OTHER REVENUES – REGULATED HYDROELECTRIC

1.0 PURPOSE

This section explains the treatment in this Application of revenues other than energy production ("other revenues") from OPG's regulated hydroelectric generating facilities.

2.0 OVERVIEW

Some of OPG's regulated hydroelectric generating facilities are a source of other revenues. These include revenues associated with ancillary services, such as the provision of black start capability, operating reserve, reactive support/voltage control service, and automatic generation control ("AGC") as well as other sources not specifically defined under the category of ancillary services, including congestion management settlement credits ("CMSC"), segregated mode of operation ("SMO"), and water transactions. This section provides a description of these sources of other revenues, along with proposals for their treatment in both the interim period and the test period.

Other revenues associated with ancillary services were forecast for the interim period and the test period. The forecast revenues were included as an offset in the calculation of the revenue requirement for the regulated facilities. These ancillary services are integral to the operation of OPG's prescribed assets. Differences between forecast and actual revenues associated with these ancillary services, qualify for inclusion within the interim variance account, as per subsection 5 (1) (c) of O. Reg. 53/05. For information on existing and proposed variance accounts, see Exhibit J.

Forecast revenues from sources of other revenues that are not associated with ancillary services (CMSC, SMO, and water transactions) were not included in the calculation of the revenue requirement during the interim and test periods because revenues associated with these activities are difficult to forecast accurately. Further, these activities are not covered by the variance accounts, established pursuant to section 5 of O. Reg. 53/05. For these reasons, along with the high degree to which these activities are integrated with the operation of the electricity market and OPG's need for market-based incentives in respect of these activities, OPG has proposed different regulatory treatments for the revenues from these activities for both the interim and test periods. The proposed treatments for these categories of other revenues are set out below.

3.0 ANCILLARY SERVICES

There are three contract based ancillary services. The services of black start capability and AGC are purchased by the IESO through competitive tendering processes. The service of reactive support/voltage control is contracted by the IESO through a negotiated process and is not competitively tendered. Suppliers of these services receive compensation for costs associated with being available to provide this service, out-of-pocket costs, opportunity costs when providing the service, and any other compensation deemed by the IESO to be fair and reasonable. The cost of these services is passed on to consumers by the IESO through monthly uplift charges[1].

In contrast, operating reserve is a market based ancillary service that is jointly optimized with the energy market. Although operating reserve is not a contract based ancillary service, under Part 5 (a) of OPG's Generator Licence (EG-2003-0104), OPG is required to offer operating reserve at a price that does not exceed a bid cap. This bid cap is negotiated as part of an agreement between OPG and the IESO and provides for the recovery of costs similar to those described above.

3.1 Ancillary Service - Black Start Capability

Black start capability, as defined in the Market Rules, means the capability of a generation facility to start without an outside electrical supply so as to be used to energize a defined portion of the IESO-controlled grid. The IESO, in recognition of this being a critical service for purposes of system recovery, security and reliability, procures this capability from certain generation facilities that have the capacity to meet this need in the event that such a need arises.

[1] Monthly uplift charges are primarily comprised of the costs for black start, reactive support / voltage support, and AGC which are purchased under contract to maintain the reliability of the Ontario power network.

Sir Adam Beck II and R.H. Saunders are the two OPG facilities currently under contract with the IESO for black start capability.

In forecasting black start capability revenues for the interim period, OPG started with the contracts as they existed in June 2004 and then took into account anticipated changes in the subsequent contract term, which commenced on November 1, 2005 and expired on April 30, 2007. That contract was renewed under the same terms and conditions for an additional 18 month period, effective May 1, 2007 and provided for a five percent increase in revenues for the new term. In forecasting black start capability revenues for the test period, OPG assumed the existing contract would be extended for another 18 month term with similar terms and conditions. This would also apply to the period from November 1, 2008 to May 1, 2010.

3.2 Ancillary Service - Reactive Support/Voltage Control Service

Under the Market Rules, reactive support service means a service provided by a market participant so as to allow the IESO to maintain the reactive power levels required by the IESO-controlled grid. Similarly, voltage control service means a service provided by a market participant so as to allow the IESO to maintain voltage levels required by the IESO-controlled grid. Collectively, these are referred to in this Application as reactive support/voltage control service.

In forecasting revenues for the interim period, OPG based its forecast on the actual revenues achieved for a historical period which was representative of operations for 2005. A three percent escalation factor representing inflation was included for 2006.

OPG and the IESO negotiated a Reactive Support/Voltage Control Service Agreement effective from July 1, 2006 until December 31, 2007. In forecasting revenues for 2007, 2008 and 2009, updated information from the existing contract and a three percent escalation factor representing inflation per year was applied.

The nuclear assets also receive revenues associated with the provision of reactive support/voltage control service. These revenues are presented in Ex. G2-T1-S1.

3.3 Ancillary Service - Automatic Generation Control

As defined in the Market Rules, AGC means the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between load and the output from generation facilities.

For AGC, OPG's 2005 forecast was based on the average of actual station AGC revenues from April 2004 to June 2004. This period was selected as it represented the going-forward revenues anticipated in the contract executed in January 2004. Forecast contract revenues were increased in 2006 by three percent for inflation. The 2006 actual revenues were based on the AGC agreement between OPG and the IESO that was effective from November 1, 2005 to April 30, 2007.

Forecasts for 2008 and 2009 were based on the 2007 forecast plus an allowance for inflation of 3 percent. A new contract for AGC was executed with the IESO and became effective May 1, 2007 with an expiration date of April 30, 2009.

3.4 Ancillary Service - Operating Reserve

Operating reserve refers to the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingency. As such, operating reserve can either be generating capacity, or demand that can be reduced on short notice, by the IESO.

The IESO establishes separate prices for the energy market and the operating reserve markets. The IESO jointly optimizes these two markets to produce dispatch instructions and prices intended to result in the most cost-effective overall solution for the market. OPG is required to offer operating reserve from all available units under Part 5 (a) of its Generator Licence (EG-2003-0104). Operating reserve revenue consists of general operating reserve ("general OR") and congestion management settlement credits operating reserve ("CMSC

OR"). Because it is a market-based ancillary service, the amount of general OR accepted depends on OPG's operating reserve offers and market conditions. The amount of CMSC OR depends on the difference between the IESO market schedule and the IESO dispatch schedule. Further discussion of CMSC is provided in section 6.0, below.

