercer Human Resource Consulting, to benchmark the compensation package for the President and CEO and to confirm that the compensation package is appropriate given the nature, complexity and risk profile of OPG's business. The Compensation and Human Resources Committee submitted its recommendation to the Board for approval. The Chair of the Compensation and Human Resource Committee and the Board Chair subsequently informed the Shareholder.

Board Committees

The Board has established seven committees to focus on areas critical to the Company:

Audit/Risk Committee

The Committee is responsible for reviewing the Company's regulatory filings including financial statements, MD&A, and press releases prior to their disclosures to the public. The Committee is also responsible for overseeing the internal audit function, the work of external auditors including their nomination and compensation, that the Company has adequate controls in the financial reporting process and the risk management process, and is in compliance with regulatory and internal policies. The Committee is also responsible for overseeing OPG's policy on ethical behaviour and the Code of Business Conduct, including reports on compliance programs, substantiated cases of fraud and the disposition of such cases including disciplinary action.

Compensation and Human Resources Committee

This Committee focuses on human resources related areas including compensation practices, CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review including succession planning, human resources policies related to employee complaints, diversity and pay equity, organizational design, labour relations, pension plans and policies, and Board compensation, education and evaluation programs.

Governance and Nominating Committee

The Committee develops governance principles for OPG that are consistent with high standards of corporate governance and reviewing and assessing on an ongoing basis OPG's system of corporate governance with a view to maintaining these high standards. The Committee identifies and recommends candidates for election or appointment to the Board to be put before the Shareholder in the event of a vacancy on the Board. Finally, the Committee reviews and recommends OPG's processes for director orientation, assessment, and compensation.

Investment Funds Oversight Committee

This Committee assists the Board in fulfilling its responsibilities for the OPG Pension Fund, the Used Fuel Fund and Decommissioning Fund. The Committee provides oversight of the investment of assets, investment-related liabilities and the management of any surplus (deficit) of the funds. Specifically the Committee: reviews the investment policies, risks and the asset mix; approves annual performance objectives for the investment portfolios; and monitors the performance of the funds.

Major Projects Committee

This Committee assists the Board in providing oversight of major non-nuclear electricity supply projects, including project development, contracting, financing, and construction monitoring.

Nuclear Generation Projects Committee

This Committee was formed in 2006 following direction from the Shareholder to: (i) begin feasibility studies on refurbishing its existing nuclear units, and (ii) to begin a federal approvals process, including an environmental assessment, for new nuclear units at an existing site. This Committee assists the

Board in providing oversight of the new nuclear plant projects and the refurbishment and life extension projects for existing nuclear plants.

Nuclear Operations Committee

This Committee is responsible for oversight of safe and efficient operations of OPG's nuclear business, regulatory compliance of OPG's nuclear facilities, review of reports from independent oversight of OPG's nuclear operations, reviews of OPG's nuclear management and organization matters, security of OPG's nuclear facilities and substances, and oversight of OPG's nuclear waste and decommissioning liabilities and management.

Assessments

The Governance and Nominating Committee is responsible for the annual process for evaluating the performance of the Board, its Committees and its individual directors. The Board and Committee evaluations are based upon the completion of confidential questionnaires regarding assessment of its performance and the compliance with the Board and Committee Charters. Director evaluations are based on self-assessment questionnaires, which are submitted in confidence to the Board Chair and the Chair of the Governance and Nominating Committee. The annual process is overseen by the Chair of the Governance and Nominating Committee, who reports the results and recommendations for enhancing oversight to the Board.

Further Information on OPG Governance

OPG provides additional information on OPG's governance on its website (www.opg.com) including:

- Memorandum of Agreement
- Shareholder Directives
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Code of Business Conduct
- Disclosure Policy
- Environment Policy
- Health and Safety Policy

AUDIT/RISK COMMITTEE INFORMATION

MI 52-110, Audit Committees, has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective and independent audit committees, which enhance the quality of financial disclosure and ultimately foster increased investor confidence in Canada's capital markets. Information on OPG's Audit/Risk Committee, which includes the text of the Audit/Risk Committee Charter, is as follows:

Audit/Risk Committee Charter

Purpose

The purpose of the Audit/Risk Committee (the "Committee") is to assist the Board in fulfilling its oversight responsibilities by reviewing, advising and making recommendations to the Board on:

- The integrity, quality and transparency of the Company's financial information,
- The adequacy of the financial reporting process,
- The systems of internal controls and risk management, and the Company's related principles, policies and procedures which Management have established,
- The performance of the Company's internal audit function and the external auditors,
- The external auditors' qualifications and independence,

- The Company's compliance with related legal and regulatory requirements and internal policies, and
- The promotion of a culture of ethical business conduct and compliance with OPG's Code of Business Conduct.

The function of the Audit/Risk Committee is oversight. Management is responsible for the preparation, presentation and integrity of the consolidated financial statements of the Company. Management of the Company is responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations.

Organization

Members

The Audit/Risk Committee shall consist of three or more independent Directors appointed by the Board of Directors, none of whom shall be employees of the Company or any of the Company's affiliates. A majority of the members of the Committee, but not less than two, will constitute a quorum. As a venture issuer, OPG is exempt from the statutory requirements of Multilateral Instrument 52-110 requiring members of Audit Committees to be independent. However, OPG considers such independence to be "best practice" and, therefore, each of the members of the Audit/Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing Audit Committees.

The Board of Directors shall designate one member of the Audit/Risk Committee as the Committee Chair. Members of the Audit/Risk Committee shall serve at the pleasure of the Board of Directors for such term or terms as the Board of Directors may determine. The Board of Directors shall confirm that each member of the Audit/Risk Committee is financially literate as such qualification is interpreted by the Board of Directors in its business judgment and in compliance with Multilateral Instrument 52-110 and its Companion Policy.

Meetings

The Committee will meet at least quarterly or more frequently as circumstances require and at any time at the request of a member. The Committee will meet regularly and at least annually with the external auditors, the internal auditors and Management in separate sessions to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in the Company's financial information or regulatory filings any report from the Audit/Risk Committee required by applicable laws and regulations and stating among other things whether the Audit/Risk Committee has:

- Reviewed and discussed the audited consolidated financial statements with Management,
- Discussed pertinent matters with the internal and external auditors,
- Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence, and
- Recommended to the Board of Directors that the audited consolidated financial statements be included in the Company's Annual Report.

Authority

While the Audit/Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit/Risk Committee to plan or conduct audits or risk assessments, or to determine that the Company's consolidated financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and the external auditor.

In carrying out its oversight responsibilities, the Audit/Risk Committee and the Board will necessarily rely on the expertise, knowledge and integrity of the Company's Management, and internal and external auditors.

The Audit/Risk Committee shall have the authority to set and pay the compensation for any advisors employed by the Committee.

The Audit/Risk Committee shall have the authority to communicate directly with the internal and external auditors.

Delegation of Authority

The Committee may delegate to any employee of OPG or a sub-committee the authority to: (i) execute or carry out any decision of the Committee; and/or (ii) exercise any right, power or function of the Committee on such terms and conditions and within such limits as the Committee may establish, except that the Committee may not delegate its oversight responsibilities.

Access to Management and Outside Advisors

The Audit/Risk Committee shall have unrestricted access to members of Management and relevant information. The Audit/Risk Committee may retain independent counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

Committee Responsibilities and Duties

The Committee shall:

General

- Conduct or authorize investigations into any matters within the Committee's scope of responsibilities, and
- Review and recommend approval to the Board, the appointment or replacement of the CFO and the CRO.

Risk Management and Internal Controls

- Review and evaluate the Company's policies and processes for assessing significant risks or exposures and the steps Management has taken to monitor and control such risks to the Company, including the organizational structure and the adequacy of resources,
- Consider and review with the CRO and Management the critical risks to the Company, the potential impact of such risks, and related mitigation,
- Ascertain whether the Company has an effective process for determining risks and exposure from actual and potential litigation and claims relating to non-compliance with laws and regulations,
- Review with Management, reports demonstrating compliance with risk management policies,
- Review with the Company's General Counsel and others any legal, tax, or regulatory matters that may have a material impact on Company operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty,
- Review with Management, internal audit, and the external auditors, the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls,
- Review disclosures made by the CEO and CFO during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in the Company's internal controls, and
- Review the expenses of the Chairman, Board, President and the President's direct reports on a semi-annual basis, and of any other senior officers and employees the Committee considers appropriate.

Internal Audit

- Evaluate the internal audit process and define expectations in establishing the annual internal audit plan and the focus on risk, including the organizational structure and the adequacy of resources,
- Approve the Charter of the internal audit function annually,
- Evaluate the audit scope and role of internal audit, and
- Consider and review with the CRO and Management:
  - Significant findings and Management's response including the timetable for implementation of Management Actions to correct weaknesses,
  - Any difficulties encountered in the course of their audit (such as restrictions on the scope of their work or access to information),
  - Any changes required in the planned scope of the audit plan, and
  - The internal audit budget.

External Auditor

- Recommend to the Board of Directors the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, and the compensation of the external auditor,
- Oversee the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, including the resolution of disagreements between Management and the external auditor regarding financial reporting,
- Review the independence and qualifications of the external auditor,
- At least annually, obtain and review a report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and the Company,
- Review the scope and approach of the annual audit plan with the external auditors,
- Discuss with the external auditor the quality and acceptability of the Company's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management,
- Assess the external auditor's process for identifying and responding to key audit and internal control risks,
- Ensure the rotation of the lead audit partner every five years and other audit partners every seven years, and consider regular rotation of the audit firm,
- Evaluate the performance of the external auditor annually and present its findings to the Board of Directors,
- Determine which non-audit services the external auditor is prohibited by law or regulation, or as determined by the Audit/Risk Committee, from providing and pre-approve all services provided by the external auditors. The Committee may delegate such pre-approval authority to a member of the Committee. The decision of any Committee member to whom pre-approval authority is delegated must be presented to the full Audit/Risk Committee at its next scheduled meeting,
- Review and approve all related party transactions, and
- Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company.

Financial Reporting

- Review with Management and the external auditors the Company's interim financial information and disclosures under MD&A and earnings press release, prior to filing,
- Satisfy itself that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's consolidated financial statements, other than the public disclosure referred to above, and periodically assess the adequacy of those procedures,

- Review with Management and the external auditors, at the completion of the annual audit:
  - The Company's annual financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by the Company or that the Company otherwise files with the OSC,
  - The external auditors' audit of the consolidated financial statements and their report,
  - Any significant changes required in the external auditors' audit plan,
  - Any difficulties or disputes with Management encountered during the audit,
  - The Company's accounting principles, and
  - Other matters related to conduct, which should be communicated to the Committee under generally accepted auditing standards.
- Review significant accounting and reporting issues and understand their impact on the consolidated financial statements. These include complex or unusual transactions and highly judgmental areas; major issues regarding accounting principles and financial presentations, including significant changes in the Company's selection or application of accounting principles; and the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements, on the consolidated financial statements of the Company,
- Review analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative Generally Accepted Accounting Principles methods, and
- Advise Management, based upon the Audit/Risk Committee's review and discussion, whether anything has come to the Committee's attention that causes it to believe that the consolidated financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

<u>Compliance with Code of Business Conduct</u>

- Review the administration of and compliance with the Company's Code of Business Conduct to ensure that appropriate codes of conduct and compliance programs are in place, are being enforced and remedial action is being taken, as well as the process for communicating the Code of Business Conduct to Company personnel, and
- Monitor through regular updates from Management regarding compliance matters.

<u>Treatment of Complaints</u>

- Establish procedures for the receipt, recording and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters, and
- Establish procedures for the confidential and anonymous submission by employees of concerns regarding accounting or auditing matters of the Company.

Annual Review and Assessment

The Committee shall conduct an annual review and assessment of its performance, including a review of its compliance with this Charter, in accordance with the evaluation process approved by the Board.

The Committee shall also review and assess the adequacy of this Charter on an annual basis taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship, and if appropriate, shall recommend changes to the Board.

Composition of the Audit/Risk Committee

OPG's Audit/Risk Committee consists of George Lewis, Gary Kugler, Peggy Mulligan, Ian Ross and David Unruh. As a venture issuer, OPG is not subject to the rules governing the composition and independence of audit committees which are established by MI 52-110. However, OPG's Board of Directors has determined to follow best practices and constitute the Audit/Risk Committee in accordance with the requirements of MI 52-110. The Board of Directors has concluded that all of the members of the committee are financially literate, within the meaning of MI 52-110. In addition, the Board of Directors has concluded that four of the five members of the Committee are independent of OPG and its subsidiaries within the meaning of MI 52-110. At the request of the Board of Directors, Dr. Kugler serves as a Director and Chairman of the Nuclear Waste Management Organization, an organization which is in effect controlled by OPG by virtue of OPG's proportionately larger financial responsibility for nuclear fuel. The Board of Directors believes that Dr. Kugler's service as Chairman is in the best interests of OPG, the NWMO, and OPG's stakeholders, in view of his experience and extensive knowledge of the Canadian nuclear industry, and does not affect his ability to exercise impartial judgment and fulfill his responsibilities as a member of the OPG Audit/Risk Committee. In view of OPG's nuclear operations and related financial and waste management obligations, Dr. Kugler's experience and knowledge is also considered a key input to the planning and risk management components of the Committee's mandate. As a result, OPG's Board of Directors has determined that it is appropriate for Dr. Kugler to serve as a non-independent member of that Committee, in accordance with section 3.3(2) of MI 52-110.

Relevant Education and Experience

Financially literate means having the ability to read and understand the accounting principles used by OPG to prepare its consolidated financial statements, and the ability to address the breadth and level of complex accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by OPG's consolidated financial statements. Each member had an understanding of internal controls and procedures for financial reporting. The education and experience of each Audit/Risk Committee member that are relevant to his or her performance as an audit committee member may be found in the *Corporate Governance* section.

Audit/Risk Committee Oversight

There have been no recommendations of the Audit/Risk Committee to nominate or compensate an external auditor which have not been adopted by the Board of Directors.

External Auditor Service Fees

The following fees were billed by Ernst & Young LLP:

(thousands of dollars)	**2007**	**2006**
Audit Fees	**1,253**	1,250
Audit-Related Fees	**259**	335
Tax Fees and Other	**118**	300

Audit Fees

These fees included the audit of OPG's consolidated financial statements, quarterly reviews of the financial statements, and the pension fund audits.

Audit-Related Fees

These fees included work with respect to internal controls, accounting assistance, French translation of consolidated financial statements and MD&A, and special audits and reviews. During 2007, OPG has employed the services of other professional advisers, particularly in the areas of internal controls and accounting assistance.

Tax Fees and Other

These fees included tax services related to assistance with matters raised by the Tax Auditors for the 1999 taxation year and a United States state tax review.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and CEO and Chief Financial Officer (CFO), are responsible for maintaining disclosure controls and procedures and internal control over financial reporting. Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with GAAP.

An evaluation of the effectiveness of design and operation of OPG's disclosure controls and procedures was conducted as of December 31, 2007. Management, including the President and the CEO and the CFO, has evaluated the effectiveness of OPG's disclosure controls and procedures (as defined in Multilateral Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*, of the Canadian Securities Administrators) as of December 31, 2007. Management has concluded that, as of December 31, 2007, OPG's disclosure controls and procedures were effective to provide reasonable assurance that material information relating to OPG and its consolidated subsidiaries and interests in jointly controlled entities would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

Management has designed internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and has concluded, as of December 31, 2007, that the design of internal controls over financial reporting was effective.

