ONTARIO POWER GENERATION

News from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2002 SECOND QUARTER EARNINGS

[Toronto]: Ontario Power Generation Inc. (OPG) today reported its financial and operating results for the second quarter and first six months ended June 30, 2002. Earnings for the three months ended June 30, 2002 were $63 million or $0.25 per share, as compared with second quarter earnings in 2001 of $17 million or $0.07 per share. For the six months ended June 30, 2002 the loss was $154 million or $0.60 per share compared to earnings of $119 million or $0.46 per share for the same period last year.

"OPG's second quarter earnings primarily reflect a gain on sale of the four hydroelectric stations on the Mississagi River, offset in part by the impact of lower energy prices since market opening. Our six month results reflect a loss primarily due to restructuring charges and a provision on transition rate option contracts for industrial customers taken in the first quarter," said OPG President and CEO, Ron Osborne.

OPG's generating stations continued to perform well during the second quarter, particularly the nuclear generating stations which achieved a net capacity factor of 85.7 per cent for the three months ended June 30, 2002 compared to 73.2 per cent for the same period last year. For the six months ended June 30, 2002, the net capacity factor was 87.6 per cent compared to 82.0 per cent last year.

"On May 1, 2002, Ontario's electricity market opened to competition at the wholesale and retail levels. We are pleased with the transition to a competitive market environment and look forward to successfully competing in Ontario's reregulated electricity industry. The dynamics of the electricity market will continue to evolve with all participants developing a better understanding of market forces," said Osborne.

During the second quarter, OPG completed the sale of four Mississagi hydroelectric stations to Great Lakes Hydro Income Fund; obtained its Federal Energy Regulatory Commission (FERC) licence to market electricity directly to end-use customers in the U.S. effective May 1, 2002; and continued to improve nuclear performance.

In May, Dominion Bond Rating Service lowered OPG’s senior unsecured long-term debt rating to A (low) with a stable trend from A, while affirming its short-term debt rating of R-1 (low). In July, Standard and Poor’s reaffirmed OPG’s long-term debt rating of BBB+ while changing the outlook to negative and lowering the short-term debt rating to A-2 (Cdn) from A-1 (low).

Ontario Power Generation is an Ontario based company, whose principal business is the generation and sale of electricity to customers in Ontario and to interconnected markets. OPG's goal is to be a premier North American energy company, while operating in a safe, open and environmentally responsible manner. Our focus is on producing reliable electricity from our competitive generation assets; power trading; and commercial energy sales activities.

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

SECOND QUARTER 2002 RESULTS

This discussion and analysis should be read in conjunction with the unaudited consolidated financial statements and accompanying notes of OPG for the three and six months ended June 30, 2002. It should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes and Management's Discussion and Analysis for the year ended December 31, 2001. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles and are presented in Canadian dollars.

BUSINESS SEGMENTS

Commencing May 1, 2002, upon opening of the Ontario electricity market to competition, OPG began operating two business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, includes revenue and corporate costs which are not allocated to the two business segments.

With the opening of the Ontario electricity market to competition on May 1, 2002, all of OPG's electricity generation is sold into the real-time energy spot market administered by the Independent Electricity Market Operator ("IMO"), in order to be dispatched by the IMO. As such, the majority of OPG's revenue is derived 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, including local distribution companies and large industrial customers, and to customers in the interconnected markets of Quebec, Manitoba and the northeast and midwest regions of the United States.

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 an open spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation portfolio are included in the Generation segment activities.

The Energy Marketing segment includes spot market sales and trading, and the sale of risk management and other energy-related products and services to meet customers' needs for energy solutions. OPG also sells and purchases into and from the interconnected markets of other provinces and the U.S. northeast and midwest. All contracts that are not designated as hedges are valued at market value with changes in fair value recorded in energy marketing revenue as trading gains or losses.

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 revenue, interest income and revenue from engineering analysis and design, technical and ancillary services. Non-energy revenue also includes isotope sales to the medical industry. Corporate groups including human resources, finance, legal, treasury, information systems and other administrative services provide support to the reportable business segments.

HIGHLIGHTS

(millions of dollars unless otherwise stated)	**Three Months Ended June 30** **2002**	**2001**	**Six Months Ended June 30** **2002**	**2001**
Revenues	**1,288**	1,507	**2,845**	3,046
Net income (loss)	**63**	17	**(154)**	119
Earnings (loss) per common share ($ per common share)	**0.25**	0.07	**(0.60)**	0.46
Cash flow provided by (used in) operating activities	**(39)**	118	**88**	201
Total physical electricity sales volume (TWh)				
Generation segment	**30.0**	33.7	**66.3**	70.8
Energy marketing segment	**0.4**	-	**0.4**	-
Total	**30.4**	33.7	**66.7**	70.8
Total energy available (TWh)				
Total production	**28.0**	30.0	**58.8**	65.8
Purchased power	**2.3**	4.3	**8.0**	5.8
Other *	**0.1**	(0.6)	**(0.1)**	(0.8)
Total	**30.4**	33.7	**66.7**	70.8

