

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	2002	2001
	Restated (note 5)		Restated (note 5)	
Revenues	1,648	1,635	4,486	4,681
Fuel	412	393	1,147	1,099
Power purchased	36	374	344	649
Gross Margin	1,200	868	2,995	2,933
Operating expenses				
Operation, maintenance and administration	581	603	1,793	1,861
Depreciation and amortization	188	202	566	606
Property and capital taxes	29	2	88	46
Restructuring costs (note 6)	12	-	222	-
Loss on transition rate option contracts (note 4)	-	-	210	-
	810	807	2,879	2,513
Operating income	390	61	116	420
Other income (note 11)	11	-	117	-
Net interest expense	36	31	114	102
Income before income taxes	365	30	119	318
Income taxes (recoveries) (note 13)				
Current	131	(175)	86	97
Future	19	124	(28)	21
	150	(51)	58	118
Net income	215	81	61	200
Basic and diluted earnings per common share (dollars)	0.84	0.32	0.24	0.78
Common shares outstanding (millions)	256.3	256.3	256.3	256.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

(millions of dollars)

	Nine Months Ended September 30	
	2002	2001
	Restated (note 5)	
Retained earnings, beginning of period as previously reported	344	691
Adjustment (note 5)	-	(124)
Retained earnings, beginning of period as restated	344	567
Net income	61	200
Dividends	(134)	(238)
Retained earnings, end of period	271	529

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(millions of dollars)

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001 Restated (note 5)	2002	2001 Restated (note 5)
Operating activities				
Net income	215	81	61	200
Adjust for non-cash items:				
Depreciation and amortization	188	202	566	606
Deferred pension asset	(1)	4	3	40
Other post employment benefits	7	23	59	80
Future income taxes	19	124	(28)	21
Provision for restructuring	12	-	222	-
Transition rate option contracts (note 4)	(25)	-	167	-
Gain on sale of investments	(11)	-	(18)	-
Gain on sale of decontrol fixed assets	-	-	(99)	-
Mark to market on energy contracts (note 9)	6	-	4	-
Other	33	23	99	46
	443	457	1,036	993
Contributions to fixed asset removal and nuclear waste management fund	(128)	(105)	(288)	(322)
Expenditures on nuclear waste management	(17)	(15)	(69)	(38)
Expenditures on restructuring	(23)	-	(95)	-
Net changes to other long-term assets and liabilities	(56)	(49)	(129)	(87)
Deferred revenue	(22)	(8)	(29)	(10)
Changes in non-cash working capital balances (note 14)	249	(304)	108	(359)
Cash flow provided by (used in) operating activities	446	(24)	534	177
Investing activities				
Proceeds from Bruce decontrol (note 10)	-	-	-	370
Net proceeds from short-term investments	-	(12)	39	214
Proceeds on sale of decontrol fixed assets (note 10)	-	2	342	12
Cash proceeds from sale of investments (note 11)	15	-	29	-
Purchases of fixed assets	(209)	(181)	(575)	(450)
Cash flow provided by (used in) investing activities	(194)	(191)	(165)	146
Financing activities				
Issuance of long-term debt (note 7)	138	-	138	-
Repayment of long-term debt	(1)	(100)	(1)	(200)
Dividends paid	-	(138)	(134)	(238)
Short-term notes issued	35	-	235	-
Short-term notes repaid	(35)	-	(235)	(50)
Cash flow provided by (used in) financing activities	137	(238)	3	(488)
Net increase (decrease) in cash and cash equivalents	389	(453)	372	(165)
Cash and cash equivalents, beginning of period	(17)	853	-	565
Cash and cash equivalents, end of period	372	400	372	400
Supplementary disclosures				
Interest paid	95	98	191	199
Income taxes paid	-	61	50	132

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)