There were no material changes in internal control over financial reporting in OPG's most recent interim period that have materially affected or are reasonably likely to materially affect OPG's internal control over financial reporting.

FOURTH QUARTER

Overview of Results

Net income for the three months ended December 31, 2007 was $119 million compared to a net loss of $19 million for the same period in 2006. Loss before income taxes for the three months ended December 31, 2007 was $44 million compared to loss before income taxes of $82 million for the same period in 2006.

During the fourth quarter of 2007, there was a net income tax recovery of $163 million, compared to $63 million for the same period in 2006. The increase in income tax recoverable was largely due to the additional contribution to the Used Fuel Fund of $334 million during the fourth quarter of 2007. In addition, the income tax expense was favourably impacted by a reduction in federal future income tax rates that were substantively enacted during the fourth quarter of 2007.

The following is a summary of the factors impacting OPG's results for the three months ended December 31, 2007 compared to results for the same period in 2006, on a before-tax basis:

(millions of dollars – before tax) (unaudited)	
Loss before income taxes for the three months ended December 31, 2006	**(82)**
Changes in gross margin	
Increase in electricity sales price after revenue limit rebate and hedging margin	13
Change in electricity generation by segment:	
Regulated – Nuclear	31
Regulated – Hydroelectric	(9)
Unregulated – Hydroelectric	(29)
Unregulated – Fossil-Fuelled	3
Increase in revenue due to the Lennox Reliability Must Run contract	14
Other changes in gross margin	2
	25
Increase in amortization of the Pickering A return to service deferral account balance	(16)
Decrease in earnings on nuclear fixed assets removal and nuclear waste management funds	(8)
Other changes	5
Increase in income before other gains and losses and income taxes	**6**
Impairment of long-lived assets – 2006	22
Other gains and losses – 2007	10
Loss before income taxes for the three months ended December 31, 2007	**(44)**

Earnings for the three months ended December 31, 2007 were favourably impacted by an increase in gross margin due primarily to higher generation from nuclear and fossil-fuelled generating stations and higher electricity prices net of revenue limit rebate. The gross margin was also favourably impacted by revenue from the Lennox RMR contract. In December 2007, the OEB approved a third one-year term contract, which ends September 30, 2008. The increase in gross margin was partially offset by lower generation from OPG's hydroelectric facilities.

The demolition of the former Lakeview coal-fired generating station was substantially completed during 2007. During the fourth quarter of 2007, the Company re-estimated the costs to complete the remaining work to remediate the site in 2008. As a result, OPG recorded a recovery of $20 million in other gains and losses to reflect a change in the estimated costs.

During the fourth quarter of 2007, OPG recorded impairment losses of $10 million in other gains and losses related to the fair market value of its third-party ABCP holdings.

During the fourth quarter of 2006, OPG recognized an impairment loss of $22 million on the Thunder Bay and Atikokan coal-fired generating stations, which represented the carrying amount or net book value of these stations. The impairment charge was recorded in other gains and losses.

Discussion of Operating Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2007	2006
Revenue, net of revenue limit rebate	**1,342**	1,276
Fuel expense	**308**	267
Gross margin	**1,034**	1,009
Operations, maintenance and administration	**815**	806
Depreciation and amortization	**176**	164
Accretion on fixed asset removal and nuclear waste management liabilities	**126**	124
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(89)**	(97)
Property and capital taxes	**19**	24
(Loss) income before other gains and losses, interest and income taxes	**(13)**	(12)
Other (gains) and losses	**(10)**	22
Loss before interest and income taxes	**(3)**	(34)

Revenue

(millions of dollars) (unaudited)	Three Months Ended December 31 2007	2006
Regulated generation sales [1]	**681**	665
Spot market sales, net of hedging instruments	**519**	453
Revenue limit rebate	**(51)**	(13)
Variance accounts	**7**	(4)
Other	**186**	175
Total revenue	**1,342**	1,276

[1] Regulated generation sales included revenue of $31 million and $46 million that OPG received at the Ontario electricity spot market price for Regulated – Hydroelectric generation over 1,900 MWh in any hour during the fourth quarter of 2007 and 2006, respectively.

Revenue

Revenue was $1,342 million for the three months ended December 31, 2007 compared to $1,276 million during the same period in 2006. The increase of $66 million was primarily due to a higher electricity sales price, net of revenue limit rebate, and increased generation volume.

Electricity Prices

OPG's average sales price for the three months ended December 31, 2007 was 4.6¢/kWh compared to 4.5¢/kWh for the same period in 2006. The increase was primarily due to a higher revenue limit for electricity generation from OPG's unregulated facilities and a higher average hourly Ontario spot electricity market price during the fourth quarter of 2007 compared to the same quarter in 2006.

Fuel Expense

Fuel expense was $308 million for the three months ended December 31, 2007 compared to $267 million during the same period in 2006. The increase of $41 million was primarily due to higher generation of 1.0 TWh from OPG's fossil-fuelled generating stations.

Operations, Maintenance and Administration

OM&A expenses for the three months ended December 31, 2007 were $815 million compared to $806 million during the same period in 2006. The increase in OM&A expenses was primarily due to higher OM&A expense related to the Unregulated – Fossil-Fuelled segment in the fourth quarter of 2007.

Earnings on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Earnings on the Nuclear Funds during the fourth quarter of 2007 were $89 million compared to $97 million for the same period in 2006. The decrease in earnings of $8 million was primarily due to additional earnings recorded in 2006 as a result of the revision to the ONFA reference plan, which did not recur in 2007, and a lower long-term target rate of return on the Decommissioning Fund as specified in the 2006 ONFA Approved Reference Plan. The decrease in earnings was partially offset by the impact of higher Nuclear Fund investments and a higher Ontario CPI in the fourth quarter of 2007 compared to the same quarter in 2006.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable business segment, net of the revenue limit rebate for the three months ended December 31, 2007 and 2006, were as follows:

	Three Months Ended December 31	
(¢/kWh)	**2007**	**2006**
Weighted average hourly Ontario spot electricity market price	**5.1**	4.5
Regulated – Nuclear	**4.9**	4.9
Regulated – Hydroelectric	**3.5**	3.5
Unregulated – Hydroelectric	**4.7**	4.5
Unregulated – Fossil-Fuelled	**4.8**	4.6
OPG's average sales price	**4.6**	4.5

As a result of regulated prices and the revenue limit rebate, OPG's average sales price was lower than the weighted average hourly Ontario spot electricity market price.

Electricity Generation

Total electricity sales volume for the three months ended December 31, 2007 was 24.7 TWh compared to 24.3 TWh during the same period in 2006. The increase was primarily due to higher generation from OPG's fossil-fuelled and nuclear generating stations, partially offset by lower generation from OPG's hydroelectric facilities. The higher generation from OPG's nuclear generating stations for the three months ended December 31, 2007 compared to the same period in 2006 was primarily due to lower outage days. The lower electricity sales volume from OPG's hydroelectric facilities during the fourth quarter of 2007 compared to the same quarter in 2006 was primarily due to lower water levels in Eastern Ontario.

During the fourth quarter of 2007 and 2006, the primary electricity demand in Ontario was 37.7 TWh and 37.5 TWh, respectively. The higher primary demand in Ontario during the fourth quarter of 2007 was in part due to colder temperatures in November and December of 2007 compared to the same months in 2006.

Liquidity and Capital Resources

Cash flow used in operating activities during the three months ended December 31, 2007 was $316 million compared to cash flow provided by operating activities of $91 million for the three months ended December 31, 2006. The unfavourable change in cash flow was primarily due to the one-time contribution of $334 million to the Used Fuel Fund related to the Bruce Lease and higher operating and maintenance expenditures.

Investment in fixed assets during the three months ended December 31, 2007 was $190 million compared with $215 million during the same period in 2006. The decrease in capital expenditures of $25 million was primarily due to lower expenditures for the Niagara Tunnel project.

Cash flow provided by financing activities during the three months ended December 31, 2007 was $449 million compared to cash flow used in financing activities of $45 million for the three months ended December 31, 2006. The increase in cash flow was primarily due to the issuance of long-term debt under the general corporate facilities of $400 million in the fourth quarter of 2007.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the twelve most recently completed quarters. This financial information has been prepared in accordance with Canadian GAAP.

	2007 Quarters Ended				
(millions of dollars) (unaudited)	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Revenue, net of revenue limit rebate	**1,342**	**1,421**	**1,373**	**1,524**	**5,660**
Net income	**119**	**113**	**125**	**171**	**528**
Net income per share	**$0.46**	**$0.44**	**$0.49**	**$0.67**	**$2.06**

	2006 Quarters Ended				
(millions of dollars) (unaudited)	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Revenue, net of revenue limit rebate	1,276	1,435	1,345	1,508	5,564
Net (loss) income	(19)	167	143	199	490
Net (loss) income per share	$(0.08)	$0.65	$0.56	$0.78	$1.91

	2005 Quarters Ended				
(millions of dollars) (unaudited)	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	1,496	1,571	1,373	1,358	5,798
Income (loss) before extraordinary item	160	181	137	(38)	440
Income (loss) before extraordinary item per share	$0.62	$0.71	$0.53	$(0.15)	$1.71
Net income (loss)	160	181	63	(38)	366
Net income (loss) per share	$0.62	$0.71	$0.25	$(0.15)	$1.43

Balance Sheet as at December 31

(millions of dollars)	**2007**	**2006**	**2005**
Total assets	**24,839**	22,750	21,623
Total long-term liabilities	**16,494**	15,408	13,640
Cash dividend declared per share *(dollars)*	**-**	$0.50	-
Common shares outstanding *(millions)*	**256.3**	256.3	256.3

OPG's quarterly results are impacted by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter.

Additional items which impacted net income (loss) in certain quarters above include the following:

- Lower OM&A expenses due to the deferral of non-capital costs related to the planned return to service of all units at the Pickering A nuclear generating station, beginning January 1, 2005, as required by a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario);
- Impairment loss on the Lennox generating station of $202 million recorded during the first quarter of 2005, reflecting the amount of the carrying value of the station;
- Lower income tax expense due to the use of the taxes payable method for the regulated segments commencing April 1, 2005;
- Impairment loss of $63 million related to Units 2 and 3 of the Pickering A nuclear generating station, recorded in the second quarter of 2005;
- One-time extraordinary loss of $74 million recorded in the second quarter of 2005, resulting from the adoption of rate-regulated accounting and the corresponding use of the taxes payable method;
- Write-off of $22 million and $35 million of excess inventory as a result of not returning Pickering A nuclear generating station Units 2 and 3 to service, recorded in the third and fourth quarters of 2005 respectively;
- Higher depreciation expense related to the return to service of Unit 1 at the Pickering A generating station in the fourth quarter of 2005;
- Decrease in depreciation expense primarily due to the extension of service lives, for accounting purposes, of the Nanticoke generating station, Pickering B generating station and Unit 4 of the Pickering A generating station beginning in the first quarter of 2006;
- Higher pension and OPEB costs during 2006 and 2007 compared to 2005 mainly due to changes in economic assumptions used to measure the costs;
- Write-off of $13 million for costs incurred on the Thunder Bay conversion project due to a Shareholder Declaration that effectively cancelled the project during the second quarter of 2006;
- Decrease in depreciation expense primarily due to extension of the service life, for accounting purposes, of all coal-fired generating stations to December 31, 2012, beginning in the third quarter of 2006;
- Impairment loss on the Thunder Bay and Atikokan coal-fired generating stations of $22 million, reflecting the carrying value of the stations, during the fourth quarter of 2006;
- Higher OM&A expense in 2007 primarily due to higher outage and other maintenance expenditures at OPG's nuclear and fossil-fuelled generating stations, and expenses related to past grievances by First Nations;
- Decrease in gross margin from electricity sales during the first quarter of 2007 primarily due to lower generation from OPG's nuclear generating stations as a result of an unplanned outage during the first quarter of 2007 at the Pickering B nuclear generation station caused by an inadvertent release of resin by a third-party contractor from the water treatment plant into the demineralized water system, and the requirement for maintenance related to the recovery of the resin. In addition, nuclear generation was also impacted by an extension to a planned outage during the first quarter of 2007 at the Pickering A nuclear generating station for significant additional repair work required as a result of a component failure during inspection;
- Higher earnings from the Nuclear Funds during the second quarter of 2007 primarily due to a higher Ontario CPI during the second quarter of 2007, which impacted the guaranteed return on the Used

Fuel Fund. In addition, the increase in earnings also reflected a reimbursement from the Nuclear Funds for expenditures related to the safe storage of Pickering A Units 2 and 3; and

- Lower gross margin primarily due to lower nuclear generation during the three months ended September 30, 2007 as a result of the shutdown of the Pickering A nuclear generating station Units 1 and 4 to perform modifications on a backup electrical system.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, audited consolidated financial statements as at and for the years ended December 31, 2007 and 2006 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian GAAP and therefore may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements and notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) **Gross margin** is defined as revenue less revenue limit rebate and fuel expense.

(2) **Earnings** are defined as net income.

For further information, please contact:

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BUSINESS PLANNING AND BUDGETING PROCESS

1.0 PURPOSE

The purpose of this evidence is to present an overview of OPG business planning and budgeting process. This process applies to revenues and all expenditures, including capital, operating, and provision-funded expenditures.

2.0 BUSINESS PLANNING AND BUDGETING – PROCESS OVERVIEW

OPG's business planning and budgeting process is a largely decentralized annual process undertaken within a consistent corporate framework. The corporation establishes a consistent framework of corporate strategic objectives, resource guidelines, and costing assumptions. The key elements of this planning framework are identified to the business units through business planning instructions provided by the Financial Planning department in Corporate Finance. Individual business units develop their associated 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:

- Identification and confirmation of key strategic objectives and priorities by OPG's Senior Management and Board of Directors (see Ex. A1-T4-S1).

- 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.

- Development by OPG's Energy Markets group of the revenue and sales forecast, along with associated scenarios and sensitivities. This is based on key production inputs from the Nuclear and Hydroelectric business units, water levels, and plant/generation unit availability, including planned and forced outages.

- Identification of key risks to forecast results and mitigation initiatives, within a framework developed by OPG's Enterprise Risk Management program.

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

- Preparation of preliminary business plans by the business units.

- Preparation of a consolidated financial outlook by Corporate Finance, based on inputs received from across the organization. Financial Planning develops a comprehensive financial outlook by supplementing the business unit 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 forecasted in conjunction with the Corporate Taxation department.

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

- Financial Planning prepares overviews of the consolidated preliminary results based on the initial submissions, identifying key changes in the financial outlook and their underlying drivers.

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

- The draft consolidated business plan, based on updated November submissions, is reviewed by OPG senior management. The plan is also reviewed with shareholder representatives. The plan is then finalized for submission to the OPG Board of Directors in December for approval.

3.0 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 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. 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. This process may include incremental changes from the previous business plan and/or zero-based budgeting, depending on the business unit practices. Further details regarding business planning and budgeting processes within the business units are provided in Ex. A1-T4-S2 and A1-T4-S3.