*Represents deposits and withdrawals of electricity with utilities in neighbouring jurisdictions under energy banking arrangements

For the three months ended June 30, 2002, OPG had net income of $63 million compared with net income of $17 million for the same period in 2001. For the six months ended June 30, 2002, OPG had a net loss of $154 million compared with net income of $119 million for the same period last year, a decrease of $273 million. Significant factors impacting earnings in 2002 compared to 2001 included the following:

Change in Earnings – 2002 compared to 2001 (millions of dollars – after tax)	**Three Months Ended June 30, 2002**	**Six Months Ended June 30, 2002**
Lower energy prices after market opening on May 1	(56)	(56)
Gain on sale of Mississagi River stations	79	79
Restructuring charge for costs related to a reduction in workforce	-	(134)
Loss on Transition Rate Option contracts for industrial customers after market opening	-	(137)
Higher activity levels and expenditures related to the return to service of the Pickering A nuclear generating station	(20)	(57)
Impact of decontrol – decrease in gross margin partially offset by OM&A and other savings	(8)	(32)
Decrease in OM&A expenses due in part to lower nuclear outage costs and completion of nuclear recovery programs	6	17
Other including impact of higher nuclear and hydroelectric production, lower power purchased and lower depreciation and amortization	45	47
Increase (decrease) in earnings	46	(273)

DISCUSSION OF SEGMENTED RESULTS

Generation

(millions of dollars)	Three Months Ended June 30 2002	2001	Six Months Ended June 30 2002	2001
Revenue	**1,186**	1,458	**2,656**	2,968
Fuel	**332**	338	**731**	706
Power purchased	**75**	173	**294**	275
Gross margin	**779**	947	**1,631**	1,987
Operation, maintenance and administration	**604**	613	**1,178**	1,239
Depreciation and amortization	**156**	164	**306**	346
Property and capital taxes	**14**	12	**30**	25
Operating income	**5**	158	**117**	377

Gross Margin

The gross margin from electricity sales in the Generation segment was $779 million for the second quarter of 2002 compared to $947 million for the same period in 2001. The gross margin for the six months ended June 30, 2002 was $1,631 million compared to $1,987 million for the same period last year. The most significant factor contributing to the decrease in gross margin for both the second quarter and six month period was the impact of the decontrol of the Bruce nuclear generating stations. On May 11, 2001, OPG completed the agreement to lease its Bruce nuclear generating stations to Bruce Power. Under the terms of the operating lease agreement, OPG was required to purchase electricity from Bruce Power up to the date of market opening, which reduced OPG's gross margin. Other factors that contributed to the decrease in gross margin included lower prices subsequent to market opening on May 1, 2002 and higher coal prices, partially offset by lower power purchases from sources other than Bruce Power due to higher production from OPG's generating stations.

(millions of dollars)	Three Months Ended June 30 2002	2001	Six Months Ended June 30 2002	2001
Spot market sales	**638**	-	**638**	-
Electricity sales (prior to market opening)	**494**	1,432	**1,939**	2,917
Financial transactions (sales contracts)	**30**	-	**30**	-
Other	**24**	26	**49**	51
Total generation revenue	**1,186**	1,458	**2,656**	2,968

Generation revenue was $1,186 million for the three months ended June 30, 2002 compared to revenue of $1,458 million for the same period in 2001, a decrease of $272 million. For the six months ended June 30, 2002, generation revenue was $2,656 million, a decrease of $312 million compared to revenue of $2,968 million for the same period last year. The decrease in generation revenue was due to both lower electricity sales prices and lower volumes. The net reduction in average price has contributed to a decrease in both second quarter and year to date revenue of $94 million compared to last year.

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, including a rebate mechanism. Under the rebate mechanism, for the first four years after market opening, a majority of OPG's expected energy sales in Ontario are subject to an average annual revenue cap of 3.8 cents/kWh. OPG is required to pay a rebate to the IMO for ultimate distribution to customers equal to the excess, if any, of the average hourly spot energy price over 3.8 cents/kWh for the amount of energy sales subject to the rebate mechanism. Given that the average spot market prices were less than 3.8 cents/kWh, there was no rebate accrued as at June 30, 2002.

Electricity sales volumes for the second quarter ended June 30, 2002 were 30.0 TWh, compared to 33.7 TWh for the same period last year. For the six months ended June 30, 2002, electricity sales were 66.3 TWh compared to 70.8 TWh last year. The decrease in volumes was primarily due to lower sales related to generation from the Bruce nuclear generating stations. Upon the closing of the operating lease agreement with Bruce Power, OPG was obligated to purchase and resell all of Bruce Power's electricity generation up to the date of market opening. With market opening, Bruce Power now sells electricity directly into the IMO-administered real-time energy market, lowering OPG's sales revenue and volumes.