	September 30 2002	December 31 2001
Assets		
Current assets		
Cash and cash equivalents	372	-
Short-term investments	-	39
Accounts receivable	811	1,010
Income taxes recoverable	11	77
Fuel inventory	577	537
Materials and supplies	54	35
	<u>1,825</u>	<u>1,698</u>
Fixed assets		
Property, plant and equipment	14,735	14,460
Less: accumulated depreciation	1,888	1,479
	<u>12,847</u>	<u>12,981</u>
Other assets		
Deferred pension asset	303	330
Fixed asset removal and nuclear waste management fund (note 8)	1,496	1,208
Long-term note receivable (note 10)	225	225
Materials and supplies	210	179
Long-term accounts receivable and other assets	102	65
	<u>2,336</u>	<u>2,007</u>
	<u>17,008</u>	<u>16,686</u>
Liabilities		
Current liabilities		
Accounts payable and accrued charges (notes 3, 4)	1,660	1,505
Deferred revenue due within one year	13	13
Long-term debt due within one year (note 7)	205	205
	<u>1,878</u>	<u>1,723</u>
Long-term debt (note 7)	<u>3,152</u>	<u>3,015</u>
Other liabilities		
Fixed asset removal and nuclear waste management (note 8)	4,872	4,724
Other post employment benefits	947	924
Long-term accounts payable and accrued charges (notes 4, 10)	335	336
Deferred revenue	176	215
Future income taxes (note 13)	251	279
	<u>6,581</u>	<u>6,478</u>
Shareholder's equity		
Common shares	5,126	5,126
Retained earnings	271	344
	<u>5,397</u>	<u>5,470</u>
	<u>17,008</u>	<u>16,686</u>

See accompanying notes to the consolidated financial statements

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2002 (UNAUDITED)**
(Tabular amounts in million of dollars except as otherwise noted)

1. Basis of Presentation

These interim consolidated financial statements were prepared following the same accounting policies and methods as in the most recent annual consolidated financial statements. However, these financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2001. Certain comparative amounts have been reclassified to conform with the 2002 financial statement presentation.

2. Accounting Policies

Market Power Mitigation Agreement Rebate

OPG is 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 are a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, for the first four years after market opening, a significant majority of OPG's expected energy sales in Ontario are subject to an average annual revenue cap of 3.8¢/kWh. OPG is required to pay a rebate to the IMO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a twelve month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The first settlement period ends April 30, 2003. The quantities of energy subject to the rebate, as well as the hourly weights used to compute the annual average spot price for rebate purposes, have been fixed in advance but may be reduced for decontrol transactions. At each balance sheet date, OPG computes the average spot energy price that prevailed since the beginning of the current settlement period and recognizes a liability if the average price exceeds 3.8¢/kWh.

Energy Contracts for Open Market

OPG is exposed to changes in electricity prices associated with an open spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the price of electricity, OPG has entered 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 over the term of the contract when the underlying hedged transactions occur and are included in generation revenue. All contracts that are not designated as hedges are valued at market value with changes in fair value recorded in energy marketing revenue as gains or losses.

Derivative financial instruments and related risk management products are utilized by the Company in accordance with its Risk Policy and within defined corporate risk tolerances. Transactions may only be initiated with approved counterparties within assigned credit limits and subject to approvals. As a result of these procedures, the Company does not believe the failure of any counter-parties to these derivatives would have a material impact on its operations.

Emission Reduction Credits

OPG utilizes emission reduction credits ("ERCs") to manage acid gas emissions (Nitrogen Oxide, Sulphur Dioxide and Carbon Dioxide) within the prescribed regulatory limits and voluntary limits. ERCs are purchased from trading partners in Canada and the United States. The cost of ERCs are held in inventory and charged to OPG's operations as part of fuel as required. Options to purchase ERC's are accounted for as derivatives and are valued at estimated market value.

Transmission Rights

Transmission rights (“TRs”) are option contracts issued by the IMO that provide protection for importers and exporters against differences between the Ontario market clearing price for energy and the intertie clearing price. Price differences can occur due to limits on transmission capacity between Ontario and the interconnected markets at a specific intertie. OPG purchases TRs in the Ontario market. TRs are accounted for as derivatives used for energy marketing purposes and valued at estimated market value. Changes in fair value are recorded as energy marketing gains or losses.

Taxes

Under the *Electricity Act, 1998*, 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 regulations made under the *Electricity Act, 1998*.

The Company is also required to pay property taxes. OPG makes payments in lieu of property tax on its nuclear and fossil 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.

3. Market Power Mitigation Agreement Rebate

Under OPG’s generating licence, subject to regulatory approval, the Company has the ability to reduce the amount of energy subject to the market power mitigation agreement rebate by the transfer of effective control of certain of its generating facilities to other market participants. As OPG transfers effective control of facilities and meets certain milestones, it can apply to the Ontario Energy Board (“OEB”) for an order determining that the transactions represent the transfer of effective control and thereby eliminate a portion of the market power mitigation agreement rebate obligation (“Decontrol Mitigation”).