The draft business unit business plans are reviewed by business unit management and adjustments are made as required. The respective draft business unit plans are finalized and each is presented to the CEO and Chief Financial Officer ("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 presented to the Board of Directors in December for approval. Once approved, the first year of the plan becomes the basis for operational and financial reporting for the budget year, and the balance of the years serve as a planning reference for the corporation.

4.0 INVESTMENTS/PROJECTS

Investments or projects in OPG are classified as capital or OM&A, or charged to provision funds (see Exhibit H). OPG applies the following principles as the basis for determining whether expenditures are classified as capital or OM&A. OPG's treatment is consistent with Generally Accepted Accounting Principles ("GAAP") and the Canadian Institute of Chartered Accountants ("CICA") Handbook.

4.1 Classification of Expenditures

Expenditures that are incurred by OPG are classified in accordance with Canadian GAAP as either capital or 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. H1-T1-S2).

Expenditures that are classified as capital are fixed assets. OPG capitalizes the following types of expenditures:

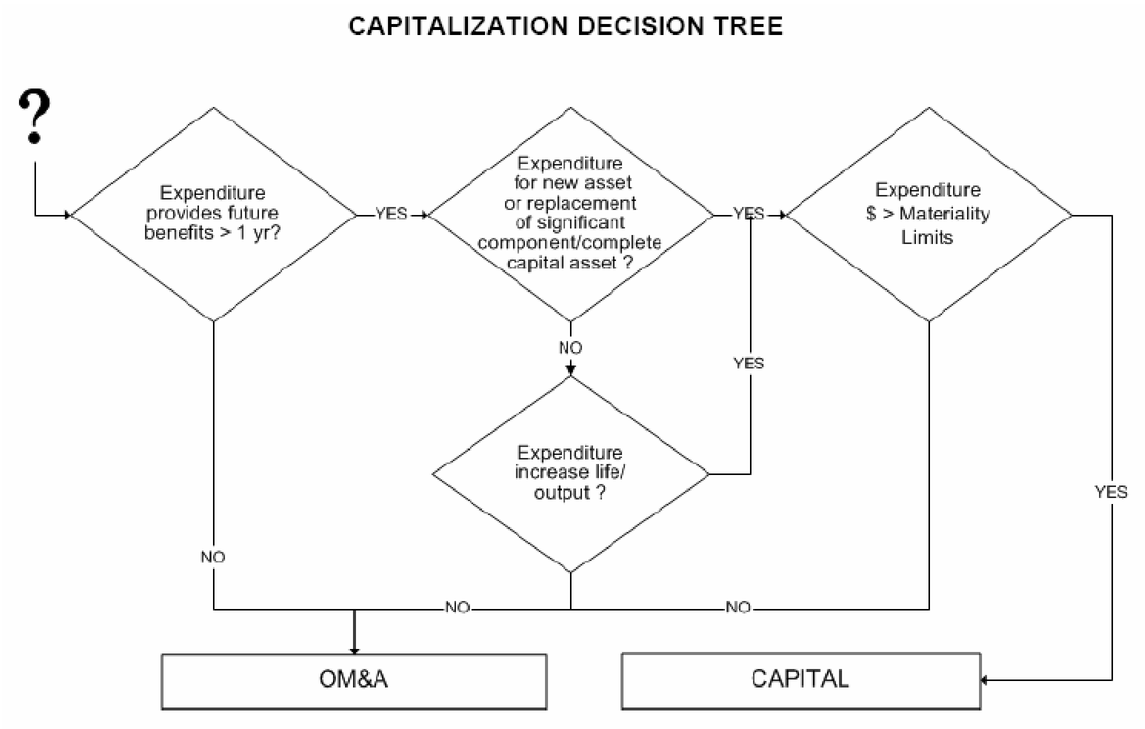
- Acquisition and construction of new assets: expenditures related to the purchase, design, development, construction or commissioning of a new asset which will provide benefits beyond the current year and meets or exceeds the defined materiality threshold are capitalized.

- Rehabilitation/Improvement/Maintenance of existing assets: expenditures related to existing assets must meet all of the following criteria to be capitalized:
  - Benefits extend beyond the current year.
  - Meets or exceeds the materiality threshold.
  - Either extends the life or increases 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.

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 to be eligible for capitalization and do not relate to previously established liabilities. In addition, project development costs incurred prior to the date of the selection of the alternative to implement 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:



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

• Generating Asset Classes	$200,000 per generating unit
• Administrative/Service Buildings	$ 25,000 per building
• Telecom Equipment	$ 25,000 per item
• Minor Fixed Assets*	$ 25,000 per item
• Software	$200,000 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.

It should be noted that the $25,000 materiality threshold for administrative/service buildings, telecom equipment and minor fixed assets became effective January 1, 2007. Thresholds were $10,000, $15,000, and $2,000, respectively, in 2005 and 2006. This change in accounting policy was applied prospectively to expenditures incurred in 2007. The change makes OPG's capitalization materiality thresholds more consistent with thresholds used by companies of similar size and avoids increases in administrative costs.

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.

4.2 Asset Management

OPG strives to continuously operate its diversified generation assets in a safe, efficient and cost effective manner, while undertaking prudent investments to improve their reliability and predictability. This involves asset management processes and practices to ensure asset related investments are consistent, cost-efficient, effective, and critical to achieving business objectives. These investments are designed to create shareholder value and to protect asset value over the planned life of the asset.

Specifically, OPG investment programs and initiatives are targeted at:

- Improving safety performance.
- Optimizing production.
- Replacing aging equipment.
- Automating obsolete control equipment.
- Reducing forced outages through improvements in plant condition and equipment reliability.
- Enhancing maintenance practices.
- Optimizing planned outages to improve availability.
- Reducing maintenance backlogs.
- Mitigating technological risks through comprehensive inspection and testing programs.
- Addressing resource (e.g., labour, equipment, and material) planning issues.
- Effectively managing costs with focus on production unit energy costs.

These programs 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 is also undertaking a number of new supply development initiatives. These development projects are typically larger in size and have higher risk profiles than other projects. As such, new supply development projects are subject to more rigorous internal scrutiny during the approval process and, often, external third party reviews, prior to the decision to proceed.

4.3 Project Portfolios and Supporting Documentation

In support of annual business plan reviews, business units submit project listings that have been prioritized to maximize value and address regulatory requirements while considering risks, corporate business objectives, asset management processes, and preliminary funding guidelines developed early in the business planning process. All projects necessary to meet work program requirements and having cash flows within the business plan time horizon are listed. The total cost for the projects listed must fall within the preliminary project and program budget totals in the corporate business planning guidelines.

The project listing is a snapshot of the project work intended to be done over the business plan horizon, at the time of listing. 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 exhibit.

4.3.1 <u>Planning Business Cases</u>

"Planning" business cases, or project screening forms in nuclear (beginning in 2007), are required for all 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, which will subsequently be required for project approval.

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:

- The need for the project.
- The project's contribution to meeting OPG's business objectives.
- Results to be delivered.
- Quantifiable benefits.
- Alternatives considered.
- 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.

4.3.2 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.

[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.

- Regulatory – Expenditures required to satisfy statutory environmental, safety or other legal requirements to assure continued operation of existing facilities.
- Sustaining – Required to maintain existing infrastructure and facilities at their current performance level.

4.3.3 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 applied to assist with selection of the highest priority projects which will remain within the funding guidelines and resource capabilities. Since business units manage different assets, prioritization schemes are also unique to each business unit. However, business unit prioritization schemes have common elements such as value, consideration of risks, and regulatory compliance underpinning their processes.

The businesses evaluate the need for each project against the business objectives, investment costs and benefits, and the risk of not conducting the work. This information is sometimes used to assist with prioritization and making investment trade-offs amongst business units.

5.0 BUSINESS CASE REQUIREMENTS FOR PROJECT RELEASE

Prior to beginning work on a project (development or execution related) approval is required for the release of funds to undertake the 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. The Organizational Authority Register provides a common framework of delegated authorities and position holders who can exercise those authorities, 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 Organizational Authority Register 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 the BCS to ensure that it meets the criteria for the quality and completeness of the information required to enable an informed decision to be made regarding approval of the project release.

The format of the BCS is in accordance with the OPG BCS Guidelines. This ensures consistent development and review of investment proposals.

Due diligence is exercised by the delegated authorities in conducting their review of the proposed investment. Depending on the dollar amount and strategic significance of the investment, review and sign-off at appropriate management and executive levels are required prior to all approvals.

Considerations during review and assessment of the proposal generally include the following:

- Priority of the proposed project relative to other projects in the submitted project portfolios in maximizing asset value.
- Alignment with business objectives and initiatives.
- Value contribution to the business.
- Interdependencies with other projects or outages.
- Level of definition of project scope and stage of development.
- Possible alternatives to the proposed alternative, including deferral.
- Validity of assumptions used in the evaluation of alternatives.
- Quality of the project cost estimates.
- Identification, assessment and mitigation of potential risks to ensure project success and management of risks.

- Proposals for measurement and verification of the claimed project benefits following project completion.

6.0 POST IMPLEMENTATION REVIEW PROCESS

The post implementation review ("PIR") process is used by OPG on a corporate-wide basis to gather additional information on achievements following completion of capital and OM&A projects. Specifically, a PIR is an objective appraisal process designed to assess 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.

<u>Simplified PIR:</u>

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

<u>Comprehensive PIR:</u>

A comprehensive PIR is an independent and broad, "cradle to grave" review of a completed project. It is an intensive exercise requiring an independent multi-disciplinary team to review all phases of a project from inception to benefit realization. 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. Hence, a rigorous screening process is applied to candidate projects to select the most appropriate and feasible projects for a comprehensive PIR.

In addition to validating the benefits realized, a comprehensive PIR examines the following three aspects of the project:

- Review of the project intent, plan, and execution for lessons learned and improvement opportunities.
- Evaluation of how project risks were mitigated relative to plan.
- Review of the business case for the project, assessing results to provide feedback for future decisions.

Annual and semi-annual PIR reports are prepared to provide a brief summary of key PIR findings and recommend additional management actions to improve the effectiveness of the PIR process.

RATING AGENCY REPORTS

1.0 PURPOSE

The purpose of this evidence is to provide rating agencies' financial assessments of OPG and highlight implications for OPG.

2.0 CREDIT RATINGS

OPG obtains its credit ratings from Standard & Poor's and Dominion Bond Rating Service. On an annual basis, OPG management meets with each agency to review actual results, corporate strategies, operational performance, and financial forecasts. The agencies each produce an annual credit report on OPG following their meetings and a specific long-term and short-term rating for OPG based on their respective rating scales. OPG provides the agencies with quarterly financial performance updates and on-going communication related to significant business issues that may arise during the year to the agencies.

The credit ratings incorporate many quantitative and qualitative considerations relating to OPG's management, strategy, operations, and financial performance over both the short and longer term. As with all credit ratings, for a rating change to occur, OPG must consistently demonstrate notable or trend improvements over a period of time.

The credit reports are used by the financial markets as an independent opinion of the general creditworthiness of OPG and its debt obligations outstanding. The reports are used by internal management as a benchmark comparison to the financial metrics of other companies in the same sector and as a guideline to address debt leverage and business issues that may affect OPG's rating. The cost and availability of liquidity under OPG's bank agreement is tied directly to the ratings provided by Dominion Bond Rating Service and Standard & Poor's. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets, conversely higher ratings result in lower borrowing costs and increased access to capital markets.

3.0 CREDIT RATING OVERVIEW

As at December 2007, OPG had a long-term credit rating of BBB+ by Standard & Poor's and A (low) by Dominion Bond Rating Service. In May 2006, Standard & Poor's upgraded the Company's short-term Canadian Scale Commercial Paper debt rating to A-1 (Low) from A-2. In November 2007, Dominion Bond Rating Service issued a rating report confirming OPG's long-term debt rating and short-term Commercial Paper rating of A (low) and R-1 (low), respectively. Copies of the most recent reports from Dominion Bond Rating Service and Standard & Poor's are provided in Attachments A, B and C.

In their report, Standard & Poor's highlights OPG's weaknesses as:

- Uncertain sales volumes due to seasonality of electricity demand, variability in both river flows, and asset operating performance.
- Below-average financial profile related to low allowed returns on regulated operations and an interim revenue cap on unregulated operations.
- Operational challenges at nuclear and coal-fired facilities.
- Significant risk exposure due to nuclear technology and potential for unexpected large capital expenditures.

LIST OF ATTACHMENTS

Rating Report

Report Date:
November 30, 2007

Previous Report:
August 3, 2006

Insight beyond the rating.

Ontario Power Generation Inc.

Analysts

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The Company

Ontario Power Generation Inc. is an electricity generating company with a diverse portfolio of 22,157 MW of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Recent Actions

August 28, 2007
Comments on ABCP Exposure

August 3, 2006
Ratings Confirmed

May 20, 2005
Long-Term Trend Changed to Stable from Under Review with Developing Implications

Authorized Commercial Paper Limit: $1 Billion

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debt*	A (low)	Confirmed	Stable

* Debt held by the Ontario Electric Finance Corporation (OEFC).

Rating Rationale

DBRS has confirmed the Unsecured Debt and Commercial Paper ratings of Ontario Power Generation Inc. (OPG or the Company) at A (low) and R-1 (low), respectively, with Stable trends. The rating confirmations reflect OPG's relatively modest level of business risk stemming from its regulated and non-regulated electric generation operations, stable financial profile underpinned by its robust balance sheet and credit metrics, as well as an improved regulatory environment. However, these factors are offset by the revenue limits on OPG's unregulated generation (which dampens financial performance), the general inability to pass through operating cost increases for both regulated and unregulated assets and by the higher expected capital expenditures that are likely to result in a modest decline in credit metrics. DBRS notes that the ratings on OPG continue to be supported by a sole shareholder, the Province of Ontario (the Province), which is rated AA. The Province supports OPG by providing all of its long-term funding; therefore OPG does not issue any long-term debt in the capital markets. The confirmation is further supported by OPG's limited credit-risk exposure, since its principal counterparty is the Independent Electric System Operator (IESO), a creation of the Province that receives its power through provincial regulation and legislation. (Continued on page 2.)

Rating Considerations

Strengths

(1) Dominant market position in Ontario
(2) Interim regulatory framework favourable to improving OPG's financial profile and strong financial metrics
(3) Nuclear waste management liabilities are limited due to agreement with Province
(4) Support of shareholder (Province of Ontario – rated AA)

Challenges

(1) Higher operating and financial risks associated with nuclear assets
(2) Future decommissioning costs and used fuel-storage above 2.23 million bundles
(3) Interim regulatory framework is less favourable than seen in other North American jurisdictions
(4) Fuel-cost risk associated with coal generation and nuclear to a lesser extent
(5) Political intervention
(6) Significant capital expenditure program

Financial Information

	12 mos. ended	For the year ended December 31			
	Sept. 30, 2007	2006	2005	2004	2003
EBIT interest coverage (times)	3.27	3.70	4.60	0.77	0.90
(Cash flow - n.w.f.*) / CAPEX (times)	1.04	1.43	1.94	0.62	(0.07)
(Cash flow - n.w.f.*) / Total debt	19.4%	24.9%	22.9%	9.3%	(1.2%)
Total debt-to-capital	35.6%	39.0%	43.8%	42.6%	42.6%
Net income (before extras) ($ millions)	404.1	504.1	615.7	54.8	(29.0)
Cash flow from operations ($ millions) **	1,265.1	1,513.1	1,481.7	851.8	482.0
Gross electricity generated (TWh)	104.7	105.2	108.5	105.0	109.1

* n.w.f. = nuclear waste funding. ** DBRS-adjusted.