Fuel expense for the second quarter of 2002 was $332 million compared to a fuel expense of $338 million for the same period in 2001. The decrease of $6 million was primarily due to lower production at OPG's fossil-fuelled generating stations, largely offset by higher coal prices and an increase in the Gross Revenue Charge ("GRC") as a result of higher hydroelectric production. The GRC was introduced by the Province of Ontario effective January 1, 2001 to restructure the payment of municipal property taxes, water rentals and payments in lieu of property taxes from OPG's hydroelectric generating stations. The GRC payments are set based on the gross revenue derived from the annual generation of electricity from these hydroelectric generating stations and are dependent on both energy prices and hydroelectric production.

Fuel expense for the first six months of 2002 was $731 million compared to $706 million in 2001. The increase was due to higher coal prices and GRC amounts, largely offset by the lower production at the fossil-fuelled generating stations.

Power purchased during the second quarter 2002 was $75 million compared with $173 million for the same period in 2001. Power purchased in the second quarter of 2002 was 1.9 TWh compared with 4.3 TWh for the same period last year. The decrease was primarily due to the elimination of purchases from Bruce Power subsequent to market opening. Power purchased from Bruce Power during the second quarter of 2002 for the period April 1 to April 30, 2002 was 1.7 TWh, compared with 3.7 TWh during the second quarter of 2001, related to the period from May 11 to June 30, 2001.

Power purchased during the first six months of 2002 was $294 million compared with $275 million for the same period in 2001, based on purchases of 7.6 TWh in 2002 and 5.8 TWh in 2001. The increase was primarily due to higher purchases of electricity from Bruce Power. OPG purchased 6.8 TWh of electricity from Bruce Power during the period from January 1 to April 30, 2002, compared to 3.7 TWh from May 11 to June 30, 2001. This increase was partially offset by lower purchases from other sources in 2002 due to increased production from OPG's generating stations.

Total Energy Available (TWh)	Three Months Ended June 30		Six Months Ended June 30	
	2002	**2001**	**2002**	**2001**
Production				
Nuclear:				
Darlington & Pickering	**10.5**	9.0	**21.3**	20.0
Bruce (1)	**-**	2.3	**-**	8.6
Total Nuclear	**10.5**	11.3	**21.3**	28.6
Fossil	**7.4**	9.7	**18.1**	20.0
Hydroelectric	**10.1**	9.0	**19.4**	17.2
Total Production	**28.0**	30.0	**58.8**	65.8
Power Purchased (2)	**1.9**	4.3	**7.6**	5.8
Other (3)	**0.1**	(0.6)	**(0.1)**	(0.8)
Total Energy Available	**30.0**	33.7	**66.3**	70.8

(1) Represents generation from Bruce nuclear generating stations prior to decontrol.
(2) OPG had a commitment to purchase all of Bruce Power's electricity generation up to May 1, 2002, the date of market opening, as part of the lease agreement for the Bruce nuclear generating stations.
(3) Represents deposits and withdrawals of electricity with utilities in neighbouring jurisdictions under energy banking arrangements.

Operating Expenses

Operation, maintenance and administration (OM&A) expenses were $604 million for the second quarter of 2002 compared with $613 million for the same period in 2001. OM&A expenses were impacted by a reduction in operating costs resulting from the decontrol of the Bruce nuclear generating stations in May 2001 ($30 million), increased activity and expenditures related to the return to service of the Pickering A nuclear generating station ($34 million) and other decreases in expenses ($13 million).

OM&A expenses were $1,178 million for the six months ended June 30, 2002 compared with $1,239 million for the same period in 2001. The decrease in OM&A expenses for the six-month period was mainly due to reduced operating expenses from the decontrol of the Bruce nuclear generating stations ($112 million) and a decrease in other expenses primarily due to lower nuclear outage costs and completion of nuclear recovery programs ($44 million). This decrease was partially offset by higher expenditures related to the return to service of the Pickering A nuclear generating station ($95 million).

Energy Marketing

Since May 2002, OPG has transacted with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities ranging from one day to one year. These activities related primarily to physical energy, but also included financial products to manage the financial risk of the physical transactions. Previously, OPG's energy marketing activity was not a reportable business segment. Accordingly, there are no comparative amounts for 2001.

	Six Months Ended June 30	
(millions of dollars)	**2002**	**2001**
Revenue	**19**	-
Power purchased	**18**	-
Gross margin	**1**	
Operation, maintenance and administration	**2**	-
Operating loss	**(1)**	-

OPG has implemented comprehensive trade capture and risk management systems and processes to identify and measure risk related to energy marketing activities. Appropriate position and risk limits have been established for performance and risk management purposes.