In May 2001, OPG completed the agreement to lease its Bruce Nuclear Generating Stations to Bruce Power L.P. and in May 2002, completed the sale of four of its hydroelectric stations located on the Mississagi River to Great Lakes Hydro Income Fund. OPG has filed an application with the OEB seeking a reduction in the amount of energy sales subject to the rebate mechanism as a result of the decontrol of the Bruce Nuclear Generating Stations and is in the process of preparing an application related to the sale of the Mississagi River stations. The Company believes that it has met all of the requirements for the transfer of effective control and therefore will receive a reduction in energy sales subject to the market power mitigation agreement rebate. OEB approval of the applications would result in a reduction in volumes subject to the market power mitigation agreement rebate for the twelve month settlement period ending April 30, 2003 from 101.8 TWh to 81.4 TWh.

Since the average hourly spot price since May 1, 2002 has exceeded the 3.8¢/kWh revenue cap, OPG has recorded a liability at September 30, 2002 equal to the excess of the average hourly spot energy price over 3.8¢/kWh, multiplied by the amount of energy subject to the rebate mechanism. As at September 30, 2002, the Company had deferred 1.779¢/kWh on a volume of 31.7 TWh. The rebate liability was calculated in accordance with the market power mitigation agreement, after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control.

OPG expects to receive a decision from the OEB regarding the Decontrol Mitigation during the first quarter of 2003. If OPG’s application is not approved, revenue in the period in which the determination is made would be decreased by the amount of the Decontrol Mitigation which totalled approximately \$110 million at September 30, 2002.

4. Transition Rate Options

Under a regulation known as Transition – Generation Corporation Rate Options (“TRO”), OPG is required to provide transitional price relief upon market opening to certain large power customers based on the consumption and average price paid by each customer during a reference period from July 1, 1999 to June 30, 2000. The maximum anticipated volume subject to the transitional price relief is approximately 5.4 TWh in the first year after market opening, 3.6 TWh in the second year and 1.8 TWh in each of the third and fourth years. The maximum length of the program is four years, with the possibility that it will expire after only two years if certain decontrol targets are met.

A provision of \$210 million on the TRO contracts was recorded in the first quarter of 2002 related to the future loss on these contracts. The provision was determined using management’s best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on the contracts, interruptions of volume, and the recovery of market power mitigation agreement rebates. These estimates are subject to measurement uncertainty. As a result, it is reasonably possible that actual results experienced may differ materially from the estimated amounts. The provision will be reduced over the term of the contracts based on volume and will be recorded in revenue.

For the three months ended September 30, 2002, \$25 million was charged to the provision. Since market opening on May 1, 2002, the provision has been reduced by \$43 million. At September 30, 2002, the current portion of the provision for loss on these contracts was \$110 million and was included in Accounts Payable and Accrued Charges. The long-term portion of the provision, which was included in Long-Term Accounts Payable and Accrued Charges, was \$57 million.

5. Restatement of 2001 Quarterly Results for Pension and Other Post Employment Benefits

In 2001, OPG changed its policy of accounting for changes in the net actuarial gain or loss for pension and OPEB. This change in accounting policy results in the amortization of the net cumulative unamortized gain or loss in excess of 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets. Previously, the entire change in the net actuarial gain or loss was amortized over employee average remaining service life and plan assets were valued at market for purposes of determining actuarial gains and losses. The change in accounting policy for pensions and OPEB was applied retroactively to April 1, 1999. As a result of this change, the operating results for the nine months ended September 30, 2001 have been restated to reflect an increase in employee benefit expenses of \$25 million and a decrease in net income of \$28 million.

Opening retained earnings at January 1, 2001 were reduced by \$124 million due to the change in accounting policy for pension and OPEB (\$104 million), as well as a revision to OPEB resulting from an assessment of OPG's claims history for 2000 (\$20 million).

6. Restructuring Costs

In 2001, OPG approved a restructuring plan designed to improve OPG’s future competitiveness. The restructuring program relates to an anticipated reduction in the workforce of approximately 2,000 employees over a two to three year period. Restructuring charges of \$67 million and \$210 million were recorded in the fourth quarter of 2001 and the first quarter of 2002, respectively. The restructuring charges included severance costs of \$242 million and related pension and other post employment benefit expenses of \$35 million. Pension and other post employment benefit expenses, recorded as part of restructuring, are included in the deferred pension asset and other post employment benefits on the balance sheet. The provision for severance was increased by \$12 million in the third quarter to record additional severance costs for terminated employees, resulting in total restructuring charges of \$222 million for 2002. The total cost of the restructuring plan is expected to be approximately \$400 million.