Rating Rationale (Continued from page 1.)

While provincial ownership and financial support limited downward movement in OPG's ratings during earlier periods of weak financial performance by the Company, the current ratings takes into account OPG's improved financial profile on a stand-alone basis, which has improved due to a more favourable regulatory framework. The financial profile of OPG has improved since 2004, following the announcement of the interim regulated rate structure that came into effect on April 1, 2005. Credit metrics for the 12 months ending September 30, 2007, of 35.6% debt-to-capital, 20% cash flow-to-total debt and 3.27 times EBIT gross interest coverage were well within the range that one would expect for the ratings.

OPG's unregulated generation output accounts for approximately 38% of the Company's total generation output. While unregulated, these generating assets are considered to be of lower risk due to the fact that approximately 85% of their output is sold at the Ontario electricity spot market price, but subject to revenue limits that have been below the market price.

On November 2, 2007, OPG began the pre-submission consultations on its rate application for regulated assets (which account for 62% of OPG's electricity output). The Company intends on finalizing the rate application and submitting it to the Ontario Energy Board (OEB) at the end of November 2007. The application, if approved, would result in a 14% pricing increase from these assets and will result in OPG's first rate increase in three years.

Over the next few years, it is expected that OPG will generate sufficient cash flow from operations to fully fund nuclear waste and decommissioning funding, along with sustaining capital expenditures, but will require a manageable level of debt financing to fund development capital expenditures. Additionally, DBRS would expect the Province to forgo dividends during a period of heightened capital expenditures if necessary to preserve the Company's credit metrics. Cash flow-to-debt and interest-coverage ratios will likely come down modestly from their current levels, but are expected to remain more than adequate to support the current ratings.

There continues to be uncertainty regarding the closure of the Company's coal plants. In August 2007, the Province finalized a regulation that commits to the elimination of coal stations by December 31, 2014. Furthermore, in April and June 2007, the federal and provincial governments introduced climate-change plans and environmental policies with aggressive targets to reduce greenhouse gas emissions. The implications have not yet been determined.

The current ratings reflect all the challenges listed above, combined with the regulatory uncertainty going forward. DBRS notes that the regulatory framework has improved over the past couple of years, but the upcoming rate filing with the OEB will help establish key elements of the regulatory framework that the Company will require in the future, particularly if it undertakes a more aggressive capital expenditure program. Currently OPG's regulated rates are based on a return on equity (ROE) of 5%, which is low in comparison to what the majority of regulated generation companies receive in other jurisdictions in North America. Furthermore, under the existing regulated/price capped units, increases in expenses such as operating and maintenance (O&M) and fuel are generally not recoverable.

Over the long term, the Company is considering a number of potential capital projects, including the refurbishment of Pickering, new nuclear units at Darlington and a number of new hydro facilities. DBRS notes that although these potential capital expenditures could pose several significant financing challenges, the Province would be directly involved in the planning and development process and would be expected to provide financial support if necessary. DBRS notes that while the anticipated capital expenditures are likely to affect financial metrics, the financial support provided by the Province, combined with the improving operating performance from the Company and the upcoming OEB rate filing should support the current ratings going forward.

Ontario Power Generation Inc.

Report Date:
November 30, 2007

Rating Considerations Details

Strengths

(1) OPG's importance in Ontario is demonstrated by the fact that it is the primary generator in the Province, accounting for about 71% market share of electricity sold in the province. DBRS believes that OPG will continue to be the dominant generator in the province until at least 2014 when the coal-fired generation plants are scheduled to be closed and are replaced by other forms of generation. However, the majority of OPG's assets are now regulated and this proportion will increase when the coal plants are ultimately closed, significantly reducing OPG's influence on unadjusted wholesale electricity prices.

(2) The interim regulatory framework governing OPG has contributed to an improved financial profile compared with the previous Market Power Mitigation Agreement (MPMA), under which OPG has operated since market opening in 2002. The interim framework is expected to result in a weighted-average price of $45/MWh for regulated generation and $46/MWh to $48/MWh on about 85% of output from OPG's non-regulated generating facilities (with certain exceptions). These interim prices compare favourably to the previous average price received on OPG's generation since market opening of about $42.5/MWh. The Company's credit metrics have improved since 2004 and currently support the assigned ratings. At September 30, 2007, credit metrics were strong with 35.6% debt-to-capital, 20% cash flow-to-total debt and 3.27 times EBIT gross interest. OPG will be submitting a rate application to the OEB requesting a 14% price increase on its regulated assets to become effective April 2008.

(3) OPG established and manages, jointly with the Province a Used Fuel Fund (UFF) and a Decommisioning Fund (DF), which are funded by OPG in accordance with the Ontario Nuclear Funds Agreement (ONFA). Under ONFA, the Province guarantees OPG's annual rate of return on the UFF related to the first 2.23 million bundles used. The DF is currently over funded based on the 2006 approved reference plan.

(4) The Province indirectly provides OPG with all of its long-term funding requirements. The Province is the sole shareholder of the Company and is actively involved in the energy-planning process in Ontario and the overall business of the Company. The Province does not directly guarantee OPG or its financial obligations, however DBRS believes the Province will continue to support its investment since it is a creation of the Province and an integral part of meeting the energy needs of Ontarians. OPG on a project-by-project basis enters into negotiated agreements with the Ontario Electric Finance Corporation (OEFC) to finance the project. The Province has provided support to OPG in the past by extending the maturities on OPG's debt held by the OEFC on a number of occasions and by allowing OPG flexibility on dividends. Furthermore, the OEFC is the agency that provides OPG with long-term debt financing.

Challenges

(1) Nuclear generation accounts for approximately 30% of in-service generating capacity and approximately 45% of OPG's 2006 annual production. Nuclear contributions could increase to 59% in 2014 (the scheduled closing of the coal-fired plants) if the Company has not replaced the capacity of the coal-fired plants. Nuclear generation faces higher operating risks than other types of generation due to the complexity of the technology and financial implications of forced outages are greater given the high fixed-cost nature of these plants, as well as the fact that lost revenues resulting from outages are not recoverable through rates. Additionally, nuclear generation carries more regulatory and political uncertainty as a result of the risks associated with the ownership of these plants, such as evolving regulatory rules, safety targets and measures, and costs associated with used fuel-storage and future decommissionings. Furthermore, older nuclear units, such as those at Pickering, are more susceptible to forced outages. For example, in 2005/2006, Pickering A and B have had availability factors in the 70% to 78% range, compared to Darlington, which is newer and has had an average availability of 90%. OPG is undertaking a business case examination on the feasibility of the potential refurbishment and life extension of its Pickering B nuclear station.

(2) (2) A long-term risk facing OPG with respect to its nuclear facilities (as well as those leased to Bruce Power) is uncertainty with respect to the cost of long-term used fuel storage and future decommissioning costs. Under the ONFA, OPG bears the risk and the liability for cost increases and fund earnings in the DF. As at September 30, 2007, the DF is overfunded compared with the estimated completion costs for nuclear fixed-asset removal and the disposal of low- and intermediate-level nuclear waste materials per the most recently approved ONFA reference plan.

(3) The interim regulatory framework governing OPG, while an improvement over the previous pricing mechanisms, is less favourable than frameworks governing regulated electric utilities in many other jurisdictions in North America. OPG's regulated prices are supported by a deemed capital structure of 55% debt/45% equity for the regulated assets and an ROE of 5%. The 5% ROE and revenue cap on unregulated assets penalizes the Company more than other regulated electric utilities in the province. Both regulated transmission and distribution operations in Ontario, which have materially lower business risk profiles, have approved ROEs of 8.35% and 9% respectively. Furthermore, compared to vertically integrated utilities in the United States that have deemed equity components ranging from 35% to 55%, the ROEs are significantly higher, ranging from 9.0% to 13.0%. Additionally, there are generally no provisions under either the regulated or price-capped mechanisms under which operating cost increases (e.g., maintenance, fuel costs) can be recovered.

(4) OPG's fuel-price risk is mostly correlated to its fossil-fuel generation and, to a lesser extent, nuclear. The revenue rate cap currently imposed on fossil-fuelled generation does not account for an abnormal rise in coal prices or an unanticipated increase in coal use. To mitigate this risk, OPG has a fuel-hedging program for all fuel types. For 2007, 2008 and 2009, the Company has hedged 99%, 92% and 75% of its exposure, respectively. Therefore, margins can be constrained if fuel prices rise drastically, especially if the revenue cap is reached or if the volume of coal burned increases unexpectedly (as occurred during the past year).

(5) OPG is subject to political intervention, due largely to changes in government mandates and policies, as well as limits that restrict revenues and earnings should the price of electricity rise quickly. Due to political influence, OPG has been under-earning for a regulated utility. The Company is a creation of and wholly owned by the Province, therefore, it has been subject to various policy changes and interventions. DBRS notes the Province has committed to having OPG run more autonomously, however the risk of further government intervention still exists. The highly contentious policy review that centered on the closing of the coal-fired generating facilities in Ontario is a recent example of political issues that raise uncertainty for the Company and make it more challenging for OPG to undertake long-term strategic planning. In August 2007, the Province finalized a regulation that commits to eliminate the use of coal by December 31, 2014. Furthermore, in June 2007 and April 2007, the Province and Federal governments, respectively, introduced climate-change plans and environmental policies to reduce greenhouse gas emissions.

(6) OPG has a significant capital expenditure program underway and this is likely to increase given the potential new nuclear plants and the refurbishments of existing facilities under consideration. It is expected that OPG will not undertake any major capital projects without having its financing and a cost-recovery mechanism in place, thus minimizing the financial risks. It is also expected that OPG will turn to the OEFC or project-style financing in the capital markets to fund these projects. Although OPG may be able to reduce its risks through design-build contracts, some residual risk will remain on significant capital expenditures.

Regulation

Regulation pursuant to the Electricity Restructuring Act, 2004 (Ontario), allows OPG to receive regulated prices for electricity generated from its nuclear facilities (6,606 MW) and most of its baseload hydroelectric, namely Sir Adam Beck I, II and the Pump Generating Station; DeCew Falls I and II; and R.H. Saunders plant (totalling 3,332 MW), effective April 1, 2005. About 45% of OPG's installed in-service capacity, or 62% of its total generation output, is sold at regulated prices.

The initial regulated prices for electricity generated by OPG's regulated assets are:

- $33/MWh for the first 1,900 MWh in any hour of production from regulated baseload hydroelectric facilities; for production above 1,900 MWh in any hour, it will receive the Ontario electricity spot market price.
- $49.50/MWh for nuclear facilities.

These initial prices are expected to remain in effect until at least March 31, 2008, after which time the OEB will assume responsibility for establishing new regulated prices. Combined, this is expected to result in a weighted-average price of $45/MWh for regulated generation.

These regulated prices were established by the Province, based on a revenue requirement that takes into account a forecast of production volumes and total operating costs, a capital structure of 55% debt/45% equity for the regulated assets and an ROE of 5%.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85% of output from OPG's non-regulated generating facilities (with some exceptions) is subject to a revenue limit that was implemented on January 1, 2005. The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit returned to 4.7¢/kWh and will increase to 4.8¢/kWh effective May 1, 2008 (compared to the 2007 year-to-date hourly Ontario spot market price (HOEP) of 5.0¢/kWh). In addition, beginning April 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority (OPA) are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits are returned to the IESO for the benefit of consumers.

OPG must also maintain variance accounts for costs incurred and revenues earned or foregone on or after April 1, 2005, that are a result of differing amounts from the Province's forecasts that were used to establish the current regulated rates. These variance accounts capture differences that include poor hydrological conditions, changes to regulatory requirements or technological changes, transmission constraints or outages and other events that are beyond OPG's control, such as acts of God. Recovery of items in the variance account will be subject to approval by the OEB. We note that increases in costs, such as fuel expense and maintenance, are generally not included in these variance accounts.

On November 2, 2007, OPG began the pre-submission consultations on its rate application for regulated assets. The Company intends on finalizing the rate application requesting new payment amounts to become effective April 1, 2008, for a 21-month period and submitting it to the OEB at the end of November 2007. The application, if approved, would result in a 14% increase in revenues from these assets and will result in OPG's first rate increase in three years.

OPG's Price Structure

REGULATED

Baseload Hydro

~ 15 TWh

$33/MWh

Nuclear

~ 50 TWh

$49.50/MWh

- ROE of 5%
- Prices in effect until no earlier than March 31, 2008

UNREGULATED

REVENUE CAPPED

Intermediate & Peaking Hydro

~ 15 TWh

Coal stations

~ 30 TWh

85% of production capped (with some exceptions) at

$47/MWh May 1, 2007 to April 30, 2008

$48/MWh beyond May 1, 2008

MERCHANT

- Baseload Hydro beyond 1,900 MWh/hr (~2 TWh)
- Lennox output (0.3 TWh) (RMR* contract with IESO)
- 15% of remaining unregulated generation (~6 TWh)

*RMR = Reliability Must Run

Ontario Power Generation Inc.

Report Date:
November 30, 2007

Earnings and Outlook

Income Statement	12 mos ended	For the year ended December 31			
($ millions)	Sept. 30, 2007	2006	2005	2004	2003
Total revenues	5,594	5,564	5,798	4,926	5,178
EBITDA	1,285	1,583	1,878	1,076	993
Depreciation and amortization	658	664	753	765	603
Increase in net nuclear-related liabilities	16	128	95	140	192
EBIT	611	791	1,030	171	198
Gross interest costs	187	214	224	223	219
Net interest costs	150	193	197	189	144
Net income (before extras)	404	504	616	55	(29)
Non-recurring	(14)	(14)	(250)	(13)	(462)
Net income (as reported)	390	490	366	42	(491)
Return on avg. equity (before extras)	6.5%	9.1%	11.8%	1.1%	(0.6%)
EBIT by Segmented (before extras)					
Hydroelectric - Unregulated	349	375	423	n/a	
Fossil-fuel - Unregulated	45	(15)	189	n/a	
Total Unregulated	**394**	**360**	**612**	**228**	
Hydroelectric - Regulated	247	264	375	406	
Nuclear - Regulated	(99)	70	53	(468)	
Total Regulated	**148**	**334**	**428**	**(62)**	
Other *	69	97	(10)	5	
Total EBIT	**611**	**791**	**1,030**	**171**	

Note: With the introduction of rate regulation, reporting definitions of business segments were changed effect April 1, 2005.

* Includes EBIT associated with share of Brighton Beach joint venture, real estate rentals and trading activities. n/a=not available

Summary

Revenues have generally stabilized since the 2005 change to rate regulations that govern the nuclear and baseload hydro facilities.