Non-Energy and Other

(millions of dollars)	Three Months Ended June 30 2002	2001	Six Months Ended June 30 2002	2001
Revenue	**83**	49	**170**	78
Operation, maintenance and administration	**14**	13	**32**	19
Depreciation and amortization	**37**	44	**72**	58
Property and capital taxes	**14**	16	**29**	19
Restructuring costs	**-**	-	**210**	-
Loss on transition rate option contracts	**-**	-	**210**	-
Gain on sale of fixed assets	**(99)**	-	**(99)**	-
Net interest expense	**39**	37	**78**	71

Revenue

Non-energy revenue was $83 million for the second quarter of 2002 compared to $49 million for the same period last year. Non-energy revenue for the six months ended June 30, 2002 was $170 million compared to revenue of $78 million for the same period in 2001. The increase in non-energy revenue was primarily due to the lease and ancillary revenue earned under the agreements with Bruce Power. Isotope sales for the six months ended June 30, 2002 were $9 million compared to $12 million for the same period last year.

Restructuring Costs

In 2001, OPG approved a restructuring plan designed to improve OPG's future cost competitiveness. Completion of significant decontrol activities and completion of other major initiatives over the next two years requires the restructuring of areas within OPG that support these operations. Restructuring charges are related to an anticipated reduction in the workforce of approximately 2,000 employees over a two to three year period. During the first quarter of 2002, voluntary severance packages for approximately 1,200 employees were accepted.

Restructuring charges include severance costs and related pension and other post employment benefit expenses. The provision for restructuring costs recorded in the first quarter of 2002 was $210 million. This amount is in addition to a restructuring charge of $67 million recorded in the fourth quarter of 2001. The total cost of the restructuring plan is expected to be approximately $400 million. During the second quarter of 2002, there were payments of $64 million related to restructuring.

Loss on 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 rebates. These estimates are subject to measurement uncertainty. Since the market opened on May 1, 2002, $18 million has been charged against the provision and included in generation revenue.

Gain on Sale of Fixed Assets

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

INCOME TAX

For the six month period ended June 30, 2002, the effective income tax rate decreased to 37.4 per cent from an effective income tax rate of 58.6 per cent in 2001. The decrease in the effective income tax rate was primarily due to the impact of Large Corporations Tax expense, which reduced the amount of the income tax recoverable in 2002.

RESTATEMENT OF SECOND QUARTER 2001 FOR PENSIONS AND OTHER POST EMPLOYMENT BENEFITS (OPEB)

At year-end 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 amortization of the net cumulative unamortized gain or loss in excess of 10% 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 the 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 six months ended June 30, 2001 have been restated to reflect an increase in employee benefit expense of $51 million and a decrease in net income of $46 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow used in operating activities for the second quarter ended June 30, 2002 was $39 million compared to cash flow provided from operating activities of $118 million in same period in 2001, a reduction in cash flow of $157 million. The decrease in cash flow from operating activities was mainly due to expenditures for restructuring and changes in non-cash working capital.

Cash flow provided from operating activities for the six months ended June 30, 2002 was $88 million compared to $201 million for the same period in 2001. The decrease in cash flow provided by operating activities was mainly due to expenditures for restructuring and changes in non-cash working capital, partially offset by lower contributions to the fixed asset removal and nuclear waste management fund.

With market opening, electricity prices are expected to have seasonal variations related to changes in demand. Prices are expected to be 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.

During the six months ended June 30, 2002 the fixed asset removal and nuclear waste management fund increased by a total of $160 million compared to $217 million for the same period in 2001. OPG made lower contributions in 2002 in order to adjust for overcontributions in previous years. The balance in the fund at June 30, 2002 was $1,368 million.

Capital expenditures for the second quarter were $210 million compared to $154 million for the same period in 2001. For the six-month period ended June 30, 2002, capital expenditures were $366 million compared to $269 million for the same period last year. The increase in capital expenditures was primarily due to higher activity related to the return to service of the Pickering A nuclear generating station and expenditures related to the installation of selective catalytic reduction equipment associated with emission reductions at OPG's Lambton and Nanticoke fossil generating stations.

OPG is progressing with the safety and environmental upgrades and other refurbishment work which is required prior to the return to service of the four units at the Pickering A nuclear generating station. To date, expenditures on the return to service initiative total approximately $880 million, the majority of which has been expensed.

OPG expects to begin commissioning the first of the four units at the Pickering A nuclear generating station towards the end of 2002. The estimated additional cost to complete the first unit is $120 million. The remaining three units are estimated to be returned to service at an additional cost of approximately $300 million to $400 million per unit. Pickering A will add 2,060 MW of reliable, low cost electricity and will make a significant contribution towards improving environmental performance within the Ontario electricity sector.