The following table provides a summary of the transactions pertaining to the restructuring liability for severance:

	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2002
Balance, beginning of period	170	40
Restructuring charges	12	214
Payments	(23)	(95)
Balance, end of period	159	159

7. Long-term Debt

In March 2002, the Company reached an agreement with the OEFC to defer to December 2004, \$200 million principal amount of senior notes maturing in 2002. In connection with this deferral, the coupon rate on \$100 million principal amount of these notes was increased, based on commercial terms, by 0.50 per cent; the interest rate for the remaining \$100 million principal amount of these notes was unchanged.

During the third quarter of 2002, Brighton Beach Power L.P., a limited partnership between ATCO Power Ltd. and OPG, completed a \$403 million private bond and term debt financing for its 580 megawatt power project under construction in Windsor, Ontario. As of September 30, 2002, \$276 million was outstanding under the loan and accordingly \$138 million is shown on OPG's books. OPG proportionately consolidates its 50 per cent interest in the Brighton Beach Power partnership. If the partnership does not complete the project by September 30, 2006, OPG is required to repurchase its proportionate share of the outstanding debt up to a total of \$201.5 million. OPG is also responsible for contributing its share of equity (up to 10 per cent of project costs) and up to \$12.5 million of cost overruns as necessary.

8. Fixed Asset Removal and Nuclear Waste Management Liabilities

Nuclear Funds Agreements

In March 2002, the Province of Ontario (the "Province") and OPG signed the Ontario Nuclear Funds Agreement (the "Agreement"). The Agreement establishes criteria for the management of segregated funds and limits OPG's financial exposure to the risk of cost increases for certain used fuel liabilities, subject to graduated liability thresholds. Under the terms of the Agreement, OPG will establish two custodial funds that will be held separate from OPG's operations. The Used Fuel Fund will be used to fund future costs of nuclear used fuel waste management. The Decommissioning Fund will be established to fund the future cost of nuclear fixed asset removal and low and intermediate level waste management. The Agreement will become effective when the two custodial funds are established, expected some time during the fourth quarter of 2002.

Since April 1, 1999, OPG has contributed \$1,496 million including interest earned of \$161 million to the nuclear fixed asset removal and nuclear waste management fund. The Decommissioning Fund will be funded through a receivable due from the Ontario Electricity Financial Corporation ("OEFC"), with the balance funded through OPG's existing segregated funds. The remaining segregated funds will be applied to the Used Fuel Fund. OPG will make annual contributions to the Used Fuel Fund of approximately \$450 million to 2008, and a reduced amount over the remaining life of the nuclear generating stations.

OPG will continue to bear the risk and liability for cost increases and fund earnings with respect to nuclear fixed asset removal and low and intermediate level waste management. OPG will also continue to be responsible for the risk and liability for cost increases for used fuel waste management, subject, however, to graduated liability thresholds specified in the agreement which limit OPG's total financial exposure.

As required by the *Nuclear Safety and Control Act* (Canada), and under the terms of the Agreement, the Province will provide to the Canadian Nuclear Safety Commission ("CNSC"), a guarantee that there will be funds available to discharge the nuclear decommissioning and waste liabilities. This guarantee is expected to relate to the portion of the nuclear liabilities not funded by the Decommissioning and Used Fuel funds, or by the OEFC

receivable, and will be determined based on CNSC requirements. The terms and conditions of the guarantee are subject to the approval of the Minister of Finance.

In June 2002, the *Nuclear Fuel Waste Act* (Canada) received Royal Assent. Under the Act, owners of nuclear fuel waste are required to form a waste management organization to address and provide recommendations on long-term management of nuclear fuel waste. In addition, under the Act, OPG will be required to make an initial deposit of \$500 million into a trust fund within ten days of the Act coming into force and \$100 million for each of the three years thereafter. The Company will provide such funds by way of transfer from existing segregated funds and from its annual contributions to segregated funds. The Act will come into effect when proclaimed into force, which is expected in the fourth quarter of 2002.