The revenue reduction from 2005 levels is largely attributable to lower received pricing in 2006 as the revenue limit price was reduced ($0.046 in 2006 versus $0.049 in 2005) and lower wholesale prices on uncapped generation as the HOEP decreased materially from 2005 ($0.049 in 2006 versus $0.072 in 2005); and modestly lowered volumes in 2006 versus 2005 due to lowered demand attributable to less extreme weather in 2006 from 2005 (less heating and cooling degree days).

EBITDA has trended lower since 2005, largely due to reduced revenues (mentioned above), increased fuel costs as coal generation increased to compensate for lower nuclear output and increased OM&A attributable to higher pension and OPEB costs, as well as higher maintenance costs on nuclear and coal facilities. The negative impact on EBITDA of increased operating costs is a function of the pricing mechanics on the regulated and non-regulated but capped pricing assets; under which there is no recovery of increased costs such as fuel and OM&A.

Interest expense decreased on a last 12-months (LTM) basis, due to lower coupon rates and reclassification of interest expense related to Pickering A to a deferral account related to an amendment to regulation.

Outlook

In the near term, EBITDA and earnings should exhibit stability from current levels, although OPG's ability to manage costs will factor into this as cost fluctuations are generally not recoverable under either the regulated or revenue-capped assets. The Company is expected to submit a rate filing with the OEB on the regulated facilities, which OPG has stated would, if approved, result in a 14% rate increase, which would drive some improvement in margins. Additionally, market prices do impact the results on the non-price capped units, as evidenced by the 2005 earnings spike.

Ontario Power Generation Inc.

Report Date:
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Interest expense is expected to increase in the medium term, given the debt financing required to fund the increased capital expenditures, therefore coverage ratios will slightly weaken.

Longer-term earnings growth will be largely driven by capital projects coming into service from both current projects (i.e., the Niagara tunnel) and the large prospective projects under consideration. The closing of the coal-fired units in 2014 should not materially impact EBITDA or earnings as these assets currently do not provide a significant margin due to the revenue caps currently in place.

Financial Profile

	12 mos ended	For the year ended December 31			
($ millions)	Sept. 30, 2007	2006	2005	2004	2003
EBITDA	1,285	1,583	1,878	1,076	993
Net income adj. for non-recurring	404	504	616	55	(29)
Depreciation and amortization	658	664	753	765	603
Incr. in net liab. on decom. & waste fuel mgm't	16	128	95	140	192
Future income taxes	(16)	26	38	(117)	(100)
Recurring non-cash adjustments	203	191	(20)	9	(184)
Cash Flow From Operations	1,265	1,513	1,482	852	482
n.w.f.* and decommissioning	(547)	(599)	(521)	(506)	(525)
Common dividends	(128)	(128)	-	-	(17)
Capital expenditures	(691)	(637)	(494)	(561)	(643)
Free Cash Flow Before Work. Cap. Changes	(101)	149	467	(215)	(703)
Working capital changes	118	316	(147)	(83)	166
Net Free Cash Flow	17	465	320	(298)	(537)
Revenue limit rebate (including MPMA rebate)	(18)	(699)	300	0	0
Other investments & adjustments	(155)	(147)	(179)	(19)	334
Net debt financing	113	(521)	465	33	(135)
Net change in cash and s.t. inv.	(43)	(902)	906	(284)	(338)
EBITDA interest coverage (times)	6.87	7.40	8.38	4.83	4.53
Fixed-charges coverage (times)	3.27	3.70	4.60	0.78	1.00
Senior debt-to-capital (1)	28.4%	31.0%	36.0%	34.1%	34.0%
Total debt-to-capital (2)	35.6%	31.0%	36.0%	42.6%	42.6%
Net total debt-to-capital (3)	34.8%	39.0%	37.9%	42.6%	40.7%
(Cash flow - n.w.f.*) / CAPEX	1.04	1.43	1.94	0.62	(0.07)
(Cash flow - n.w.f.*) / Total debt	19.4%	24.9%	22.9%	9.3%	(1.2%)

(1) Senior debt = Senior debt held by the OEFC + Bank debt + A/R securitization (2) Total debt = Senior debt + Subordinated debt held by the OEFC.

(3) Net debt-to-capital = (Total debt - Cash) / (Total capital - Cash).

* n.w.f. = nuclear waste funding. This is subtracted from cash flow because the payments are not discretionary.

Note: Debt ratios include receivable sales as a debt equivalent.

Summary

Cash flow from operations has largely tracked EBITDA trends, with recent lower revenues and non-recoverable cost increases reducing cash flow. However, a marked improvement is evident since the imposition of regulated pricing in early 2005. Capital expenditures have ranged from $500MM to $700MM since 2003, with recent levels above the 2005 low point, due to increased spending on initiatives including the Portlands Energy Centre, investments in coal and nuclear facilities, and the Niagara Tunnel project. Funding for nuclear fuel waste and decommissioning, however, has remained reasonably steady.

Dividends to the Province were reinstituted in 2006 with a $128 million payment, the first dividend paid since 2003.

Operating cash flow in 2005 and 2006 was sufficient to cover nuclear waste fuel and decommissioning expenses, as well as capital expenditures and common dividends; although a small deficit (before working capital) was recorded on an LTM basis. Again, this represents a large improvement over pre-2005 levels.

While debt levels have fluctuated modestly year-over-year, they have been essentially flat since 2003. So, as a result, key credit metrics (debt/capital, EBITDA/interest and cash flow/debt) have all improved since 2004. The modest debt swings in 2005 and 2006 were driven by the timing of remittances under the revenue limit and MPMA payments.

Outlook

In the near term, operating cash flows are expected to be reasonably stable, compared with current levels, and should be sufficient to fund maintenance, capital expenditures and nuclear-waste fuel and decommissioning expenses. However, given the growth/enhancement projects currently under construction (Niagara tunnel, Portlands etc.), and a large expected nuclear-funds cash contribution, we would anticipate free cash flow deficits to be incurred. Note this does not assume the undertaking on any of as-yet uncommitted capital projects (Pickering B refurbishment, Darlington new unit construction, etc.).

Capital expenditures are expected to average $700 million in each of 2008 and 2009 (excluding the additional costs of any new projects), resulting in modest free cash flow deficits that would be funded with a modest increase in debt. As debt is added to fund capital expenditures, credit metrics would be expected to decline from current levels, as assets do not generate earnings or cash flows until placed in service. Once in service, metrics would be expected to improve.

Longer term, cash flow will be driven by prices received on the regulated and price-capped units, and incremental cash flow generated from new assets. The inclusion of any of the material capital projects currently under consideration would be the key drivers of cash flow deficits. DBRS would expect the Province to forgo dividends at a time of increased capital expenditures.

Long-Term Debt Maturities and Credit Facilities

Long-term Debt September 30, 2007 (CAD millions)	2007	2008	2009	2010	2011 & Thereafter	Total
OEFC Senior debt	200	400	350	595	920	2,465
OEFC Subordinated debt	-	-	-	375	375	750
Brighton Beach project debt	-	-	-	-	189	189
Total	200	400	350	970	1,484	3,404

Credit Facilities as at Sept. 30, 2007 (CAD millions)

Bank facilities	Maturity	Amount	Outstanding	Available
Committed credit facility - Tranche 1	May 21, 2008	500	0	500
Committed credit facility - Tranche 2	May 22, 2012	500	0	500
Short-term uncommitted credit facilities	No Maturity	238	201	37
Short-term uncommitted overdraft facilities	No Maturity	25	0	25
Total		1,263	201	1,062
OEFC facilities				
Niagara Tunnel project facility	Nov. 30, 2010	1,000	240	760
Portlands Energy Centre project facility	Dec. 31, 2009	400	160	240
Lac Seul project facility	Dec. 31, 2009	50	20	30
General corporate facility	Mar. 31, 2008	500	100	400
Credit facility	Sept. 22, 2009	950	200	750
Total		2,900	720	2,180

The OEFC provides OPG with its long-term debt financing on a project-by-project basis. OPG currently has a total of $1,450 million of project facilities with $420 million drawn as of September 30, 2007, for the Niagara Tunnel, Portlands Energy Centre and Lac Seul projects under construction. It is expected that OPG will not undertake any major capital projects without being assured of financing and an in-place cost-recovery mechanism, thus minimizing the financial risks.

The current debt maturity profile is shorter than comparable entities, considering the remaining asset life. This necessitates continued financial support from the Province to refinance OEFC debt maturities. Currently, the OEFC provides credit facilities totaling $1,450 million that consist of a $500 million general corporate facility maturing March 31, 2008, and a $950 million refinancing credit facility maturing September 22, 2009. The OEFC agreed to provide OPG with these facilities to restructure the existing OEFC debt that matures from June 2007 to September 2010. The refinanced debt has a maximum term of ten years at fixed rates, which will extend the Company's debt maturity profile.

OPG's liquidity is adequate for the rating category. The Company has a $1 billion syndicated bank credit facility that backs its $1 billion commercial paper program. This facility is comprised of a 364-day, $500 million tranche maturing in 2008 and a five-year $500 million tranche maturing in 2012. No commercial paper was outstanding as at September 30, 2007.

OPG has $215 million of short-term uncommitted credit facilities that are used to support Letters of Credit and a $25 million short-term uncommitted overdraft facility. At September 30, 2007, a total of $201 million of Letters of Credit were issued.

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OPG's liquidity is also supported by its securitization agreement (maturing August 2009) with an independent trust to sell receivables up to a maximum of $300 million. As at September 30, 2007, the maximum $300 million was outstanding.

At September 30, 2007, OPG's holdings of asset-backed commercial paper was $103 million, of which the Company expects $45 million will be recovered in late 2007. This level of exposure is not viewed as a material credit concern for OPG given its sizeable liquidity position.

Capital Expenditure Outlook

Significant Projects	Fuel Source	Budgeted Cost (CAD millions)	CAPEX Spent As of Sept. 30, 2007 (CAD millions)	CAPEX Remaining As of Sept. 30, 2007 (CAD millions)	Additional Capacity (MW)	Forecasted Completion
Under Construction						
Niagara Tunnel	Hydro	985	281	704	1,600	Late 2009 to mid 2010
Portlands Energy Centre 50/50 Joint Venture	Cogen.	400*	244*	156*	550**	Q2 2009
Lac Seul	Hydro	47	38	9	13	Q2 2008

* Figures reflect OPG's 50% share of the cost in the joint venture **This capacity is the total for the facility

Capital expenditures for the year ended 2007 are expected to be approximately $700 million to $1 billion, including amounts for the Niagara Tunnel project, Portlands Energy Centre and Lac Seul project.

OPG manages its construction risk by contracting with third parties for the construction of the projects, thereby transfering some of the construction cost over-runs, schedule-adherence and other construct-related risks to the contractor.

The Niagara Tunnel project is expected to increase annual generation capacity of the Sir Adam Beck generating stations in Niagara Falls by approximately 1,600 MW. The completion date for the Niagara Tunnel project is still expected to be mid-2010, despite slower progress by the tunnel-boring machine. It is anticipated that the project will be completed within the budget estimate and it is being debt financed through the OEFC.

OPG is currently jointly developing the Portlands Energy Centre cogeneration facility with TransCanada Energy Ltd. OPG will proportionately consolidate their 50-per-cent interest in the 550 MW joint venture. The project remains on schedule; single-cycle operation is expected to be on line by June 2008 and combined cycle by Q2 2009. OPG's $400 million share of the cost is being debt financed through the OEFC.

OPG's capital program is expected to remain significant over the medium to longer term, due to the large number of projects in OPG's concept/development pipeline, most notably a potential refurbishment of Pickering B, new nuclear units Darlington, the Upper/Lower Mattagami hydro development and a possible re-powering of the Lakeview site.

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Company Profile

Generation Portfolio

	Per Cent	Capacity (MW)	Plant Availability 9 mos Sept/07	Year ended 2006	2005	2004
Nuclear						
Darlington	*16%*	3,512	91%	89%	91%	88%
Pickering A	*5%*	1,030	42%	72%	70%	76%
Pickering B	*9%*	2,064	75%	75%	78%	70%
	30%	6,606				
Fossil-Fuel (1)						
Nanticoke (Coal)	*18%*	3,933				
Lambton (Coal)	*9%*	1,975				
Atikokan (Coal)	*1%*	215				
Thunder Bay (Coal)	*1%*	310				
Lennox (Duel oil & gas)	*10%*	2,140				
	39%	8,573	89%	86%	84%	81%
Hydroelectric						
Non-regulated (1)(2)	*16%*	3,639	94%	98%	99%	99%
Regulated (1)(2)	*15%*	3,332	94%	99%	99%	98%
	31%	6,971				
Huron & Pickering (Wind)	*0%*	7				
Total Capacity	*100%*	22,157				

(1) Fossil fuel and Hydroelectric plant availability is measured by equivalent forced outage rate by business segment

(2) Total hydroelectric portfolio comprises 64 stations.

Ontario Power Generation is responsible for approximately 71% of the electricity generation in the Province. As of December 31, 2006, OPG had a total in-service capacity of 22,147 megawatts (MW) and generated 105.2 terawatt hours (TWh) of electricity during the year. OPG's electricity-generating portfolio consists of the following:

- Three nuclear generating stations (Pickering A, Pickering B and Darlington), with a capacity of 6,606 MW.
- Five fossil-fuelled generating stations with a capacity of 8,578 MW.
- 64 hydroelectric generating stations with a capacity of 6,956 MW.
- Three wind-generating stations (which includes a 50% interest in the Huron Wind joint venture) with a capacity of 7 MW.

OPG partnerships consist of:

- OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own the Brighton Beach Generating Station, a 580 MW natural gas-fired generating station.
- OPG jointly owns with TransCanada Energy, the Portlands Energy Centre, a 550 MW natural gas-fired generating station that is currently under construction.
- OPG also owns two other nuclear generating stations, Bruce A and Bruce B, which are leased on a long-term basis to Bruce Power L.P.