In March 2002, OPG renewed its revolving short-term committed credit facility. The amount of the credit facility was increased from $600 million to $1,000 million. The credit facility can be extended for a two-year term. Notes issued under the Company's Commercial Paper ("CP") program are supported by this credit facility. At June 30, 2002, OPG had no amounts outstanding under the CP program. OPG is planning to access the long-term debt market during the fourth quarter of 2002.

In May 2002, Dominion Bond Rating Service lowered OPG's senior unsecured long-term debt rating to A (low) from A while confirming the Commercial Paper rating of R-1 (low). The trend on both ratings remains stable. In July 2002, Standard and Poor's reaffirmed OPG's long-term debt rating of BBB+ while changing the outlook to negative and lowering the short-term debt rating to A-2 from A-1(low).

The Company paid dividends of $134 million during the six months ended June 30, 2002 compared with $100 million for the same period in 2001. The increase in dividends reflected a dividend related to proceeds received from the decontrol of the Bruce nuclear generating stations and other dividends to achieve a 35 per cent pay out of actual 2001 earnings.

RISK MANAGEMENT

Ontario's electricity market opened to competition on May 1, 2002. With market opening, OPG is subject to increased risk, including market and credit risk inherent in a deregulated market. The Board of Directors has approved governance policies and structures to facilitate the management of the increased risk. A Risk Oversight Committee, which consists of senior officers of OPG, has been established to approve products, monitor policies and compliance issues, and ensure the continuing effectiveness of overall corporate governance under the direction of the Board of Directors.

In anticipation of increased levels of risk and complexity of market activities, OPG implemented a comprehensive trade capture and risk management system with related processes and controls. OPG's commercial activities are separated into portfolios to capture the risks inherent in each transaction for each portfolio. This process facilitates the effective identification and measurement of risks, and the application of appropriate position and risk limits for performance and risk management purposes. The methodology used to measure these risks includes the use of consistent and recognized risk measures for monitoring trading activities and the generation portfolio. Open positions are subject to measurement against value at risk ("VaR") limits, which measure the potential loss in a portfolio's market value due to market volatility over a one day holding period, with a 95% confidence interval.

Electricity Price Risk

Electricity price risk is the risk that changes in the market price of electricity will adversely impact OPG's earnings and cash flow from operations. OPG faces price risk directly related both to the demand and supply of generation in the open market and transmission constraints. OPG's production is exposed to spot market prices. However, derivative instruments and related risk management products may be used to mitigate OPG's exposure to volatile electricity prices.

Credit Risk

Credit risk is the risk of non-performance by contractual counterparties. With an open market, substantially all of OPG's revenues are derived from sales through the IMO-administered spot market. Participants in the IMO spot market must meet IMO-mandated standards for creditworthiness. Other revenues are derived from several sources, including the sale of financial risk management products to third parties.

OPG actively manages credit risk through an established counterparty credit policy, and has implemented credit evaluation and collection procedures to monitor its credit exposures. OPG manages counterparty credit risk by monitoring and limiting its exposure to counterparties with lower credit ratings, evaluating its counterparty credit exposure on an integrated basis, and by performing periodic reviews of the credit-worthiness of all counterparties, including obtaining credit security for all transactions beyond approved limits.

Generation Risk

OPG is exposed to the market impacts of uncertain output from its generating units or generation risk. The amount of electricity generated by OPG is affected by such risks as 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 licencing of its nuclear facilities, and manages environmental constraints utilizing programs such as emission reduction credits to manage the supply of generation.

Liquidity Risk

OPG operates in a capital-intensive business and its initiative to return its Pickering A station back to service requires significant financial resources. Furthermore, any acquisition or development projects may require access to capital from outside sources on acceptable terms. OPG may also require external financing to fund capital expenditures necessary to comply with air emission or other regulatory requirements.

OPG's ability to arrange debt financing and the costs of debt capital are dependent on a number of factors including: general economic and capital market conditions; credit availability from banks and other financial institutions; maintenance of acceptable credit ratings; and the status of electricity market deregulation in Ontario.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange risk exposure is attributable primarily to U.S. dollar-denominated transactions such as the purchase of fossil fuel and the purchase and sale of electricity in U.S. markets. OPG currently manages its exposure by periodically hedging portions of its U.S. dollar cash flows according to approved risk management policies.

Interest rate exposure for OPG is limited by the fixed rates on its long-term debt. 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.