For 2005 and 2006, the OR revenue forecasts were based on actual revenues with an adjustment for forecast production. Congestion management settlement credits operating reserve payments are not predictable and therefore revenues were left unadjusted. For 2007, 2008 and 2009, the OR revenue forecasts are based on 2006 actual revenues with an adjustment for forecast production and an allowance for inflation of three percent per year.

4.0 SEGREGATED MODE OF OPERATION

Segregated mode of operation is defined by the Market Rules as an electrical configuration where a portion of the IESO-controlled grid is used to connect one or more registered generating facilities to a neighbouring control area using a radial intertie for the purposes of delivering electricity or physical services to such neighbouring control area. The generating facilities will thus be isolated into the neighbouring control area when in segregated mode.

Segregated mode of operation transactions are accommodated by segregating up to eight units (or two banks of four units) of production from R.H. Saunders to Hydro-Québec's control area at St. Lawrence Transformer Station. When this occurs, these Saunders units are no longer connected to the Ontario IESO-controlled grid (although, they are recallable by the IESO for Ontario system need) and do not participate in the Ontario market. Rather, these units are now connected to the Hydro-Québec system and receive revenues from markets outside Ontario.

Segregated mode of operation allows OPG to facilitate market activity on its own behalf or on behalf of other market participants within the framework of the Market Rules. Prior to entering into a SMO configuration, OPG must seek approval from the IESO which can be refused or revoked and terminated at any time.

Segregated mode of operation is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties and are typically conducted in off-peak periods. The economic drivers used in deciding whether or not to engage in an SMO transaction are the forecast market prices in Ontario and surrounding markets.

Segregated mode of operation can provide several benefits to Ontario, such as:

(1) Providing a means for managing excess baseload generation (i.e., preventing the risk of poisoning out a nuclear unit or shutting down and restarting (two-shifting) a fossil unit which could lead to reliability issues or the spilling of water).
(2) Facilitating an improved environmental state through the minimization of spill from hydroelectric resources.
(3) Providing a potential economic benefit to ratepayers in Ontario by reducing market prices during on-peak periods as a result of possible re-injection of SMO energy into Ontario. Segregated mode of operation allows OPG to sell energy to external companies who may have the ability to fill water reservoirs (typically off-peak) and resell the energy into Ontario during a subsequent on-peak period when it is economic for them to do so. Imports result in a decrease in hourly Ontario energy price ("HOEP") as these transactions generally occur when Ontario demand is high, supply is more constrained and more expensive generation is on line.

Within the IESO-administered market, exports are treated as a load. All export activity, including SMO, has the potential to increase HOEP as these activities increase market demand. As OPG's SMO activity typically occurs during off-peak periods, when market demand is lower and low cost supply is readily available, there may only be a small change in price to replace this energy with the next available generator in the dispatch stack. Therefore the impact on HOEP is expected to be minimal. Further, a recent study released by the IESO dealing with behavioural responses to market events indicates that export volumes tend to decrease following an increase in HOEP[2]. Therefore, based on this price/volume relationship, SMO exports would likely be counter-balanced by a reduction in other exports and leave HOEP at about the same level with or without SMO.

Ontario Regulation 53/05 does not address the treatment of incremental revenue from SMO transactions. However, OPG believes that the treatment of this incremental revenue should be consistent with the intent of the incentive mechanism under the Regulation. Specifically subsection 4 (2) of O. Reg. 53/05 includes a market-based incentive mechanism that encourages OPG to maximize its production at OPG's regulated hydroelectric generating facilities during peak periods or during times of highest market prices. Electricity output from the regulated hydroelectric generating facilities in excess of 1900 MW in any hour receives HOEP.

The regulated payment amounts have been calculated using an energy production forecast that includes all of R.H. Saunders' forecast energy production (whether injected into the Ontario market or into Québec). For purposes of the regulated payment amount calculation, SMO revenues are not used as an offset to the hydroelectric revenue requirement. The volume and revenue associated with SMO transactions are difficult to forecast as they are a response to hourly market-based signals (specifically demand and excess generation) and prices.

As described in the paragraphs that follow, OPG will share the net revenues it earned from SMO transactions for the interim period. In the descriptions below (and in the next section on Water Transactions), 1900 MWh in any hour refers to the threshold value for the hydroelectric incentive mechanism during the interim period.

For those hours when production into the Ontario market from the regulated hydroelectric generating facilities is at or below 1900 MWh for any hour, OPG will receive $33/MWh for the

[2] Presentation to the IESO Market Pricing Working Group, May 9, 2007, "Behavioural Response to Market Events".

production injected into the Ontario market and for any portion of the SMO volume below 1900 MWh. For this same SMO volume, the ratepayer receives either the net revenue between HOEP and $33/MWh if market prices are greater than the regulated rate or absorbs the difference if market prices are lower than the regulated rate. This treatment ensures that OPG receives the rate of $33/MWh for generation up to 1900 MWh which as described above was calculated by including all of R.H. Saunders' production. OPG will share with ratepayers on a 50/50 basis the net revenues[3] from the greater of the regulated rate or HOEP to the transaction sale price for the SMO volume at or below 1900 MWh. This treatment preserves an incentive to engage in SMO transactions while sharing with ratepayers revenues in excess of HOEP up to the transaction sale price.

For those hours when production into the Ontario market from the regulated hydroelectric generating facilities is above 1900 MWh for any hour OPG will retain all SMO revenues. This treatment is consistent with the incentive mechanism set out at section 5 of O. Reg. 53/05 which provides that OPG is to receive market prices for this production.

Segregated mode of operation net revenues include incremental costs which consist of transmission export fees, transmission charges in other control areas and transmission losses between generator source and point of delivery. Segregated mode of operation transactions are also exposed to market price forecasting risk. These transactions are usually executed ahead of time and may be indexed to market price. If the actual price is greater than the forecast price used at the time of the decision to transact, margins associated with the transaction will be lower.

The net revenues from SMO transactions are acquired through OPG's non-regulated business which moves generation to higher priced markets. The non-regulated business incurs additional costs including; arranging, conducting and settling these transactions; IT systems; control and governance functions; and market memberships.

[3] SMO net revenues are defined as gross revenues less HOEP (or HOEP proxy costs), incremental variable costs, and costs associated with the non-regulated business. If the transaction is not indexed to HOEP but is executed at a fixed price, the HOEP for that hour is used as a proxy.

For the period April 1, 2005 to December 31, 2005, SMO net revenues were approximately $9.9M based on an average transaction premium[4] of approximately $14.26/MWh. For the calendar year 2006, SMO net revenues were approximately $5.4M based on an average transaction premium of approximately $10.14/MWh. Similarly for the calendar year 2007, SMO net revenues were approximately $4.4M based on an average transaction premium of approximately $9.28/MWh.