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Balance Sheet	As at	As at December 31			As at	As at December 31	
($ millions)	Sept. 30, 2007	2006	2005		Sept. 30, 2007	2006	2005
Cash + short-term investments	235	6	908	Debt due one year	406	421	806
Accounts receivable	230	256	538	A/P + accr'ds + other	1,019	1,132	1,051
Future income taxes	-	-	18	MPMA rebate	67	40	739
Fuel	508	669	581	**Current Liabilities**	1,492	1,593	2,596
Material & supplies	178	112	115	Long-term debt	2,248	2,203	2,339
Current Assets	1,151	1,043	2,160	Subordinate l.t. debt	750	750	750
Net fixed assets	12,761	12,761	11,412	Waste mgmt. liab.	10,857	10,520	8,759
Defined pension assets	722	706	663	Other liabilities	589	539	580
Regulatory & other assets	791	646	600	Post-employ. benefits	1,529	1,396	1,212
Nuclear waste management fund	8,743	7,594	6,788	Equity	6,703	5,749	5,387
Total	24,168	22,750	21,623	**Total**	24,168	22,750	21,623

	12 months ended	For the year ended December 31			
Liquidity & Cash Flow Ratios	Sept. 30, 2007	2006	2005	2004	2003
Current ratio	0.77	0.65	0.83	0.73	0.87
Cash flow / CAPEX	1.83	2.38	3.00	1.52	0.75
(Cash flow - n.w.f.*) / CAPEX	1.04	1.43	1.94	0.62	(0.07)
(Cash flow - n.w.f.* - Dividends) / CAPEX	0.85	1.23	1.94	0.62	(0.09)
(Cash flow - n.w.f.*) / Total debt	19.4%	24.9%	22.9%	9.3%	(1.2%)
Leverage Ratios					
Senior debt-to-capital (1)	28.4%	31.0%	36.0%	34.1%	34.0%
Total debt-to-capital (2)	35.6%	39.0%	43.8%	42.6%	42.6%
Net debt-to-capital (3)	34.8%	39.0%	37.9%	42.6%	40.7%
Total gross debt / EBITDA	2.88	2.32	2.23	3.47	3.72
Coverage Ratios (4)					
EBIT interest coverage	3.27	3.70	4.60	0.77	0.90
Fixed-charges coverage	3.27	3.70	4.60	0.78	1.00
EBITDA interest coverage	6.87	7.40	8.38	4.83	4.53
Earnings Quality & Operating Efficiency					
Fuel costs / Revenues	22.0%	19.7%	22.4%	23.4%	32.4%
EBIT margin	10.9%	14.2%	17.8%	3.5%	3.8%
Net margin (before extras)	7.2%	9.1%	10.6%	1.1%	(0.6%)
Return on average equity (before extras)	6.5%	9.1%	11.8%	1.1%	(0.6%)
Profit returned to gov't (before extras)	49.9%	46.6%	34.5%	35.6%	127.4%
Common dividend payout (before extras)	31.7%	25.4%	0.0%	0.0%	(58.6%)

* n.w.f. = nuclear waste funding. This is subtracted from cash flow because the payments are not discretionary.

(1) Senior debt = Senior debt held by the OEFC + bank debt + securitization of receivables.

(2) Total debt = Senior debt held by the OEFC + bank debt + securitization of receivables + subordinated debt held by the OEFC.

(3) Net debt-to-capital = (Gross debt - cash) / (Total capitalization - cash).

(4) EBIT includes interest income. Interest expense before capitalized interest, AFUDC and debt amortizations.

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Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debt*	A (low)	Confirmed	Stable

* Debt held by the Ontario Electric Finance Corporation.

Rating History

	Current	2006	2005	2004	2003	2002
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A

Related Research

- Comments on ABCP Exposure, August 28, 2007
- Ontario Power Generation Inc., August 3, 2006
- Comments on New Electricity Pricing, February 23, 2005

Note:
All figures are in Canadian dollars, unless otherwise noted.

STANDARD & POOR'S CANADIAN RATINGS

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Ontario Power Generation Inc.

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Corporate Credit Rating

BBB+/Positive/--

Financial policy:
Moderate
Debt maturities:
2006 C$800 mil.
2007 C$400 mil.
2008 C$400 mil.
2009 C$350 mil.
2010-2012 C$1,745 mil.

Outstanding Rating(s)	
Ontario Power Generation Inc.	
CP	
Local currency	A-2
Ontario (Province of)	
Corporate Credit Rating	AA/Stable/A-1+
Sr unsecd debt	AA
Hydro One Inc.	
Corporate Credit Rating	A/Stable/A-1
Sr unsecd debt	
Local currency	A
CP	
Local currency	A-1

Corporate Credit Rating History	
Oct. 12, 2001	BBB+

Major Rating Factors

Strengths:

- Dominant position in a market with a strong and diversified economic base
- Government ownership and implied financial support
- Diversified portfolio of generating assets
- Low cost hydroelectric assets with river system diversity

Weaknesses:

- Uncertain sales volumes due to seasonality of electricity demand, variability in both river flows and asset operating performance
- Below-average financial profile related to low allowed returns on

regulated operations and an interim revenue cap on nonregulated operations
- Operational challenges at nuclear and coal-fired facilities
- Nuclear technology exposes company to significant risk and potential for unexpected large capital expenditures

Rationale

The ratings on Ontario-based electricity generator Ontario Power Generation Inc. (OPG) reflect the close relationship between the company and its higher rated owner, the Province of Ontario (AA/Stable/A-1+). Secure cash flows derived from OPG's regulated nuclear and regulated hydroelectric assets, a diverse portfolio of generating assets, and a strong cost competitive position in the Ontario wholesale electricity market further support the ratings. These strengths are partially offset by operational and technology risk associated with its nuclear assets, volume risk related to OPG's unregulated coal and hydroelectric assets, a price cap on the bulk of unregulated commodity sales, and a below-average but improving financial position.

OPG's ownership by the province significantly enhances the creditworthiness of the company. The close relationship between OPG and the province is expected to continue. This view is supported by the company's strategic position in Ontario's electricity sector and overall economy. The province's demonstrated willingness to financially assist the business and stated intention to continue to direct the company's future investments in major new generation is further evidence of a close relationship. The province has made a commitment to provide OPG with 100% debt financing for the C$1 billion Niagara tunnel project announced in September 2005. All of OPG's long-term debt is in the form of notes payable to the province. Furthermore, the likelihood of the privatization of OPG or further divesting of significant assets appears low.

Cash flow from all of OPG's nuclear production and a portion of its hydroelectric production is supported by a legislated fixed price of C$49.50 per MWh and C$33 per MWh respectively, until 2008. Based on forecast production, operating costs, and existing capital structure, the company should be able to earn about a 5% return on equity from its regulated operations that generate more than half of energy revenues. The ability to recover significant unexpected capital and operating costs offsets some of the potential negative financial impact related to the company's inherent operational risks. Cash recovery of these costs, if approved by the regulator, would be unlikely to begin before 2008 and could be spread out over a three-year period. If necessary, the generator may apply for a price increase before the implementation of full regulatory oversight by the Ontario Energy Board (OEB; the province's independent regulator) expected in 2008.

The fuel diversity and large number of units in OPG's generation portfolio mitigate the risk of operational disruptions and enhance the company's business position. The portfolio includes base-load nuclear (6,618 MW), predominantly run-of-the-river hydroelectric (6,962 MW), intermediate coal-fired (6,438 MW), and peaking gas- and oil-fired (2,140 MW) generation assets. Furthermore, OPG's hydroelectric assets are on multiple river systems, the diversity of which serves to partially offset OPG's exposure to hydrology risk. All told, the company's asset base includes more than 75 generating units with capacity ranging from 50 MW to more than 800 MW each.

OPG has a strong cost-competitive position in its primary market. The combined output of the generator's base-load regulated assets (about 60 TWh per year) is among the lowest cost generation in the province and is not exposed to significant dispatch risk. The Ontario electricity market can absorb all available nuclear generation output from OPG and its competitor Bruce Power Inc. (Bruce Power). OPG's unregulated hydroelectric generation can easily compete with higher cost oil- or gas-fired production to meet intermediate and peaking demand in the Ontario electricity spot market. Further strengthening its market position, OPG is the only Ontario-based coal-fired generator and the dominant player in the Ontario market, producing two-thirds or more of the approximately 150 TWh of electricity sold in Ontario each year.

There is significant operational and technology risk associated with nuclear generating assets. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in recent years. Although similar in concept, each station has design differences that add to the complexity of monitoring and maintaining their performance. OPG has a nuclear liability risk-sharing agreement with the province that caps the company's used nuclear fuel liabilities. Furthermore, OPG will have access to segregated funds to manage the costs associated with used fuel and eventual nuclear decommissioning. Until 2008 OPG is required to make a cash payment of C$454 million per year to the fund. Post 2008, annual contributions are scheduled to be reduced by about 15% but will remain a significant and ongoing drain on funds from operations (FFO) available to meet the company's debt and interest obligations.

Cash flow derived from OPG's unregulated coal-fired and hydroelectric assets is exposed to variability in production. Although cost-competitive with oil- or gas-fired generators, OPG's coal-fired fleet is exposed to competitively priced imports from neighboring markets. Furthermore, wear and tear on the coal-fired plants, that frequently ramp up and down, result in maintenance outages that can also reduce total output. Volume risk associated with OPG's unregulated hydroelectric production is due to the inherent uncertainty of available water flows. The reliability and availability of OPG's hydroelectric assets, however, is strong. OPG does not have significant water storage capability but is able to take some advantage of peak prices on a daily and weekly basis.

Until April 30, 2006, there is a C$47 per MWh revenue cap on approximately 85% of production from OPG's unregulated assets that limits the company's opportunity to increase cash flow from spot market sales. At the same time, the price cap on unregulated production is not a guaranteed floor. A small portion of OPG's cash flow remains exposed to volatile commodity prices. Given rising energy and electricity prices and the track record of government price setting in Ontario, there is some risk that the revenue cap will be extended.

Although OPG's financial profile has been weak in the past several years, it has shown improvement in 2005 and is expected to continue to strengthen in 2006. In assessing OPG's key credit ratios, such as FFO interest coverage and FFO to total debt, cash payments to segregated nuclear liability funds are deducted from cash flow from operations. Based on forecast production and the regulatory pricing scheme implemented May 1, 2005, FFO interest coverage could exceed 4x in 2005, after taking into consideration cash rebate payments related to the revenue cap due in May 2006, as compared with 3x coverage achieved in 2004. Furthermore, assuming the C$47 per MWh revenue cap on OPG's nonregulated output is removed as of May 1, 2006, and a full year's production from a second refurbished nuclear unit is achieved, FFO interest coverage could exceed 5x in 2006. On the same basis, FFO-to-total-debt is expected to increase to about 17% in 2005 and to or above 20% in 2006, as compared with about 10% in 2004. Total-debt-to-total-capital on an adjusted basis is expected to be about 42% in 2005 but based on the company's current plans for debt reduction, could improve in 2006 and 2007. On a forward-looking basis, given significantly higher FFO and lower capital expenditures, the company anticipates being in a position to repay C$1.2 billion in debt maturing in 2006 and 2007 that would contribute to further improvement in cash flow credit metrics. The extent of this marked improvement to cash flow adequacy, however, is subject to market price volatility, the lifting of the revenue cap, and the operating performance of OPG's generating assets, in particular its nuclear fleet.

Liquidity

Based on available credit lines, cash, expected cash flow, and demonstrated support from its government shareholder, OPG's liquidity should be sufficient to meet cash outlay commitments in the next 12 months.

OPG's C$1 billion fully committed credit facility has a C$500 million 364-day term tranche maturing May 23, 2006, and a C$500 million three-year term tranche maturing May 23, 2008. The facility serves as a backstop to the generator's C$1 billion CP program. At Sept. 30, 2005, the full amount under the credit facility remained available as no CP had been issued and the bank line remained undrawn. The C$1 billion bank facility remains available to support collateral requirements that could arise from the company's exposure to commodity market-related financial settlement risk. In addition, as of Sept. 30, 2005, OPG had about C$215 million (unaudited) under its separate standby LOC facilities, and C$549 million in cash and cash equivalents. A significant portion of the company's cash on hand is earmarked for rebate payments, due in May 2006, related to the C$47 per MWh revenue cap.

Based on average production of about 110 TWh and assuming the C$47 per MWh revenue cap on output from nonregulated assets is removed effective May 2006, OPG can expect to generate more than C$1 billion in FFO in 2006. Capital expenditures of about C$500 million (excluding the Niagara tunnel project) are anticipated in 2006, similar to about C$540 million in 2005. Given significantly improved earnings, the company is expected to resume dividend payments based on its 35% payout policy expected to be equivalent to about C$250 million in 2006. OPG plans to use any remaining cash flow to pay down debt maturing in 2006. Ongoing financial support from its shareholder enhances OPG's liquidity. Earlier in 2005 OPG borrowed an additional C$495 million from its shareholder to partially fund its 2005 cash requirements. OPG has access to a further C$200 million in preapproved funds from its shareholder until March 31, 2006.

Outlook

The positive outlook reflects the expectation of a significant improvement to OPG's cash flow and credit metrics in 2006 due to increased nuclear output and a full year of higher regulated prices. The anticipated removal of the C$47 revenue cap on 85% of OPG's unregulated output as of May 1, 2006, should also contribute to an improved financial position in 2006 and 2007. The positive outlook is further supported by the expectation of a period of relative stability in both Ontario's electricity policy and regulatory framework, and increasing transparency in decisions affecting the company's financial profile. The outlook could be revised to stable as a result of lower-than-expected market prices or significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities. A material change in the shareholder relationship is not expected to lead to a higher rating but could lead to a lower rating. Should the expected improvement in cash flow credit metrics materialize in 2006 and be considered sustainable in years beyond, the rating will likely move a notch higher.

Business Description

OPG, wholly owned by the Province of Ontario, is an electricity generator with both regulated (nuclear and hydroelectric) and unregulated (coal, hydroelectric, and oil- and gas-fired) assets. In addition to energy revenues, the company receives payments from Bruce Power L.P. that operates OPG's Bruce A and Bruce B nuclear stations under a long-term lease arrangement, and revenues from sales of radioactive isotopes used for medical treatments. The company also undertakes power-marketing activities; however, it is a minor part of its operations, representing less than 2% of total revenue.

Rating Methodology

Government shareholder support is a significant factor (two notches) in the final rating outcome on OPG. For a more detailed outline of the application of the government support methodology, the basis of the two-notch rating uplift, and circumstances where the level of implied government support can differ between related entities refer to "Credit FAQ: Implied Government Support As A Rating Factor For Hydro One Inc. And Ontario Power Generation Inc." published Oct. 20, 2005, on RatingsDirect, Standard & Poor's Ratings Services' Web-based credit research and analysis system, at www.ratingsdirect.com. For a more detailed outline of the rating criteria used, refer to "Revised Rating Methodology For Government-Supported Entities" published June 5, 2001.

Business Risk Profile

Profitability

OPG's profitability is a function of the fixed prices received for the output from its regulated nuclear and hydroelectric assets and the company's ability to meet its targeted nuclear production without exceeding forecast operating costs. Improved profitability will require prudent cost control and effective management of the company's ongoing maintenance and capital expenditure programs. A mechanism under the company's new license agreement serves to mitigate the potential negative impact on earnings of some cost overruns. The mechanism allows OPG to defer unexpected operating costs at OPG's regulated facilities and seek approval from the regulator for cost recovery post 2008.

Profitability of OPG's merchant segment is also a function of available hydrology and constrained by a government-imposed revenue cap that is in effect until April 2006. It is likely that OPG will earn an average C$47 per MWh on 85% of unregulated generation output until the revenue cap is removed. This average price implies a significant margin on unregulated hydroelectric output but a very modest margin for coal-fired production given rising fuel costs. OPG's owner has the legislative authority to extend or revise the revenue cap currently constraining profitability. Upside potential on the remaining 15% of OPG's unregulated merchant production, not subject to the revenue cap, is a function of electricity spot market prices, coal prices, and the U.S./Canadian exchange rate.

Regulation

OPG's satisfactory business profile is supported by price regulation of its key base-load assets. The transitional price cap regulation is intended to allow OPG to recover allowed costs and earn a return of 5% on equity for its regulated assets based on a notional 55% debt and 45% equity split of the regulated asset value in 2004. If OPG's costs or output performance differs from planned levels, OPG could earn more or less. Based on forecast production, OPG expects to receive an average price of C$45 per MWh from the combined output of its regulated nuclear (C$49 per MWh) and regulated hydroelectric assets (C$33 per MWh). OPG's regulated facilities include the Niagara River plants, the St. Lawrence River plant, the Pickering Nuclear Generating Station (A and B) and the Darlington Nuclear Generating Station. Total output from these facilities represents 41% of total Ontario generation (2005 estimate) and about 50%-60% of OPG's energy-related revenue.