COMPARATIVE FIGURES

In 2001, the Province of Ontario introduced a Gross Revenue Charge derived from the annual generation of electricity from hydroelectric generating stations. In the second quarter of 2002, OPG has classified all of the GRC payments as fuel expense. Previously, GRC expenses were charged to fuel expense and property tax expense. As a result of this change, $38 million has been reclassified for comparative purposes as fuel expense from property tax expense for the second quarter of 2001. For the six months ended June 30, 2001, $91 million has been reclassified for comparative purposes to fuel expense from property tax expense.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this press release are forward-looking and reflect the Company's views with respect to future events. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Forward-looking statements are not guarantees of the Company's future performance or results and are subject to various factors, including, but not limited to, assumptions regarding the nuclear recovery plan, nuclear waste management and decommissioning, fuel procurement, fuel costs, Ontario electricity industry restructuring, market power mitigation, environmental regulations, spot market electricity prices, and effects of weather. Although the Company believes that assumptions inherent in forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of their dates. The Company is not obligated to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise.

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)

	Three Months Ended June 30	Restated *(note 5)*	Six Months Ended June 30	Restated *(note 5)*
	2002	**2001**	**2002**	**2001**
Revenues	**1,288**	1,507	**2,845**	3,046
Fuel *(note 2)*	**332**	338	**731**	706
Power purchased	**93**	173	**312**	275
Gross Margin	**863**	996	**1,802**	2,065
Operating expenses				
Operation, maintenance and administration	**620**	626	**1,212**	1,258
Depreciation and amortization	**193**	208	**378**	404
Property and capital taxes *(note 2)*	**28**	28	**59**	44
Restructuring costs *(note 6)*	-	-	**210**	-
Loss on transition rate option contracts *(note 3)*	**-**	-	**210**	-
Gain on sale of decontrol fixed assets *(note 10)*	**(99)**	-	**(99)**	-
	742	862	**1,970**	1,706
Operating income (loss)	**121**	134	**(168)**	359
Net interest expense	**39**	37	**78**	71
Income (loss) before income taxes	**82**	97	**(246)**	288
Income taxes (recoveries) *(note 2)*				
Current	**23**	238	**(45)**	272
Future	**(4)**	(158)	**(47)**	(103)
	19	80	**(92)**	169
Net income (loss)	**63**	17	**(154)**	119
Basic and fully diluted earnings (loss) per common share (dollars)	**0.25**	0.07	**(0.60)**	0.46
Common shares outstanding (millions)	**256.3**	256.3	**256.3**	256.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

(millions of dollars)

	Six Months Ended June 30	Restated *(note 5)*
	2002	**2001**
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 (loss)	**(154)**	119
Dividends	**(134)**	(100)
Retained earnings, end of period	**56**	586

See accompanying notes to the consolidated financial statements

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

	Three Months Ended June 30		Six Months Ended June 30	
		Restated *(note 5)*		Restated *(note 5)*
	2002	**2001**	**2002**	**2001**
Operating activities				
Net income (loss)	**63**	17	(154)	119
Adjust for non-cash items:				
Depreciation and amortization	**193**	208	378	404
Deferred pension asset	**(18)**	8	4	36
Other post employment benefits	**36**	23	52	57
Future income taxes	**(4)**	(158)	(47)	(103)
Provision for restructuring	**-**	-	210	-
Loss on transition rate option contracts	**(18)**	-	192	-
Gain on sale of investments	**-**	-	(7)	-
Gain on sale of decontrol fixed assets	**(99)**	-	(99)	-
Other	**36**	11	66	23
	189	109	595	536
Fixed asset removal and nuclear waste management fund	**(109)**	(95)	(160)	(217)
Expenditures on nuclear waste management	**(21)**	(13)	(52)	(23)
Expenditures on restructuring	**(64)**	-	(64)	-
Net changes to other long-term assets and liabilities	**(75)**	(3)	(67)	(40)
Deferred revenue	**(8)**	-	(14)	-
Non-cash working capital changes:				
Accounts receivable	**570**	13	588	132
Income tax recoverable	**10**	-	(77)	-
Fuel inventory	**(64)**	(39)	(48)	2
Materials and supplies	**(16)**	(56)	(19)	(59)
Accounts payable and accrued charges	**(451)**	202	(594)	(130)
Cash flow provided by (used in) operating activities	**(39)**	118	88	201
Investing activities				
Proceeds from Bruce decontrol *(note 10)*	**-**	370	-	370
Net proceeds from short-term investments	**-**	1	39	226
Proceeds on sale of decontrol fixed assets	**342**	-	342	10
Proceeds from sale of investments *(note 11)*	**-**	-	14	-
Expenditures for fixed assets	**(210)**	(154)	(366)	(269)
Cash flow provided by investing activities	**132**	217	29	337
Financing activities				
Repayment of long-term debt	**-**	-	-	(100)
Dividends paid	**-**	(14)	(134)	(100)
Short-term notes issued	**-**	-	200	-
Short-term notes repaid	**(200)**	-	(200)	(50)
Cash flow (used in) financing activities	**(200)**	(14)	(134)	(250)
Net increase (decrease) in cash and cash equivalents	**(107)**	321	(17)	288
Cash and cash equivalents, beginning of period	**90**	532	-	565
Cash and cash equivalents, end of period	**(17)**	853	(17)	853