Cost Estimate Changes Made in 2002

OPG reviewed the significant assumptions that underlie the calculation of the accrued liabilities for fixed asset removal and nuclear waste management liabilities. As a result of this review, a number of assumptions were revised to reflect changes in the timing of certain programs and in the evolving technology used to handle the nuclear waste. These changes included a delay in the in-service date for used nuclear fuel disposal facilities from 2025 to 2035, the recognition of certain costs associated with dry storage of used nuclear fuel during station operating life, and recognition of additional costs related to nuclear waste management programs. In aggregate, these cost estimate changes would result in a net reduction to the nuclear waste management and decommissioning liability of \$215 million. In accordance with Canadian generally accepted accounting principles, the change in liability is being amortized over the average remaining service life of the nuclear generating stations. As a result of this change, for the nine months ended September 30, 2002, \$12 million was recorded as a decrease to the liability and a reduction to expenses.

9. Derivative Financial Instruments

The tables below provide a summary of the fair value of OPG's derivative instruments. The first table relates to derivative instruments that are not hedges. These derivatives are carried on the balance sheet as assets or liabilities at fair value, with changes in fair value recognized in energy marketing revenue.

The second table relates to derivative instruments designated as hedges. The Company uses financial commodity derivatives primarily to fix the price for electricity sales. Gains or losses on these derivative hedging instruments are recognized in income over the term of the contract when the underlying transactions occur and are not recorded on the balance sheet.

The Company uses foreign exchange derivative instruments primarily to hedge its net exposure to anticipated US dollar denominated purchases. Foreign exchange translation gains and losses on these foreign currency denominated financial instruments are recognized as an adjustment to the purchase price of the commodity or goods received.

Fair values have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG develops internal models for prices, based on available market data. The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized over the term of the contract when the underlying transactions occur.

	September 30, 2002		December 31, 2001
	Notional Quantity	Fair Value	Fair Value
Carrying amount (fair value) of contracts not used for hedging purposes			
Commodity derivative instruments			
Assets	10.8 TWh	3	-
Liabilities	2.9 TWh	(15)	-
Total		(12)	-

At September 30, 2002, the fair value of commodity derivative instruments not used for hedging purposes consists of a \$12 million liability related to legacy contracts from the previous market structure, and transmission rights and other short-term contracts with a fair value of nil. The income statement impact of these transactions was reduced by the reversal, upon market opening, of a contract loss provision recorded as at December 31, 2001.

	September 30, 2002			December 31, 2001		
	Notional quantity	Terms	Fair Value	Notional quantity	Terms	Fair Value
Fair value of derivative contracts designated as hedges						
Commodity derivative instruments						
Electricity	44 TWh	1-5 yrs	86	14 TWh	1-5 yrs	-
Foreign exchange derivative instruments	\$229 US	Apr/03	6	\$147 US	Mar/02	3
Option to purchase emission reduction credits	2,000,000 tonnes	2003-2004	-	-	-	-

10. Decontrol Initiatives

Bruce Nuclear Generating Stations

In May 2001, the Company completed the close of the operating lease agreement to lease its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with an option to renew for 25 years. As part of the initial payment, OPG received \$370 million in cash proceeds and a \$225 million note receivable. The receivable of \$225 million is payable to OPG in two installments of \$112.5 million no later than four and six years from the date the transaction was completed. Interest is currently charged on the initial payment at a rate of 10.5 per cent, escalating over time to 18 per cent annually. The interest is recorded as non-energy revenue.

Under the terms of the lease, OPG agreed to transfer certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. OPG also agreed to transfer pension assets and liabilities related to the approximately 3,000 employees who transferred from OPG to Bruce Power. Bruce Power assumed the liability for other post employment benefits for these employees. OPG will pay Bruce Power, in respect of other post employment benefits, payments of approximately \$2.3 million per month over a 72-month period ending in 2008.

As part of the closing, OPG recorded \$230 million of deferred revenue to reflect the initial payment less net assets transferred to Bruce under the lease agreement. The deferred revenue is being amortized over the initial lease term of approximately 18 years and is recorded as non-energy revenue.

During the third quarter ended September 30, 2002, OPG and Bruce Power settled certain remaining outstanding matters related to the lease of the Bruce Nuclear Generating Stations totalling \$22 million. For the nine months ended September 30, 2002, total post closing adjustments with respect to this transaction were \$29 million.