OPG also incurs additional costs and risks which have not been included in the figures above. By engaging in these transactions, OPG incurs a loss of production during switching operations and may experience other risks such as the IESO preventing or recalling the units as per the Market Rules; equipment failure (i.e., a breaker or switch failure) which may prevent the units from being connected back to Ontario until the equipment is repaired; or a unit being forced out. If the units are unable to segregate for the reasons identified above, OPG may be financially responsible for not delivering on its commitment to a transaction in another market.

OPG also requires a risk premium to recover exposure to risks such as counterparty credit and liquidated damages; and a reasonable rate of return in order to consider a commercial transaction.

For the test period, OPG is proposing a modified treatment, for incremental net revenues from SMO transactions, given the proposed change in the hydroelectric incentive mechanism (described in Ex. I1-T1-S1). The treatment of incremental revenues from SMO transactions needs to be integrated with this proposed hydroelectric incentive mechanism and take into consideration those changes suggested to the new mechanism. The main difference for SMO transactions is to the fixed threshold volume of 1900 MWh which will be replaced by an hourly volume that is equal to the actual hourly average net energy production[5] over a month (described in Ex. I1-T1-S1).

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[4] The average transaction premium is defined as the sale price less HOEP.

[5] Net energy production is defined as all production from the hydroelectric regulated assets including SMO production less load (including pump load from Sir Adam Beck Pump Generating Station).

Future SMO transaction volumes are anticipated to decrease as a new 1,250 MW direct current interconnection between Ontario and Québec comes into service. Phase 1 of the project has an in-service date of May 2009 and a capability of 900 MW. Phase 2 will be in-service in the spring of 2010 increasing the capability to 1,250 MW. This intertie will allow transactions directly and will therefore reduce SMO transactions.

5.0 WATER TRANSACTIONS

Water transactions between the New York Power Authority ("NYPA") and OPG are associated with the regulated hydroelectric facilities. NYPA and OPG are designated in their respective jurisdictions as the entities responsible for developing and operating the hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to agreements between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total water available for generation under the relevant international treaties. Water transactions are one means by which NYPA and OPG maximize energy production. Water transactions provide the opportunity to maximize use of the available water by permitting, under certain circumstances, an entity to extract at such entity's generating facility(ies) (the "Generating Entity") the potential energy from a portion of the other entity's share of the water available for power generation under the relevant international treaties. In return, the Generating Entity provides the revenues resulting from the water transactions, minus an accommodation charge, to the other entity. Historically, these water transactions were settled through physical transfers of energy between NYPA and OPG. However, since the opening of electricity markets in the respective jurisdictions, water transactions are now settled financially.

Water transactions generally occur for one of three reasons:

- Maintenance: Either NYPA or OPG can have outages that prohibit the full utilization of Canada's or the United States' share of water available for generation pursuant to the

- relevant Treaties.
- Economic Transactions: Transactions are conducted due to efficiency advantages associated with one entity's generation units over the other, or due to expected spill conditions.
- Ice: At times during the winter, the formation or flushing of ice at Niagara prevents either OPG or NYPA from utilizing Canada's or the United States' share of water available for generation pursuant to the relevant treaties. Under these circumstances the parties have agreed to share the losses associated with these water transactions.

Due to difficulties in forecasting both the water transaction volumes and their associated revenues, water transaction revenues are assumed to be zero and are not used as an offset to the regulated facilities' revenue requirement. However for the purposes of interim payments to the Ministry of Finance, gross revenue charges associated with these water transactions are forecast as described in Ex. F1-T4-S1.

For the interim period, OPG will share water transaction net revenues[6] consistent with the interim period treatment previously described for SMO and as further described below.

For those hours when production into the Ontario market from the regulated hydroelectric generating facilities is at or below 1900 MWh for any hour, and OPG engages in a water transaction which allows NYPA to extract the potential energy from Canada's share of available water, OPG will receive $33/MWh for the production injected into the Ontario market and any portion of the water transaction volume at or below 1900 MWh. For this same water transaction volume that is at or below 1900 MWh, the ratepayer receives either the net revenue between HOEP and $33/MWh if market prices are greater than the regulated rate or absorbs the difference if market prices are lower than the regulated rate. This treatment ensures that OPG receives the rate of $33/MWh for production up to 1900 MWh in any hour including any allocation of water transaction energy. OPG and the ratepayer will share on a 50/50 basis the net revenues from the greater of the regulated rate or HOEP to

[6] Water Transaction net revenues are gross revenues less accommodation charges, and GRC.

the transaction sale price for the water transaction volume at or below 1900 MWh. This treatment preserves a market incentive to engage in water transactions while sharing with ratepayers revenues in excess of HOEP up to the transaction sale price.

For those hours when the output from OPG's regulated hydroelectric facilities is greater than 1900 MWh in any hour and additionally, OPG engages in a water transaction whereby it allows NYPA to extract the potential energy from Canada's share of available water, OPG will retain all water transaction revenues received from NYPA. This treatment is consistent with the incentive mechanism set out in section 4 (2) in O. Reg. 53/05.

When NYPA engages in a water transaction whereby it allows OPG to extract the potential energy from the United States' share of available water, OPG inherits a financial obligation equivalent to the energy production priced at HOEP. When the output from OPG's regulated hydroelectric facilities is less than 1900 MWh and there is a water transaction from NYPA to OPG, there is an energy credit to NYPA at HOEP. Any difference between HOEP and $33/MWh for the water transaction amount will be allocated as a cost in supplying this product. This treatment ensures that OPG receives the rate of $33/MWh for generation up to 1900 MWh. When the output from OPG's regulated hydroelectric facilities is greater than 1900 MWh, OPG will retain the entire obligation to pay NYPA at HOEP less accommodation charges associated with the transaction. Water transactions from NYPA to OPG have been relatively small with approximately $0.002M in gross revenues in 2005 and $0.2M in gross revenues in 2006. Once costs are included, the net revenues are not material enough to be addressed.

The majority of water transactions are for the purposes of salvaging the water that forms part of an entity's generation share that would otherwise be spilled over Niagara Falls due to the inability to use it or are used to facilitate ice procedures. Water transactions are required to ensure that the waters available for power generation under the relevant treaties are utilized in the most efficient manner, thereby maximizing all power potential from the resource.