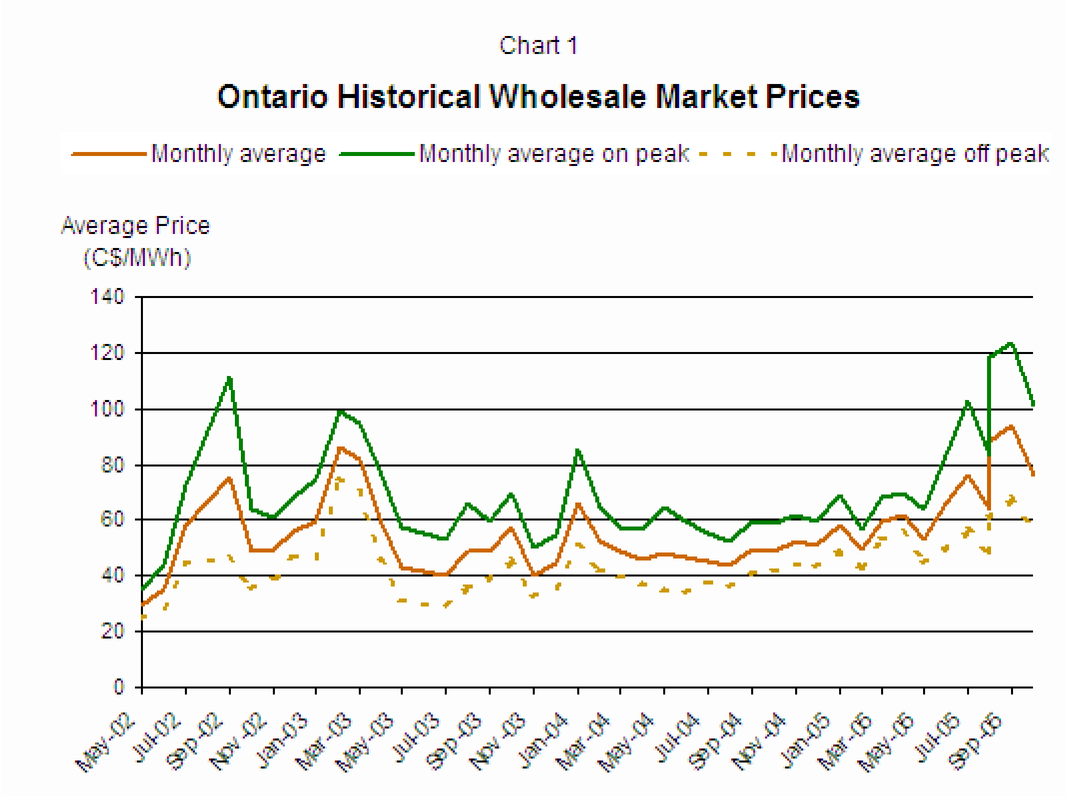
Recent legislative changes have created a transitional, slightly more transparent, pricing framework. The current pricing scheme, effective April 1, 2005, will remain in place until the OEB assumes regulatory oversight of the generator in 2008 or later. During the transition period, OPG is able to apply to its shareholder for adjustments to the current regulated price caps. OPG will track revenue and expenditures, and establish variance and deferral accounts related to unexpected operational costs OPG deems beyond its immediate control. The OEB will determine treatment of any established variance accounts; however, OPG is unlikely to benefit from any related cost recovery prior to 2008. Furthermore, post 2008, it is likely that the company's regulated rate base will be adjusted upward by the value of capital expenditures undertaken in the next few years that serve to extend operations or increase output of OPG's regulated facilities.

It will be several years before the nature of the OEB's eventual regulatory framework and of its relationship with OPG can be fully assessed. Although the regulator's independence with respect to local distribution companies in Ontario has improved significantly as a result of legislative changes since 2002, OPG is likely to be the first and only generator to fall under OEB's regulatory oversight. It remains to be seen whether the capital structure and returns allowed by the regulator post 2008 will reflect the much higher operating risks associated with electricity generation (including hydrology risk and nuclear technology risk) as compared with the low risk profile of distribution and transmission companies. For regulatory purposes, the capital structures of transmission and distribution utilities in Ontario have equity layers of between 35% and 45% and allowed returns on equity of 9% in 2006.

Markets

OPG operates primarily in Ontario, which is viewed as an above-average market characterized by a strong provincial economy and economic fundamentals that compare favorably with national averages. The growing province of Ontario, with a population of 12.4 million as of 2005, accounts for 40% of Canada's GDP. Ontario's GDP growth rate, which has generally outpaced the national average, has grown an average of 4% (nominal) per year during the period 2000-2004. In its May 2005 budget, the province forecast real GDP growth of 2.0% in 2005 and 2.8% in 2006.

Total electricity consumption in Ontario totaled 153 TWh in 2004 and is expected to continue to grow in the long term at about 1% per year. Steady growth in energy usage is due to increased commercial and residential consumption, mitigated by a decline in consumption by the Ontario manufacturing and resource base segment. Increased residential demand is due to recent strong increases in housing construction and a growing air-conditioning load. Average historical prices in the Ontario spot market for 2003, 2004, and the first three quarters of 2005 were C$57.60, C$52.20, and C$71.20 per MWh, respectively (see Chart 1). During the years 2006 and 2007 (prior to new gas capacity replacing OPG's coal-fired capacity), given a return to average available hydrology in Ontario, expected nuclear output, and normal weather conditions, the rolling 12-month average electricity spot price could decrease modestly from its current level of about C$65 per MWh.



Operations
The excellent diversification of OPG's existing generation portfolio (see Table 1 and Table 2), that serves to mitigate cash flow exposure to hydrology and nuclear-related operating risks, is expected to decrease significantly. By 2009 the company is expected to cease operations of its more than 6,000 MW of coal-fired generation to comply with its owner's energy policy. The company may, however, retain about 2,500 MW of gas- or oil-fired production capacity. OPG's generating assets produced 105 TWh during 2004 of which about a third was derived from hydro, about 40% from nuclear, and about a quarter from coal.

Table 1 Ontario Power Generation Inc. Generation Portfolio

	MW	Fuel	Regulatory Status
Nanticoke	3,938	Low sulphur coal	Unregulated
Lambton	1,975	Low sulphur coal	Unregulated
Thunder Bay	310	Lignite	Unregulated
Atikokan	215	Lignite	Unregulated
Lennox	2,140	Oil/Gas	Unregulated
Total fossil fuel capacity	8,578		
St Lawrence River	1,045	Hydro	Regulated
Niagara	2,326	Hydro	Regulated
Mattagami	495	Hydro	Unregulated
Ottawa River	912	Hydro	Unregulated
Madawaska River	615	Hydro	Unregulated
Abitibi River	501	Hydro	Unregulated
Other rivers	1,068	Hydro	Unregulated

Total hydroelectric capacity	6,962		
Pickering A	1,030	Uranium	Regulated
Pickering B	2,064	Uranium	Regulated
Darlington	3,524	Uranium	Regulated
Total nuclear capacity	6,618		
Total capacity	22,158		
N.M.--Not meaningful. Data as of Sept. 30, 2005.			

Table 2 Ontario Power Generation Inc. Portfolio Diversification		
	MW	**Portfolio Diversification (%)**
Fossil fuel capacity	8,578	39
Hydroelectric capacity	6,962	31
Nuclear capacity	6,618	30
Total capacity	22,158	100
Regulated 2005	9,989	45
Regulated post 2008 after coal plants are shut down	9,989	61
Data as of Sept. 30, 2005.		

OPG's hydroelectric assets have lower operating risk than either the coal-fired or nuclear-fueled assets, as illustrated by strong capability factors and low forced outage rates. OPG is expected to continue to invest a modest but appropriate level of capital in its long-lived hydroelectric assets. Capital spending of C$300 million is earmarked for hydroelectric maintenance in the period 2006 to 2009 but also targets modest increases in station capacity. Although the in-service dates of the company's hydroelectric assets range from 1898 to 1971, OPG's two largest hydroelectric facilities (representing about 36% of OPG's total hydroelectric capacity) are among the youngest at about 50 years old.

Achieving an improvement in the overall performance of the company's entire nuclear fleet is a key challenge for OPG. Capability factors are reported quarterly for each of the three nuclear stations. OPG has typically been unable to meet targeted performance in the past several years in part due to longer-than-anticipated maintenance and inspection outages. The future performance of the Pickering A station, which includes two refurbished operating units, one of which returned to service in 2003 and the other in November 2005, remains uncertain. Although the performance of the Pickering B station has improved significantly as of Sept. 30, 2005, compared with previous years, it remains below historical global standards (see table 3). Darlington, the newest of the three stations, has performed consistently better than Pickering A and B stations.

Table 3 Ontario Power Generation Inc.--Historical Nuclear Performance										
	2005		**2004**		**2003**		**2002**		**2001**	
	Target	Actual*	Target	Actual	Target	Actual	Target	Actual	Target	Actual
Capability Factor¶										
Industry benchmark	N/A	N.A.	N/A	N.A.	N/A	91.3	N/A	91.3	N/A	90.6
Pickering A§	94.7	60.0	77.9	73.3	91.0	70.3	N/A	N/A	N/A	N/A
Pickering B	76.3	79.8	73.0	69.7	81.0	67.8	80.5	80.9	76.1	73.3

Darlington	91.5	90.0	87.7	87.5	84.3	81.7	89.9	90.3	88.1	85.8
*As of Sept. 30, 2005. ¶Capability factor represents the amount of electricity the station is actually capable of producing as a percent of its potential capacity. §Prior to 2003, all four nuclear units at Pickering A were not operational. N.A.--Not available. N/A--Not applicable.										

The company's coal-fired units were designed to run as midmerit units with capacity factors typically below 50%. Despite the wear and tear of higher-than-expected production in the past several years, net capability factors for OPG's aging coal-fired plants remain better than 70%. The shutdown of 1,140 MW of coal-fired capacity at OPG's Lakeview facility in early 2005 and abnormal weather-related peak demand in the summer challenged OPG's remaining coal operations in 2005. The return to service of about 2,400 MW of base-load nuclear generating capacity in the Ontario market since October 2004, however, has served to offset demand for fossil fuel-fired generation production.

Fuel risk

Although operating risk is relatively low for OPG's hydroelectric generating units compared with the rest of the generation portfolio, variable hydrology is a significant risk. Two key assets on the Great Lakes, in addition to the benefits of more than 200 run-of-the-river plants on numerous river systems throughout the province, however, alleviate much of OPG's hydrology risk. This view is supported by OPG's consistent performance relative to peers despite several years of low water in most parts of Canada, including Ontario. In the past five years, OPG's total hydroelectric energy production has fluctuated by plus or minus 1%-6% from average historical annual production of 34.7 TWh. Total production was up at 35.7 TWh in 2004 as compared with 32.4 TWh in 2003. The Niagara Falls facilities (harness the water flow between two adjoining Great Lakes) produce almost 40% of OPG's hydro-based electricity output. A further 20% of OPG's hydroelectric production is derived from the St. Lawrence River that connects the Great Lakes to the Atlantic Ocean.

OPG's exposure to increasing coal prices is partially mitigated by its hedging program. As of Sept. 30, 2005, OPG had hedged 100% of its total estimated fuel (all fuels) requirements for 2005 and 93% of its 2006 estimated fuel requirement. About 90% of the coal used at OPG's fossil fuel stations is shipped across the Great Lakes with related fuel transportation risk. To mitigate this risk, OPG maintains sufficient inventories for typically higher demand winter months when the shipping lanes are closed. Fuel expense of about C$1 billion accounts for more than 70% of the total production cost of OPG's fossil fuel generation. The bulk of this cost represents purchases in U.S. dollars that expose OPG to some foreign-exchange risk.

Asset retirement obligations

The costs associated with the retirement of nuclear generation are material but OPG's exposure is mitigated to some degree by a growing cash reserve to fund nuclear asset decommissioning and waste management. In addition, OPG has established a nuclear liability risk-sharing framework with the province that will cap the company's exposure to nuclear-related liabilities at C$10 billion. As of Sept. 30, 2005, the fund had a fair value of C$7 billion.

Construction risk

OPG's near-term exposure to construction risk is limited. The company completed the refurbishment of a second nuclear unit, Unit 1, at its Pickering A station in 2005. The construction of a 10.4-kilometer tunnel at OPG's Sir Adam Beck facility at Niagara Falls has been contracted out as a fixed price turnkey project and, as such, presents limited liability to OPG. As OPG proceeds in the next several years with the shutdown of its coal-fired facilities, there is a likelihood of modest exposure to construction risk at site(s) where the government approves the construction of gas-fired replacements.

Within a 10-year time frame, however, further nuclear refurbishments are likely required given the average age of OPG's nuclear plants is 21 years of an expected 30-year life (with the potential for 10-year life extensions). It is unclear whether efforts to launch approvals for new nuclear capacity or major hydroelectric developments in Ontario will be forthcoming in the near term and if so, whether OPG will participate.

Competitiveness
OPG's strong competitive position in the Ontario electricity spot market is founded on the low marginal operating costs of its hydroelectric and nuclear generating facilities. Although there are other independent hydroelectric and nuclear operators participating in the spot market, the demand for energy and capacity is such that nuclear and hydroelectric generators have relatively modest exposure to dispatch risk. Access to interconnected markets in New York and Michigan where OPG's generation is also competitively priced (on a marginal cost basis) further reduces the company's dispatch risk. OPG's competitive position as a coal-fired generator is also strong. OPG owns all the coal-fired assets in Ontario and they are cost competitive with gas-fired production in Ontario and neighboring jurisdictions. OPG's volume of coal-fired production is most affected by weather conditions, OPG's and Bruce Power's nuclear unit availability, and available water flow in the province.

Hydroelectric imports from Quebec and Manitoba do not pose an immediate competitive threat to OPG, although they do provide Ontario with some added supply security. Imports from Quebec are exposed to transmission constraints and faster-than-expected growth in Quebec's domestic electricity demand. Imports from Manitoba are scheduled to increase modestly in 2006 and 2007 to assist with the tight supply in Ontario. Discussions continue at the provincial level regarding the potential for more significant imports from Manitoba and Quebec beyond 2015 that would involve major generation developments, in addition to significant transmission expansion in all three provinces.

Financial Risk Profile

Accounting
OPG's consolidated financial statements are prepared in accordance with Canadian GAAP. The accounting policies OPG adopted in preparing its 2004 financial statements appear reasonable. OPG has adopted several new accounting recommendations, none of which have a material effect on its financial statements. These include Accounting Guideline 13 regarding hedging relationships, the accounting of the disposal of long-lived assets and discontinued operations, and additional disclosure requirements of employee future benefits.

In assessing OPG's creditworthiness and overall financial profile, Standard & Poor's treats payments to nuclear waste and decommissioning funds as a cost of ongoing operations and deducts them from FFO before working capital, as presented in the company's financial statements.