As part of the lease agreement, OPG receives annual lease payments from Bruce Power. The lease payments consist of monthly fixed payments and supplemental payments based on the number of operating units. The supplemental lease payment structure has been modified, with effect from May 2001, to replace the original net revenue-sharing arrangement. The lease payments are made semi-annually and are recorded in non-energy revenue.

Bruce Power's parent Company, British Energy PLC, is experiencing financial difficulties which could impact on Bruce Power's liquidity and operations. OPG is closely monitoring the situation. At September 30, 2002, OPG had a note receivable from Bruce Power of \$225 million, accounts receivable of approximately \$61 million and long-term liabilities and other payables due to Bruce Power of approximately \$136 million and \$38 million respectively. Management believes that its security interest and the rights under the lease arrangements, including repossession rights, minimize OPG's potential financial exposure to a default by Bruce Power or British Energy.

Decontrol of Mississagi River Stations

In March 2002, OPG announced the sale of four hydroelectric generating stations located on the Mississagi River, to Great Lakes Hydro Income Fund. The sale closed on May 17, 2002. OPG received cash proceeds of \$342 million from the sale and recorded a pretax gain of \$99 million.

Other Decontrol Activities

OPG continues to evaluate options for decontrol of stations and is committed to meet its obligations under the market power mitigation agreement. The process for meeting decontrol of price-setting generation has been impacted by the current market conditions in the energy sector. The amounts that OPG will ultimately realize with respect to these potential transactions could differ materially from the carrying values recorded in the financial statements.

11. Other Income

Other income is comprised of the gain on sales from decontrol activities and other initiatives as follows:

	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2002	2001	2002	2001
Mississagi River generating stations	-	-	99	-
Investment in Kinectrics Inc.	-	-	3	-
Investment in New Horizon Systems Solutions Inc.	-	-	4	-
Nuclear Safety Assessment Division	11	-	11	-
	11	-	117	-

Sale of Investment in Kinectrics Inc.

In February 2002, OPG sold its remaining ownership interest in Kinectrics Inc. to AEA Technology plc for approximately \$12 million in cash proceeds. The Company recorded a gain on the sale of Kinectrics of \$3 million.

Sale of Investment in New Horizon Systems Solutions Inc.

In March 2002, OPG divested its 49 per cent joint venture interest in New Horizon System Solutions Inc. ("New Horizon") to Business Transformation Services Inc., a wholly owned subsidiary of Cap Gemini Ernst & Young. OPG entered into a nine-year information technology outsourcing agreement with New Horizon in order to continue to gain access to a broad spectrum of IT services in infrastructure and operations management. The Company recorded a gain on sale of \$4 million.

Sale of Nuclear Safety Assessment Division

During the third quarter 2002, the Company completed the sale of its Nuclear Safety Analysis Division to Nuclear Safety Systems, a subsidiary of National Nuclear Corporation. Total proceeds from the sale were approximately \$20 million consisting of cash proceeds of approximately \$15 million and assumption of other liabilities of approximately \$5 million. The Company recorded a gain of approximately \$11 million.

12. Other Items

WSIB Settlement

For purposes of the Worker's Safety and Insurance Board of Ontario ("WSIB"), OPG was reclassified from a schedule 2 self-insured employer to a schedule 1 premium-paying employer. During the third quarter, the WSIB assumed the liability with respect to OPG's existing and future worker's compensation claims in exchange for a cash payment of \$54.5 million. Accordingly a settlement of the entire obligation has occurred and the Company recorded a one-time reduction in OM&A expenses of \$24 million.

13. Income Taxes

For the nine-month period ended September 30, 2002, the effective income tax rate increased to 49 per cent in 2002 from 37 per cent in 2001. The 2001 tax rate was lower primarily due to the one-time impact of the reduction in future taxes resulting from the decrease in the future income tax rates announced last year. The 2001 third quarter results reflected a reduction in the effective income tax rate as a result of favourable income tax treatment for certain other revenues that arose in 2001.

14. Changes in Non-Cash Working Capital Balances

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	2002	2001
Accounts receivable	(388)	23	201	155
Income tax recoverable	143	-	66	-
Fuel inventory	8	(79)	(40)	(77)
Materials and supplies	-	2	(19)	(57)
Accounts payable and accrued charges	486	(250)	(100)	(380)
	249	(304)	108	(359)

15. Segment Disclosures

Description of Reportable Segments

With the opening of Ontario's electricity market to competition on May 1, 2002, OPG began operating a second reportable business segment referred to as the Energy Marketing segment. OPG now has two reportable segments: Generation and Energy Marketing. OPG also derives non-energy revenue under the terms of the lease arrangement with Bruce Power, including lease revenue, interest income and revenue from engineering analysis and design, technical and ancillary services. Non-energy revenue also includes isotope sales and gains and losses from decontrol activities.