For the period April 1, 2005 to December 31, 2005, water transaction incremental net revenue was $11.6M, for the 2006 calendar year was $12.5M and for the 2007 calendar year was $5.9M. Gross revenue charges costs associated with these transactions were $5.2M in 2005 (for the entire year), $4.1M in 2006 and $1.4M in 2007 (see Ex. F1-T4-S1). Water transaction net revenues were $7.8M during April 1 to December 31, 2005, $8.4M for 2006 and $4.5M for 2007.

For the test period, OPG is proposing a similar approach to the one used in the interim period, modified consistent with the treatment previously described for SMO.

It is expected that water transactions will decrease significantly when the Niagara tunnel is in-service since increased diversion capability will then be available to the Niagara stations.

6.0 CONGESTION MANAGEMENT SETTLEMENT CREDITS

All dispatchable generating facilities in Ontario are dispatched under the Market Rules by the IESO's dispatch scheduling optimizer ("DSO"). The DSO is an algorithm that is used by the IESO to determine prices and schedules for dispatch. Prices are first determined by an unconstrained run of the DSO, which does not take transmission or other constraints into consideration. This results in an unconstrained schedule. Dispatch, including OPG's prescribed generating facilities, is next determined by a constrained run of the DSO, which does consider constraints, and results in the schedule actually used to dispatch the generation. Any difference between the unconstrained schedule and the constrained or dispatch schedule can give rise to a CMSC payment, which is intended to compensate a market participant for either being constrained on (operating when not economically justified) or constrained off (not operating when economically justified).

The DSO will jointly optimize energy and the three types of operating reserve (ten minute spinning, ten minute non-spinning and thirty minute). Congestion management settlement credits payments are available for energy and for each of the three types of OR in each five minute interval of dispatch.

Congestion management settlement credits payments ensure that a market participant who has been constrained on or constrained off by system conditions beyond its control is made whole up to the operating profit they would have received under an unconstrained schedule. This is to ensure that no market participant is put at an advantage or disadvantage by virtue of their geographic position relative to the grid. The unconstrained schedule is used to set the market clearing price and constrained on units do not benefit from their higher offers. The amount of the CMSC payment is primarily based on operating profit which is calculated as the difference between the unconstrained and the constrained quantity as well as the difference between the offer price and the market clearing price.

The majority of the CMSC payments associated with OPG's prescribed assets are for energy, with OPG's regulated facilities attracting some CMSC OR.

Although transmission limitations are the major cause for differences between the unconstrained and constrained schedules, there are other factors that give rise to such differences. These include unit operating minimums, unit ramp rates and the use of actual metered output for the unit. The IESO does not provide the means for market participants to identify all of the reasons for a constrained on or constrained off event.

Congestion management settlement credits are subject to review by the Market Assessment and Compliance Department of the IESO. These reviews can result in recovery of CMSCs by the IESO if the CMSC was associated with a local transmission restriction and there was insufficient competition available to satisfy the restriction.

CMSC situations typically result in inefficient operation and/or the incurring of additional costs by generators, driven by market conditions. For example, constrained off situations can result in wasted or inefficient use of water as the generator is operated below its maximum efficiency point. Similarly, constrained on situations typically require inefficient use of the hydroelectric generating units above the point of maximum efficiency. In addition, in a constrained off situation, lost production will not be recoverable through the water variance account and if the CMSC value is less than the regulated rate, OPG will not recover its costs.

CMSC payments for regulated assets were $12.6M for 2005, $8.5M for 2006 and $7.7M for 2007. OPG will retain all CMSC payments from prescribed generating facilities as constrained operation typically gives rise to inefficient operation and increased costs. The CMSC payment is not incremental revenue but is an offset to lost production/revenue and increased costs that are generally not included in the revenue requirement. The CMSC payment during constrained events is reasonable compensation for such inefficiencies and costs. Moreover, CMSC OR is separately addressed by the variance account associated with the operating reserve ancillary service.

7.0 OTHER REVENUES – 2006 ACTUAL TO 2009 PLAN

Exhibit G1-T1-S1 Table 1 presents the revenues associated with the regulated hydroelectric assets.

Nuclear ancillary service revenues are presented in Exhibit G2.

Numbers may not add due to rounding.

Table 1

Other Revenues - Regulated Hydroelectric ($M)

Line No.	Revenue Source	2005 Budget[5]	2005 Actual[5]	2006 Budget	2006 Actual	2007 Budget	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Ancillary Services[1,2]**	28.9	24.0	39.6	44.1	31.6	35.6	32.4	33.1
2	**Segregated Mode of Operation[3]**	0.0	9.9	0.0	5.4	0.0	4.4	0.0	0.0
3	**Water Transactions[4]**	0.0	7.8	0.0	8.4	0.0	4.5	0.0	0.0
4	**Total**	28.9	41.7	39.6	57.9	31.6	44.5	32.4	33.1

1 2005 ancillary services revenues are estimated for the Regulated Hydroelectric assets.
2 The 2005 and 2006 ancillary actuals are the reported numbers in OPG's financial statements based on estimates at year end. This number varies slightly from final IESO statements due to adjustments made after year end.
3 Segregated Mode of Operation net revenues are gross revenues less HOEP, incremental variable costs and costs associated with the non-regulated business.
4 Water Transaction net revenues are gross revenues less accommodation charges and GRC. GRC costs for April 1, 2005 to Dec 31, 2005 were prorated based on 9/12[ths] of the year.
5 2005 numbers are from April 1, 2005 to Dec 31, 2005.

COMPARISON OF REGULATED HYDROELECTRIC OTHER REVENUES

1.0 PURPOSE

This evidence presents period-over-period comparisons of other revenues for the regulated hydroelectric facilities.

2.0 OVERVIEW

Exhibit G1-T1-S2 Table 1 applies to all three sections below.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2009 Plan versus 2008 Plan

The difference between the operating reserve ("OR"), reactive support/voltage control, and automatic generation control ("AGC") revenue projections for 2009 and those for 2008 is due an allowance for inflation, which is estimated at three percent. The difference for the black start capability projections is due to an expected revenue increase of five percent as per the terms of the contract for subsequent periods.

2008 Plan versus 2007 Actual

The difference between revenue projections for 2008 and revenues for 2007 is the same as described above.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2007 Actual versus 2007 Budget

The actual 2007 ancillary service revenue for the regulated hydroelectric assets is approximately $4M higher than 2007 budget. This is due mainly to higher than forecast amounts of AGC requested by the IESO at Sir Adam Beck II than forecasted.