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	**June 30 2002**	**December 31 2001**
Assets		
Current assets		
Short-term investments	**-**	39
Accounts receivable	**422**	1,010
Income taxes recoverable	**154**	77
Fuel inventory	**585**	537
Materials and supplies	**56**	35
	1,217	1,698
Fixed assets		
Property, plant and equipment	**14,519**	14,460
Less: accumulated depreciation	**1,743**	1,479
	12,776	12,981
Other assets		
Deferred pension asset	**302**	330
Fixed asset removal and nuclear waste management fund *(note 8)*	**1,368**	1,208
Long-term note receivable *(note 10)*	**225**	225
Materials and supplies	**189**	179
Long-term accounts receivable and other assets	**105**	65
	2,189	2,007
	16,182	16,686
Liabilities		
Current liabilities		
Bank indebtedness	**17**	-
Accounts payable and accrued charges *(note 3)*	**1,167**	1,505
Deferred revenue due within one year	**15**	13
Long-term debt due within one year *(note 7)*	**105**	205
	1,304	1,723
Long-term debt *(note 7)*	**3,115**	3,015
Other liabilities		
Fixed asset removal and nuclear waste management *(note 8)*	**4,817**	4,724
Other post employment benefits	**947**	924
Long-term accounts payable and accrued charges *(notes 3, 10)*	**384**	336
Deferred revenue	**201**	215
Future income tax liabilities *(note 2)*	**232**	279
	6,581	6,478
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**56**	344
	5,182	5,470
	16,182	16,686

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2002 (UNAUDITED)

1. Basis of Preparation

These interim consolidated financial statements do not contain all disclosures required by Canadian generally accepted accounting principles for annual financial statements, and 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.

2. 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. GRC costs are included in fuel expense.

3. 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 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.

During the second quarter of 2002, the provision was reduced by $18 million and the amount was included in revenue. At June 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 $82 million.

4. Other Accounting Policies Related to Open Market

Market Power Mitigation 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 most significant 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 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. No accrual was required at June 30, 2002 because the average price was less than 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 based on the timing of the underlying transactions and included in generation revenue. All contracts that are not designated as a hedge are valued at market value with changes in fair value recorded in energy marketing revenue as trading gains or losses.

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.

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.

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 six months ended June 30, 2001 have been restated to reflect an increase in employee benefit expenses of $51 million and a decrease in net income of $46 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

Restructuring charges are related to a reduction in the workforce of approximately 2,000 employees and include severance costs and related pension and OPEB expenses. During the first quarter of 2002, OPG approved voluntary severance packages for approximately 1,200 employees. Involuntary terminations will be required to meet the remaining workforce reductions over the next two to three years. The provision for restructuring costs recorded in the first quarter of 2002 was $210 million. This amount is in addition to a restructuring charge of $67 million recorded in the fourth quarter of 2001. During the second quarter of 2002, there were payments of $64 million related to restructuring.

7. Long-term Debt

The Company reach 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.

8. Fixed Asset Removal and Nuclear Waste Management Liabilities

Nuclear Funds Agreement

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. A Used Fuel Fund will be used to fund future costs of nuclear used fuel waste management. A 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 in the current year.

Since April 1, 1999, OPG has contributed $1,368 million including interest earned of $140 million to the nuclear fixed asset removal and nuclear waste management fund. The Decommissioning Fund will be funded through the 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 be responsible for the risk of liability and cost increases with respect to fixed asset removal and low and intermediate level waste. OPG will also continue to be responsible for the risk of liability and cost increases for used fuel waste management, subject, however, to limits in OPG’s financial exposure through the Agreement.

The Province will provide, under the Agreement, to the Canadian Nuclear Safety Commission ("CNSC"), as required by the *Nuclear Safety and Control Act* (Canada), 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 Fund, 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 accounts and from its annual contributions. 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, the accrued liabilities as at June 30, 2002 were reduced by $8 million.

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 treated as a hedge. 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. These derivatives are recognized in income over the term of the contract and are not recorded on the balance sheet. Fair values have been estimated by reference to quoted market prices for actual or similar instruments where available.

(*millions of dollars)*	**June 30, 2002**	**December 31, 2001**
	Fair Value	Fair Value
Carrying amount (fair value) of contracts not used for hedging purposes		
Commodity derivative instruments	**(7)**	-

At June 30, 2002, the fair value of commodity derivative instruments not used for hedging purposes includes a $9 million liability related to legacy contracts from the previous market structure, and transmission rights and other short-term contracts with a fair value of $2 million.