Generation Segment

OPG's principal business segment operates in Ontario generating and selling electricity. Commencing May 1, 2002, all of OPG's electricity generation is sold into the IMO-administered real-time energy spot market. As such, the majority of OPG's revenue is derived from spot market sales. In addition to revenue earned from spot market sales, revenue is also earned through offering available capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, black start capability and automatic generation control. Prior to market opening, OPG sold electricity directly to wholesale electricity customers in Ontario and to interconnected markets in Quebec, Manitoba and the U.S. northeast and midwest.

Energy Marketing Segment

The Energy Marketing segment derives revenues from various financial and physical energy market transactions with large volume end-use customers and intermediaries such as utilities, brokers, aggregators, traders and other power marketers and retailers. Energy marketing in deregulated markets includes spot market sales and trading, the sale of bilateral risk management products and sales of energy-related products and services to meet customers' needs for energy solutions. The results of transactions in derivatives not designated as hedges of energy prices are included in the Energy Marketing segment. OPG also markets and sells electricity into the interconnected markets of other provinces and the U.S. northeast and midwest. Previously, OPG's energy marketing activity was not a reportable business segment. Accordingly, there are no comparative values for 2001.

Reported Segment Income

3 months ended September 30, 2002				
	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	1,504	67	77	1,648
Fuel	412	-	-	412
Power purchased	-	36	-	36
Gross margin	1,092	31	77	1,200
Operation, maintenance and administration	569	1	11	581
Depreciation and amortization	153	-	35	188
Property and capital taxes	26	-	3	29
Restructuring costs	-	-	12	12
Operating income (loss)	344	30	16	390
Other income	-	-	11	11
Net interest expense	-	-	36	36
Income before income taxes	344	30	(9)	365

3 months ended September 30, 2001				
	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	1,553	-	82	1,635
Fuel	393	-	-	393
Power purchased	374	-	-	374
Gross margin	786	-	82	868
Operation, maintenance and administration	579	-	24	603
Depreciation and amortization	179	-	23	202
Property and capital taxes	-	-	2	2
Operating income (loss)	28	-	33	61
Net interest expense	-	-	31	31
Income before income taxes	28	-	2	30

9 months ended September 30, 2002	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	4,160	86	240	4,486
Fuel	1,147	-	-	1,147
Power purchased	290	54	-	344
Gross margin	2,723	32	240	2,995
Operation, maintenance and administration	1,747	3	43	1,793
Depreciation and amortization	486	-	80	566
Property and capital taxes	79	-	9	88
Restructuring costs	-	-	222	222
Loss on transition rate option contracts	-	-	210	210
Operating income (loss)	411	29	(324)	116
Other income	-	-	117	117
Net interest expense	-	-	114	114
Income (loss) before income taxes	411	29	(321)	119

9 months ended September 30, 2001	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	4,521	-	160	4,681
Fuel	1,099	-	-	1,099
Power purchased	649	-	-	649
Gross margin	2,773	-	160	2,933
Operation, maintenance and administration	1,818	-	43	1,861
Depreciation and amortization	566	-	40	606
Property and capital taxes	43	-	3	46
Operating income (loss)	346	-	74	420
Net interest expense	-	-	102	102
Income before income taxes	346	-	(28)	318

Selected Balance Sheet Information

September 30, 2002				
Segment property, plant & equipment	11,909	-	938	12,847
December 31, 2001				
Segment property, plant & equipment	12,026	-	955	12,981

Selected Cash Flow Information

3 months ended September 30, 2002				
Capital expenditures	209	-	-	209
3 months ended September 30, 2001				
Capital expenditures	180	-	1	181
9 months ended September 30, 2002				
Capital expenditures	575	-	-	575
9 months ended September 30, 2001				
Capital expenditures	447	-	3	450

16. Seasonal Operations

The Company's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, the Company'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 market power mitigation agreement rebate and the Company's hedging strategies significantly reduce the impact of seasonal price fluctuations on the Company's operations.

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
www.sedar.com