2007 Actual versus 2006 Actual

After the existing AGC contract was signed in May 2006, the IESO reduced the amount of AGC it requested from 150 MW to 100 MW. This change is responsible for the difference in other revenues between the 2006 actual and 2007 actual, with the reduction equaling approximately $700 K per month. OPG expects this quantity to be further reduced as the IESO has indicated that it expects to take less than 100 MW of AGC from OPG in the future.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2006 Actual versus 2006 Budget

The actual 2006 ancillary service revenue for the regulated hydroelectric assets is approximately $4.5M more than 2006 budget. This is due mainly to the AGC contract that was signed with the IESO for the period of November 2005 - May 2007 which resulted in increased revenue for 2006.

2005 Actual versus 2005 Budget

The actual 2005 ancillary service revenues for the regulated hydroelectric assets is approximately $4.9M less than the 2005 budget. This is due to the timing of the execution of the new contract and a retroactive payment for the latter part of 2005 being made in 2006.

Numbers may not add due to rounding.

Table 1

Comparison of Other Revenues - Regulated Hydroelectric ($M)

Line No.	Revenue Source	2005 Budget[5]	(c)-(a) Change	2005 Actual[5]	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Ancillary Services[1,2]**	28.9	(4.9)	24.0	20.1	44.1	4.5	39.6	(8.5)	35.6
2	**Segregated Mode of Operation[3]**	0.0	9.9	9.9	(4.5)	5.4	5.4	0.0	(1.0)	4.4
3	**Water Transactions[4]**	0.0	7.8	7.8	0.6	8.4	8.4	0.0	(3.9)	4.5
4	**Total**	28.9	12.8	41.7	16.2	57.9	18.3	39.6	(13.4)	44.5

Line No.	Revenue Source	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
5	**Ancillary Services[1,2]**	31.6	4.0	35.6	(3.2)	32.4	0.7	33.1
6	**Segregated Mode of Operation[3]**	0.0	4.4	4.4	(4.4)	0.0	0.0	0.0
7	**Water Transactions[4]**	0.0	4.5	4.5	(4.5)	0.0	0.0	0.0
8	**Total**	31.6	12.9	44.5	(12.1)	32.4	0.7	33.1

1 2005 ancillary services revenues are estimated for the Regulated Hydroelectric assets.
2 The 2005 and 2006 ancillary actuals are the reported numbers in OPG's financial statements based on estimates at year end. This number varies slightly from final IESO statements due to adjustments made after year end.
3 Segregated Mode of Operation net revenues are gross revenues less HOEP, incremental variable costs and costs associated with the non-regulated business.
4 Water Transaction net revenues are gross revenues less accommodation charges and GRC. GRC costs for April 1, 2005 to Dec 31, 2005 were prorated based on 9/12ths of the year.
5 2005 numbers are from April 1, 2005 to Dec 31, 2005.

ADJUSTMENT TO SMO SHARING METHODOLOGY

1. PURPOSE

The purpose of this evidence is to describe a minor adjustment to the treatment of revenues associated with Segregated Mode of Operation as described in Ex. G1-S1-T1.

2. ADJUSTMENT

During preparation for the hearing it was determined that, in certain circumstances, the sharing mechanism yielded results that were not appropriate. For this reason, a minor adjustment is proposed that affects both the interim period treatment as well as the proposed treatment for the test period. The adjustment results in a $3.3M increase in the amount returned to consumers through the Segregated Mode of Operation variance account, as described in Exhibit J.

In Ex. G1-T1-S1, page 8, lines 7-8, the following adjustment is made:

> "OPG will share with ratepayers on a 50/50 basis the net revenues from ~~the greater of the regulated rate or~~ HOEP to the transaction sale price for the SMO volume at or below 1900 MWh."

As a result of the above adjustment, the SMO variance account balance (Ex. J1-T1-S1, Table 3, line 19) will change as follows:

	2005	2006	2007	Total
Current Evidence	(9.5)	0.5	0.8	(8.2)
Adjusted Value	(9.9)	(0.7)	(0.9)	(11.5)

NON-ENERGY REVENUES - NUCLEAR

1.0 PURPOSE

The purpose of this section of evidence is to discuss OPG nuclear operations that generate non-energy revenue and explain OPG's proposed regulatory treatment for the test period.

2.0 NUCLEAR NON-ENERGY REVENUES

In the test period, in addition to Bruce Lease revenues and costs (including Bruce waste management revenues) which are discussed at Ex. G2-T2-S1, and OPG nuclear ancillary service revenues which are discussed at Ex. G2-T1-S1, OPG nuclear operations expects to earn revenues from the following non-energy related businesses:

- Heavy water sales and services – nuclear markets.
- Heavy water sales and services – non-nuclear markets.
- Isotope sales (cobalt 60; tritium).
- Inspection and Maintenance Services ("IMS").

These revenues (less operating costs) are applied as an offset to the nuclear revenue requirement.

2.1 Heavy Water

2.1.1 Heavy Water Inventory

Heavy water is a manufactured product required for CANDU (Canadian Deuterium Uranium) reactor operations. As discussed in Ex. F2-T2-S1, heavy water is required as a moderator for sustaining a nuclear reaction and as a heat transport in a CANDU nuclear reactor. OPG has a heavy water maintenance program designed to manage its inventory of heavy water, whether in storage or in use within its reactors. In addition, OPG has opportunities to sell heavy water and processing services to third parties as discussed below.

Chart 1

Heavy Water Inventory (Tonnes)

	RADIOACTIVE	NON-RADIOACTIVE	TOTAL
IN-SERVICE OPG	6,300		6,300
IN-SERVICE BRUCE	6,000		6,000
OTHER	1,140	1,000	2,140
TOTAL INVENTORY	**13,440**	**1,000**	**14,440**

OPG owns 14,440 tonnes of heavy water, of which 13,440 tonnes is radioactive, and 1,000 tonnes is non-radioactive heavy water. Of the 13,440 tonnes of radioactive heavy water, 12,300 tonnes are in-service located within OPG's operating CANDU nuclear units (6,300 tonnes) and within the reactors at the leased Bruce site (6,000 tonnes). The remaining 1,140 tonnes of radioactive heavy water are in out of service Units 2 and 3 at Pickering A, pending a move to a long-term storage facility, on loan/lease to other nuclear facilities (Atomic Energy of Canada, New Brunswick Power), and in OPG-owned storage facilities (about 40 tonnes). Non-radioactive heavy water is stored in two OPG-owned storage facilities, one on the Bruce Power site and managed by Atomic Energy of Canada Limited under contract to OPG, and the other at Darlington.