	June 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	**46 TWh**	**1-5 yrs**	**125**	14	1-5 yrs	-
Gas	**1,365,546 GJ**	**Aug/02**	**1**	-	-	-
Foreign exchange derivative instruments	**$385 US**	**Apr/03**	**(19)**	$147 US	Mar/02	3

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 L.P. ("Bruce Power"). 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 percent annually. The interest is recorded as non-energy revenue.

Under the terms of the lease, OPG transferred certain fuel and material inventory to Bruce Power, in addition to certain fixed assets. OPG will transfer pension assets and liabilities related to the approximately 3,000 employees who transferred from OPG to Bruce Power. Bruce Power has also assumed the liability for OPEB for these employees. OPG will pay Bruce Power in respect of OPEB benefits over a 72-month period. The impact to the deferred pension asset and the value of the OPEB obligation will be finalized through actuarial processes, which are expected to be completed in 2002.

As part of the lease agreement, OPG receives annual lease payments. The lease payments include monthly fixed payments and supplemental payments based on the number of operating units. The supplemental lease payment structure replaces a net revenue-sharing arrangement that was negotiated as part of the original lease agreement.

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 associated with the fossil-fuelled stations that have been identified for decontrol, namely Thunder Bay, Atikokan, Lennox and Lakeview generating stations. The amounts that OPG will ultimately realize with respect to these potential transactions could differ materially from the amounts recorded in the financial statements.

11. Other Initiatives

In February 2002, OPG sold its remaining ownership interest in Kinectrics Inc. to AEA Technology plc for approximately $12 million in cash proceeds.

In March 2002, OPG divested its 49% joint venture interest in New Horizon System Solutions ("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.

12. 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

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. Commencing May 1, 2002, physical sales to interconnected markets by OPG may be supplied using electricity purchased from the IMO-administered physical market, other independent system operators or other generators and are therefore considered energy marketing activities.

Energy Marketing

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
(millions of dollars)

3 months ended June 30, 2002	**Generation**	**Energy Marketing**	**Non-Energy & Other**	**Total**
Revenue	1,186	19	83	1,288
Fuel	332	-	-	332
Power purchased	75	18	-	93
Gross margin	779	1	83	863
Operation, maintenance and administration	604	2	14	620
Depreciation and amortization	156	-	37	193
Property and capital taxes	14	-	14	28
Gain on sale of fixed assets	-	-	(99)	(99)
Operating income (loss)	5	(1)	117	121
Net interest expense			39	39
Income before income taxes				82

3 months ended June 30, 2001	**Generation**	**Energy Marketing**	**Non-Energy & Other**	**Total**
Revenue	1,458	-	49	1,507
Fuel	338	-	-	338
Power purchased	173	-	-	173
Gross margin	947	-	49	996
Operation, maintenance and administration	613	-	13	626
Depreciation and amortization	164	-	44	208
Property and capital taxes	12	-	16	28
Operating income (loss)	158	-	(24)	134
Net interest expense			37	37
Income before income taxes				97

6 months ended June 30, 2002	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	2,656	19	170	2,845
Fuel	731	-	-	731
Power purchased	294	18	-	312
Gross margin	1,631	1	170	1,802
Operation, maintenance and administration	1,178	2	32	1,212
Depreciation and amortization	306	-	72	378
Property and capital taxes	30	-	29	59
Restructuring costs	-	-	210	210
Loss on transition rate option contracts	-	-	210	210
Gain on sale of fixed assets	-	-	(99)	(99)
Operating income (loss)	117	(1)	(284)	(168)
Net interest expense			78	78
Income (loss) before income taxes				(246)

6 months ended June 30, 2001	Generation	Energy Marketing	Non-Energy & Other	Total
Revenue	2,968	-	78	3,046
Fuel	706	-	-	706
Power purchased	275	-	-	275
Gross margin	1,987	-	78	2,065
Operation, maintenance and administration	1,239	-	19	1,258
Depreciation and amortization	346	-	58	404
Property and capital taxes	25	-	19	44
Operating income (loss)	377	-	(18)	359
Net interest expense			71	71
Income before income taxes				288

Selected Balance Sheet Information

June 30, 2002				
Segment property, plant & equipment	13,866	-	653	14,519
December 31, 2001				
Segment property, plant & equipment	13,895	-	565	14,460

Selected Cash Flow Information

3 months ended June 30, 2002				
Capital expenditures	150	-	60	210
3 months ended June 30, 2001				
Capital expenditures	133	-	21	154
6 months ended June 30, 2002				
Capital expenditures	264	-	102	366
6 months ended June 30, 2001				
Capital expenditures	222	-	47	269

13. 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.

14. Comparative Figures

Certain of the 2001 comparative figures have been reclassified and restated to conform to the 2002 financial statement presentation.

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