In a bid to quantify the financial risk involved in trading activities, Standard & Poor's will, if appropriate, make an adjustment to a company's financial profile by adding a capital adequacy requirement to the balance sheet that is representative of the estimated market, credit, and operating risks associated with these activities. No such adjustment was made to OPG's balance sheet because, given the company's risk exposure, the amount was not material. Energy trading represents less than 2% of the company's total revenues.

OPG engages primarily in asset-backed physical trades, bought and sold at the Ontario border, and typical commitments are less than a year in duration. Counterparty risk for energy-trading transactions is concentrated in 'BB' territory but is very small.

Financial Policy: Moderate
OPG's moderate dividend policy is to pay the province, from time to time, approximately 35% of its net income in addition to special dividends related to the sale of assets. No dividends were paid in 2003 or 2004, however, OPG is expected to resume dividend payments based on anticipated 2005 earnings. Special dividends to the province have been paid in the past relating to the government-directed sale of the assets.

Although OPG's financial policy is to maintain total-debt-to-total-capital at 50% or less in the long term, this could change once the OEB assumes oversight of OPG's regulated assets in 2008 or later.

Cash flow adequacy
OPG's cash flow could almost double in 2005 to about C$640 million and potentially double again in 2006 to more than C$1 billion, as compared with about C$340 million in 2004. The expected improvement in cash flow is linked to increased margins resulting from a more favorable pricing scheme, and increased nuclear output resulting from improved overall performance and the return to service of Pickering A nuclear Unit 1. Further cash flow improvement in 2006 is premised on the removal of the C$47 per MWh revenue cap in May 2006 and average market prices above C$55 per MWh. Without the prospect of significantly improved cash flow on the immediate horizon, historical coverage levels, prior to the implementation of the new pricing scheme in second-quarter 2005, were insufficient to support an investment-grade rating on a stand-alone basis. OPG's weak credit metrics in 2003 and 2004, however, were less of a concern, given the company enjoyed and was expected to continue to benefit from meaningful shareholder support.

In the longer term, OPG's cash flow adequacy faces considerable challenges given the government's policy to phase out all coal-fired stations post 2007. OPG's credit metrics could be adversely affected in the longer term given the combined effect of lost revenues, significant capital spending associated with site remediation, and no reduction in related debt servicing requirements. These risks could be offset somewhat, by the conversion of the coal plants to an alternative fossil fuel, or by the sale of the sites with proceeds directed to remediation works or debt reduction. The timing of the coal plant retirements is uncertain and dependent on the successful construction of replacement capacity (primarily gas and wind) by independent generators and significant investment in Ontario's transmission infrastructure. A provincial election, likely in 2007, could also result in a change in energy policy.

OPG's sustaining, nondiscretionary capital expenditure program is significant at about C$500 million in 2006. Ongoing capital expenditures include the cost of maintaining OPG's existing fossil-fueled assets in good working order, maintaining almost 300 remote hydroelectric facilities, and ongoing care of 10 operating CANDU reactors. Although OPG faces significant uncertainty regarding its total level of capital expenditures, access to debt financing for shareholder-directed initiatives is not a concern, given that OPG's shareholder has consistently made additional funds available in a timely manner. To date, OPG's owner has directed the company to proceed with the Niagara tunnel project, and the conversion of OPG's Thunder Bay plant to gas from coal. During the next 10 years, it is unclear if the province will approve the refurbishment of OPG's Pickering B and Darlington nuclear stations or direct OPG to build or procure new nuclear facilities; either would involve billions of dollars of additional capital spending.

Liability management

Refinancing risk, related to debt maturities in 2006 that amount to about 25% of OPG's total debt, is not a concern, given OPG's relationship with its shareholder. All of OPG's debt is in the form of notes payable to its shareholder, who has consistently refinanced OPG's debt outstanding at maturity in each of the past three years. Average debt duration is relatively short, at about 3.5 years, compared with its long-life assets. Debt maturities are spread over the next seven years. Interest rate exposure is limited, given that rates are fixed for OPG's existing long-term debt.

The Niagara tunnel project, announced in September 2005, will be entirely debt financed by the province and as such does not present additional financing risk to OPG. Given the absence of any equity funding, when the asset is rolled into OPG's regulated rate base, likely in 2009, it will have a noticeable negative impact on the company's capital structure. The tunnel construction is expected to cost about C$1 billion and be completed during the period 2005 to 2009.

Financial flexibility

The keystone to OPG's average financial flexibility is its supportive owner, with deep pockets and demonstrated record of support. In the past two years the company has been able to negotiate the deferral of significant debt maturities with its owner. The shareholder has also demonstrated a willingness to forgo dividend payments and, if necessary, could be expected to support OPG's short-term liquidity, if only by allowing the deferral of various payments OPG makes to the province. Based on past experience, access to additional debt financing from OPG's owner is expected should it be required. Further flexibility is derived from the regulatory framework that includes an ability to recoup unexpected costs if approved by the regulator. Financial flexibility is restricted, however, by little discretionary capital spending, no indication of additional equity injections from the shareholder, political constraints on the sale of assets, and the potential for the province to direct the company to make investments in projects that the company's board of directors does not deem viable on a commercial basis.

Table 4 Ontario Power Generation Inc. -- Peer Comparison*

Industry Sector: Electric Utility Companies -- Canada

	--Average of past three fiscal years--			
	Ontario Power Generation Inc.	**TransAlta Corp.**	**Emera Inc.**	**Exelon Corp.**
Rating	BBB+/Positive/--	BBB-/Stable/--	BBB+/Negative/--	BBB+/Watch Neg/A-2
	(Mil. C$)	(Mil. C$)	(Mil. C$)	(Mil. US$)
Sales	5,280.7	2,356.9	1,226.7	14,735.3
Net income from cont. oper.	(134.0)	168.7	113.9	1,434.7
Funds from oper. (FFO)	205.7	545.5	277.7	3,718.3
Capital expenditures	691.0	622.4	127.6	1,995.3
Total debt	3,716.6	3,188.4	1,975.1	15,018.3
Preferred stock	0.0	359.2	263.0	256.3
Total capital	8,844.3	6,324.3	3,565.2	23,870.3

Ratios				
EBIT interest coverage (x)	0.1	1.5	2.1	3.9
FFO interest coverage (x)	2.3	3.2	2.7	5.5
Return on common equity (%)	(3.2)	5.4	8.4	17.1
NCF/capital expenditures (%)	23.3	58.6	136.9	152.6
FFO/total debt (%)	5.9	16.6	13.9	25.5
Total debt/capital (%)	42.0	50.4	55.4	63.7

*Adjusted by capital operating leases and off-balance-sheet obligations.

Table 5 Ontario Power Generation -- Financial Summary*

Industry Sector: Electric Utility Companies -- Canada							
	--Average of past three fiscal years--		**--Fiscal year ended Dec. 31--**				
Rating history			BBB+/Developing/--	BBB+/Watch Neg/--	BBB+/Watch Neg/--	BBB+/Stable/--	N.R.
	Sector median	**Issuer**	**2004**	**2003**	**2002**	**2001**	**2000**
(Mil. C$)							
Sales	901.6	5,280.7	4,918.0	5,178.0	5,746.0	6,239.0	5,978.0
Net income from cont. oper.	85.8	(134.0)	42.0	(491.0)	47.0	152.0	605.0
Funds from oper. (FFO)	215.0	205.7	335.0	30.0	252.0	738.0	1,033.0
Capital expenditures	124.7	691.0	561.0	643.0	869.0	739.0	585.0
Total debt	1,213.0	3,716.6	3,747.7	3,745.8	3,656.3	3,220.0	3,573.0
Total capital	2,398.3	8,844.3	8,768.7	8,724.8	9,039.3	8,690.0	9,390.0
Ratios							
EBIT interest coverage (x)	2.6	0.1	0.8	(1.5)	1.0	1.9	6.0
FFO interest coverage (x)	3.3	2.3	2.8	1.5	2.6	4.8	6.1
Return on common equity (%)	10.0	(3.2)	0.8	(10.5)	0.1	2.2	10.4
NCF/capital expenditures (%)	83.6	23.3	63.7	4.3	12.7	49.1	141.5
FFO/total debt (%)	18.7	5.9	9.1	1.1	7.6	21.7	29.5
Total debt/capital (%)	52.9	42.0	42.7	42.9	40.4	37.1	38.1

*Adjusted by capital operating leases and off-balance-sheet obligations. N.R.--Not rated.

STANDARD & POOR'S

CORPORATE RATINGS

Credit Rating:
BBB+/Positive/—

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RatingsDirect
Publication Date
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Ontario Power Generation Inc.

Rationale

The ratings on Ontario Power Generation Inc. (OPG), a large electricity generator, reflect the close relationship between the company and its higher rated owner, the Province of Ontario (AA/Stable/A-1+). A fixed price for output derived from OPG's baseload nuclear and hydroelectric assets, a diverse portfolio of more than 22,000 MW of in-service generating capacity, and a strong cost-competitive position in the Ontario wholesale electricity market, support OPG's cash flows and provide further credit strength. Operational and technology risk associated with its nuclear assets, revenue constraints, volume risk related to production from OPG's unregulated assets, and a satisfactory financial profile partially offset the company's credit strengths.

The government's demonstrated willingness to financially assist the publicly owned generator is reflected in a two-notch rating enhancement to the stand-alone long-term corporate credit rating on OPG. This view is supported by the company's strategic position in both the electricity sector and overall economy of Ontario. The government's continued direction of the company's investments in major new generation and provision of debt financing for the business is further evidence of a close relationship. Standard & Poor's is of the opinion that OPG is unlikely to be privatized in the foreseeable future. The government shareholder held OPG's notes payable of C$3.4 billion as of June 30, 2006, representing the bulk of OPG's debt outstanding.

Cash flow from all of OPG's nuclear and a portion of its hydroelectric production (derived from assets designated as regulated) is currently supported by legislated prices of C$49.50 per megawatt-hour (MWh) and C$33.00 per MWh, respectively, that are fixed until April 30, 2008. Based on forecast production, operating costs, and existing capital structure, the company should be able to earn about a 5% ROE from its regulated assets that generate more than half of its energy revenues. OPG can request future recovery of significant unexpected capital and operating costs associated with its regulated assets. Before the implementation of full regulatory oversight of these assets by the Ontario Energy Board (the province's independent regulator), which is expected in 2008, OPG may apply to its shareholder for an increase to the aforementioned legislated fixed prices.

The fuel diversity and large number of units in OPG's generation portfolio mitigate the risk of operational disruptions and enhance the company's business position. The portfolio includes baseload nuclear (6,606 MW), predominantly run-of-the-river hydroelectric (6,946 MW), intermediate coal-fired (6,438 MW), and peaking gas- and oil-fired (2,140 MW) generation assets. Furthermore, OPG's hydroelectric assets are on multiple river systems, the diversity of which serves to partially offset OPG's exposure to hydrology risk.

OPG has a strong cost-competitive position in its primary market, the Ontario wholesale electricity market. OPG is the dominant player in the Ontario electricity market, producing two-thirds or more of the approximately 150 terawatt-hours (TWh) of electricity sold in Ontario each year. The combined output of the generator's baseload regulated assets (about 60 TWh per year) is among the lowest cost generation in the province and, as such, dispatch risk is not material. The bulk of the remaining electricity demand in Ontario is met by competitive-based offers from OPG and other generators in an hourly spot market administered by the Independent Electricity System Operator.

There is significant operational and technology risk associated with nuclear generating assets. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in the past. OPG's nuclear liability risk-sharing agreement with the province caps the company's used nuclear fuel liabilities and is a positive for the credit. Furthermore, OPG will have access to segregated funds to manage the costs associated with used fuel and eventual nuclear decommissioning. The decommissioning fund was fully funded as of June 30, 2006, based on the latest Ontario Nuclear Funds Agreement reference plan (from 1999).

OPG's nonregulated cash flow is constrained by a government-imposed revenue cap until April 30, 2008, and is also exposed to volume risk. The revenue cap affects approximately 85% of production from OPG's unregulated coal-fired and hydroelectric assets; the cap will rise to C$48/MWh in 2008/2009 from C$46/MWh in 2006/2007. Volume risk relates to fluctuations in Ontario-based market demand, the inherent uncertainty of available water flows, and competitively priced imports from neighboring markets. Cash flow from the remaining 15% of nonregulated production is exposed to volatile commodity prices but is not precluded from benefiting from higher market prices.

OPG's financial profile showed significant improvement in 2005, with funds from operations (FFO) interest coverage of 6.2x and FFO-to-average total debt of 30%, compared with 2.5x and 9%, respectively, in 2004. Much lower cash flow in 2004 was in large part due to the previous C$38/MWh revenue cap on 80% of the company's entire output. OPG can be expected to maintain FFO interest coverage of more than 5x in 2006 and 2007 and FFO-to-average total debt of about 30%. The marked improvement to cash flow adequacy is subject to market price volatility, available water resources for OPG's hydroelectric generation assets, and the operating performance of OPG's nuclear fleet. In assessing OPG's key credit ratios, such as FFO interest coverage and FFO-to-average total debt, cash payments to segregated nuclear liability funds are treated as an operating expense.

Liquidity

Based on available credit lines, cash on hand, expected cash flow, and credit facilities established with its shareholder to fund government directives, OPG's liquidity should be sufficient to meet cash outlay commitments in and the next 12 months.

OPG has a C$1 billion, fully committed credit facility with a C$500 million, 364-day term tranche maturing May 22, 2007, and a C$500 million, three-year revolving tranche maturing May 22, 2009. The C$1 billion facility serves as a backstop to the generator's C$1 billion CP program. At June 30, 2006, the full amount under this credit facility remained available as no CP had been issued and the bank line remained undrawn. As such, the facility remained available to support collateral requirements that arise from the company's exposure to commodity market-related risk. OPG also had about C$99 million available under its separate C$240 million standby LOC facilities. LOCs issued relate primarily to the company's pension obligations. OPG also has credit facilities in place with its shareholder to fully debt finance new developments under construction. In April, the company made its first 2005 rebate payment of C$739 million related to its revenue cap and as such its cash position as of June 30, 2006, of C$360 million was much lower than C$919 million as of March 31, 2006.

OPG can expect to generate about C$1.1 billion in FFO in 2006 after cash payments of C$454 million to its nuclear liability fund. Sustaining and growth capital expenditures of about C$750 million are expected in 2006, similar to the C$763 million spent in 2005. There is the potential for OPG's shareholder to expect the company to resume dividend payments. Based on the 35% dividend payout policy applied to 2005 earnings, the dividends could be as much as C$150 million in 2006. Should this be the case, OPG would have sufficient cash and credit facilities available to meet its capital commitments and distributions but would have less cash available to direct toward expected debt reduction.

Outlook

The positive outlook is an indication that the rating will likely move a notch higher if OPG can manage its expenses and operational performance within the bounds of its current license agreement and maintain its satisfactory financial profile in 2006 with a similar outlook for 2007 and beyond. For the rating to move a notch higher, there will also have to be an expectation of continued relative stability in both Ontario's electricity policy and regulatory framework. The outlook could be revised to stable or negative as a result of a sustained period of significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities, or higher operating expense due to poor hydrology and higher prices for coal, with no related increase to the revenue cap. As the shareholder relationship evolves in the long term, there could be a change to the degree of support factored into the rating.