As discussed at Ex. F2-T2-S1, OPG earmarks part of its radioactive inventory (slightly over 500 tonnes) to replenish at a rate of three tonnes per year per reactor the heavy water at the existing OPG and Bruce Power facilities (the Bruce Lease Agreement requires OPG to provide this support, as well as detritiation services). The balance of the heavy water inventory, i.e., both the radioactive and non-radioactive heavy water either not in-service or earmarked for replenishment, amounts to 1,640 tonnes (i.e., 2140 tonnes less 500 tonnes). This quantity is available to meet future OPG/Bruce Power needs arising out of plant life extensions, restart (at Bruce Power), new build decisions, and for sale, loan or lease to qualified third parties, subject to regulatory constraints. There is no current commercial production of heavy water in North America. International suppliers include Argentina, Romania, and India.

2.1.2 <u>Sales of Heavy Water and Services</u>

The heavy water sales and service business includes both the sale of heavy water to nuclear and industrial/medical clients, as well as the provision of tritium removal (detritiation) services by processing through the Darlington Tritium Removal Facility ("TRF").

OPG is a world leader in heavy water sales and services. Total heavy water sales/leases and services to third parties amounted to $18.9M in 2006 and $30.3M in 2007 and are forecast to reach $27.0M in 2008. Revenues for 2007 consisted of $19.5M to nuclear markets and $10.8M to non-nuclear markets (e.g., non-radioactive heavy water sales). Sales to nuclear markets include a one-time heavy water sale to a nuclear energy company based in China.

OPG provides additional quantities of heavy water to Bruce Power as well as detriation services. The Bruce Lease Agreement includes an obligation for OPG to provide 18 tonnes per year of heavy water to Bruce Power for loss make-up over the term of the lease. The potential for sales beyond that amount is limited. The restart of the Bruce A units may provide an opportunity for additional heavy water sales in the future.

OPG sells detritiation services to Bruce Power. Indeed, the bulk of the heavy water sales and service revenues from the nuclear markets are from the provision of detritiation services to Bruce Power. Opportunities for providing detritiation services to other third parties is limited, because of market demand and because there are storage and capacity restrictions at the TRF processing facility.

The market for heavy water sales to nuclear facilities remains very small. Sales are primarily for loss make-up, and very occasionally for inventory build-up or topping-up. The non-nuclear markets include research institutions, pharmaceutical companies, laser manufacturers, and chemical companies. The market is relatively stable and limited ($8M to $10M/year). In some instances, OPG takes back depleted or degraded (but non-radioactive) heavy water. After cleaning and upgrading (a process which makes it radioactive and only suitable for reactor use), this water is returned to OPG inventory. All sales, loans or leases are subject to Canadian Nuclear Safety Commission ("CNSC") regulatory approval, as heavy water is a controlled nuclear substance, as defined in the regulations to the *Nuclear Safety and Control Act*.

OPG has also agreed to receive about 280 tonnes of radioactive heavy water from the Japan Atomic Energy Authority from a decommissioned Japan Atomic Energy Authority research reactor over the period 2004 - 2010. This heavy water is processed as capability permits (OPG is paid by Japan Atomic Energy Authority to process, clean-up and assume title of their excess radioactive heavy water), and is then added to OPG inventory. Adding to the inventory of radioactive heavy water provides an opportunity for future sales of non-radioactive heavy water should opportunities emerge, without jeopardizing reserves required to serve life extension needs or new build. Some of the tritium that is removed during the detritiation process is sold for industrial use (see isotopes sales below)**.**

Total revenues for heavy water sales and services are summarized in Ex. G2-T1-S1 Table 1. Cost of goods sold and related indirect costs are described in section 3 below.

2.2 Isotope Sales

2.2.1 Cobalt-60

Cobalt-60 produced by OPG is used mainly in the health industry for diagnostic and therapeutic purposes treatment and to sterilize surgical and medical supplies. A second, potentially large market developing in North America is the food Industry (i.e., food irradiation).

All cobalt-60 sales are subject to CNSC regulatory approval, as colbalt-60 is a controlled nuclear substance.

Cobalt-60 is produced at Pickering B (Units 6, 7, and 8) by inserting adjuster rods containing cobalt-59 in the reactor core (rods are used to adjust power levels). Over time the cobalt-59 absorbs a neutron and becomes cobalt-60. About every 24 months, in line with a planned outage, the adjuster rods containing cobalt-60 are removed, replaced, cut up, and safely stored before shipping to a licensed end-user. OPG sells the cobalt-60 under an exclusive long-term agreement to a third party.

Total revenues from cobalt-60 sales over the period 2006 - 2009 are shown in Ex. G2-T1-S1 Table 1. Yearly revenue variations are generally driven by timing of the cobalt harvest (tied to outage schedule of the Pickering units). The potential for revenue growth is limited, as sale volumes are constrained by the ability to produce cobalt-60. The cost of goods sold for this activity is discussed in section 3.0 below.

2.2.2 Tritium Sales

Tritium is a by-product of electricity generation using CANDU technology. It is produced by irradiation of heavy water. Concentration limits of tritium in reactor heavy water inventories have been established by the CNSC for each nuclear station. In order to remain within these limits, tritium is removed from the heavy water via the TRF (see Ex. F2-T2-S1).

All tritium sales are subject to CNSC regulatory approval, as tritium is a controlled nuclear substance.

OPG has entered into short-term contracts to sell the tritium to government-approved organizations for authorized commercial and health industry uses. Commercial use of tritium includes luminescent signs for use in areas with no power source (e.g., airport runway lights, emergency exit signs) and as a tracer for diagnostic pharmaceuticals and medical research.

While tritium sales have been relatively small and stable over time, OPG is increasingly facing price competition from international suppliers, primarily Russia. The increase in the value of Canadian dollar (relative to the U.S. dollar) has also affected OPG’s competitiveness in this market. The joint International Fusion Research project in France may present an opportunity for future tritium sales. The revenue forecast includes some minor tritium sales to International Fusion Research, related to preparatory research work.

Total revenue from tritium sales over the period 2006 - 2009 is shown in Ex. G2-T1-S1 Table 1. The cost of goods sold and related indirect costs are described in section 3 below.

2.3 Inspection and Maintenance Services

OPG's IMS group is a leading provider of inspection, maintenance and technical services to nuclear and non-nuclear power generation facilities. Through its inspection services, IMS provides detection, characterization and sizing of material flaws in a variety of components and equipment. Through its maintenance services, IMS provides boiler tube plugging and removal, reactor fuel channel spacer relocation, fuel channel replacement and reconfiguration and feeder grayloc maintenance. Inspection and Maintenance Services also offers a project management service for development of new inspection and maintenance equipment. The core activities of IMS are:

- Fuel channel and reactor vault inspection and maintenance.
- Steam generator and heat exchangers inspection and maintenance.
- Balance of plant inspections.
- Development of inspection and maintenance tooling.

Inspection and Maintenance Services is geographically dispersed throughout southern Ontario with regular staff resident at the Bruce Power, Darlington, and Pickering sites, as well as several off-site locations in Pickering and Ajax. To maximize the utilization of staff, IMS deploys staff to all sites during the spring and fall outage seasons. A substantial level of staff augmentation is required to address the seasonal outage work programs. Inspection and Maintenance Services nearly doubles in size using augmented staff (i.e., temporary additions to staff complements for peak periods) during outage campaigns from 534 regular staff to approximately 900 staff during outages to facilitate execution of the work program.

A key 2008 initiative is to increase regular (full time) staffing levels and reduce the reliance on augmented staff. Optimal regular staffing levels were re-assessed in 2007 and it was determined that an increased component, particularly in engineering and maintenance, is required bringing the total regular staff headcount up to 650 in order to:

a) Reduce dependency on contractors: The ratio of IMS staff to contractors is considered a risk to IMS' ability to meet and deliver its high standards for safe, quality production on schedule during outage execution.

b) Maintain staffing consistency in work programs: IMS' experience has been that its reactor and delivery equipment maintenance programs are more successful in terms of minimizing critical path downtime when conducted by work crews who have benefited from experience gained through consistent involvement with the same type of work.

Inspection and Maintenance Services provides services to both internal and external customers and was established as a commercial business unit within OPG in 2002. Inspection and Maintenance Services supports OPG's work program needs for fuel channel, steam generator, and balance of plant inspections and specialized maintenance at Pickering A, Pickering B, and Darlington. Inspection and Maintenance Services also provides limited inspection services for OPG Fossil and Nuclear Waste Management.

Inspection and Maintenance Services main external customer is Bruce Power. Currently IMS has two service level agreements with Bruce Power to provide fuel channel and balance of plant inspection services. Inspection and Maintenance Services, from time to time, may enter into short-term agreements directly or indirectly with other non-OPG clients to provide inspection and maintenance services.

Inspection and Maintenance Services recovers its costs by charging its internal customers (e.g., OPG generation stations) for services at commercial rates that is consistent with how it charges for negotiated services to third parties such as Bruce Power. All net margin earned by IMS on the provision of inspection and maintenance services to internal and external customers is credited back to the nuclear cost of service.

Total revenues from IMS third party sales, primarily to Bruce Power, over the period 2005 - 2009 are shown in Ex. G2-T1-S1 Table 1 and cost of goods sold are discussed in section 3 below. In 2005, Bruce Power transferred steam generator inspection services from IMS to an original equipment manufacturer. As a result, the steam generator inspection services agreement with Bruce Power was amended in 2005.

The revenue lost from steam generator work was offset in 2006 by the commencement of the multi-year fuel channel repositioning and single fuel channel replacement work programs for Bruce Power, both of which were not included in the 2006 business plan. These programs do not occur frequently and represent a significant amount of revenue for IMS. Revenue from these programs was included in the 2007 plan.

From the onset of the external commercial work program, planning information for future programs from Bruce Power has been subject to change due to the variability of work programs. This can be seen in the decline in planned revenues in 2008 and 2009 relative to 2007. Historically, Bruce Power outage programs have frequently changed in scope and are subject to being rescheduled from year-to-year making it difficult to forecast future work programs and revenue with reasonable certainty during the five-year business planning process. Bruce Power is only obliged to show us a two year work forecast. Generally, the work program and revenue for the first year of the five year business plan will have the greatest reliability reflecting most current and up-to date planning information from Bruce Power, while the outer years have less certainty. The Bruce Power work programs and revenues for 2008 and 2009 provided in this application are based on the 2008 business plan forecast, and reflect current and up-to date planning information from Bruce Power.

3.0 OPERATING COSTS OF NUCLEAR NON-ENERGY BUSINESSES

The operating cost of the nuclear non-energy business are made up of direct costs (cost of goods sold) and indirect support costs. The direct costs are shown in Ex. G2-T1-S1 Table 1 on an aggregated basis. Indirect costs are discussed in the base OM&A exhibits.

3.1 Heavy Water

The cost of goods sold for heavy water sales covers the cost of direct labour involved in handling, testing, loading, unloading, packaging, cost of containers, and transportation costs. The cost of goods sold for detritiation services is an allocation of the TRF's operating and maintenance cost. The allocation is approximately proportional to the amount of processing capacity of the TRF facility dedicated to the provision of service to third parties, relative to provision of service to OPG nuclear units. The allocation factor represents a normalized TRF usage over time. TRF costs not allocated to third parties are part of nuclear base OM&A costs recovered in the nuclear revenue requirement. Shipments of heavy water by third parties to the TRF for processing are governed by the plant operations of the third party, plant operations of OPG and the availability of the TRF facility. Hence there are annual variations.

Indirect support costs relate to the Isotopes Sales Group dedicated to servicing this market and an allocation of Isotopes Sales Group management and support staff, all of which is captured in the Commercial Series Group within Nuclear base OM&A.

3.2 Cobalt-60

The cost of goods sold for this product includes installation, removal, processing, storage, and packaging. Cost of goods sold also includes a cost item for the long-term storage of the spent (but still radioactive) cobalt, as the third party agreement provides for the return of the spent cobalt to OPG (Nuclear Waste Management Division) for storage as nuclear waste.

There are some indirect support costs including allocation of sales and administration staff costs, which are captured in base OM&A (i.e., Commercial Services Group within Nuclear Generation Development and Services).

3.3 Tritium Sales

The cost of goods sold for the tritium sales program are primarily Atomic Energy of Canada Limited laboratory and dispensing fees, packaging, and shipping costs. The product itself is a pure by-product of the detritiation process that is required to reduce employee radiation exposure and no production cost is attached to what is sold. All shipments of tritium must conform to CNSC, and federal and provincial transportation regulations for safe handling and shipment of radioactive materials to minimize the hazard to those involved in the shipment, the public, and the environment

Indirect costs which are budgeted as Nuclear base OM&A (i.e., Commercial Services Group within Nuclear Generation Development and Services) represent an allocation of Isotopes Sales Group support costs including a portion of labour costs related to Isotopes Sales Group sales and administration.

3.4 Inspection and Maintenance Services

The IMS direct costs are comprised of internal and augmented labor, materials and expenses for executing the external work programs. Indirect costs are budgeted within Nuclear base OM&A (i.e., IMS group within Nuclear Generation Development and Services) and represent an allocation of administrative overheads for provision of IMS services for both internal and external customers.

4.0 NUCLEAR NON-ENERGY REVENUES AND PROPOSED REGULATORY TREATMENT

There are minimal growth opportunities for nuclear non-energy revenues from third party heavy water sales and processing, isotope sales and IMS services with the result that overall revenues and margins have been relatively stable over time. The majority of non-energy revenues and margin come from the provision of services to a single customer, Bruce Power. As discussed above, some opportunities may exist for increasing revenues and margin but also risks are emerging in the form of competitive pressures (e.g., high Canadian dollar impact on tritium and heavy water sales).

The derivation of the interim payment amount for nuclear commencing April 1, 2005 included all revenues (and associated direct costs as well as indirect costs as part of base OM&A) with respect to nuclear non-energy activities. Consistent with this past approach, OPG is proposing that all third party revenues (net of direct costs and indirect costs budgeted within base OM&A) related to heavy water sales, tritium removal services, isotope sales and IMS in the test period be recorded as an offset to the determination of the regulated payments amounts.

As shown in Ex. G2-T1-S1 Table 1, the proposed regulatory treatment represents a net contribution (before indirect costs) that reduces the prescribed payment amount by $36.6M in 2008 and $42.0M in 2009. Overall the nuclear non-energy businesses are profitable enterprises, inclusive of all costs.

While OPG is proposing in its first cost of services application the continuation of the methodology established for setting the interim payment amount, OPG believes that in a future proceeding there may be merit in pursuing alternative regulatory treatment for nuclear non-energy revenues, including consideration of some form of incentive profit sharing mechanisms.

5.0 PERIOD-OVER-PERIOD CHANGES

2006 Actual - 2009 Plan

Ex. G2-T1-S1 Table 1 sets out non-energy revenues by each business unit over the period 2005 - 2009. Period-over-period variance explanations are provided in Ex. G2-T1-S2.

Numbers may not add due to rounding.

Table 1

Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	NGD-Related Revenues:					
1	**Heavy Water Sales & Processing**	17.4	18.9	30.3	27.0	22.5
2	**Isotope Sales (Cobalt 60 + Tritium)**	7.2	11.0	7.0	9.3	9.6
3	**Inspection & Maintenance Services**	39.3	51.2	90.6	73.2	44.9
4	**Total NGD-Related Revenues**	63.9	81.0	127.9	109.5	76.9
5	**NGD-Related Direct Costs**	25.9	33.8	63.8	47.2	29.3
6	**NGD-Related Contribution Margin**	38.0	47.2	64.1	62.3	47.7
7	**Ancillary Services**[1]	2.8	3.1	2.8	3.0	3.1
8	**Other**[2]	0.6	2.7	1.7	0.2	0.1

1 Ancillary Services revenues for 2005 are for April 1, 2005 to December 31, 2005. Ancillary Services related to Nuclear prescribed facilities are discussed in Ex. G1-T1-S1.
The 2006 actuals are the reported numbers in OPG's financial statements based on estimates at year end.
The 2007 actuals are based on preliminary IESO statements. This number varies slightly from final IESO statements due to adjustments made after year end.

2 Other includes (i) revenue of $2.3M in 2006 and $0.6M in 2007 due to sale of spare parts and miscellaneous inventory by Nuclear Supply Chain, (ii) revenue $1.0 M from equipment rental in 2007 and (iii) revenue earned from services provided by Nuclear Programs and Training to an external party over the period 2005-2009.

COMPARISON OF NON-ENERGY REVENUES - NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of OPG Nuclear non-energy revenues.

2.0 OVERVIEW

Exhibit G2-T1-S2 Table 1 presents year-over-year comparisons of Nuclear non-energy revenues.

3.0 PERIOD-OVER-PERIOD CHANGES - TEST PERIOD

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

The 2009 planned contribution margin from non-energy operations ($47.7M) is forecast to be lower than 2008 plan ($62.3M) for the following reasons:

Inspection and Maintenance Services revenues decrease in 2009 relative to 2008, reflecting the reduction in demand from both outage and regular maintenance and inspection work for Bruce Power.

Heavy water sales and processing services in 2009 are lower than 2008 reflecting lower heavy water processing services requirements by Bruce Power.

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

The 2008 planned contribution margin from non-energy operations ($62.3M) is forecast to be lower than 2007 actual ($64.1M) for the following reasons:

The reduction in 2008 Inspection and Maintenance Services (“IMS”) revenues relative to 2007 is due to the completion of major project work in 2007 partially offset by the inclusion of new inspection forecasted demand from Bruce Power in 2008.

With respect to heavy water sales and processing services, forecast 2008 revenues are slightly lower than 2007 actual. This is due primarily to a one time heavy water sale to a nuclear energy company based in China in 2007 that is not forecast to continue in the test period (China will use the heavy water for reactor loss make-up over the next four years). This is offset by higher heavy water processing services in 2008.

With respect to isotope sales, forecast 2008 revenues are slightly higher than 2007 actual. In 2007, cobalt-60 sales are below average primarily because of timing of outages, i.e., planned outages are on a two-year cycle and only three Pickering reactors within the OPG combined nuclear fleet produce cobalt. Every two years cobalt is harvested during a reactor outage and shipped to customers. The outage plan and timing determines how much cobalt is shipped in any one year. For planning purposes OPG forecasts the average of the two years (one year two outages, second year one outage). In 2006 two cobalt-60 harvests during outages were shipped resulting in less cobalt-60 being available in 2007. Forecast 2008 tritium sales are also slightly higher reflecting anticipated higher sales of tritium as the International Fusion Research project, located in France, initiates research.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2007 Actual versus 2007 Budget

The 2007 actual contribution margin from non-energy operations ($64.1M) was higher than the 2007 budget ($49.6M), for the following reasons:

Inspection and Maintenance Services actual 2007 revenues are higher than 2007 budget primarily due to recovery of charges from Bruce Power for deferring a 2007 Spring outage to the Fall after mobilization, preparatory work, and training had been completed. A further 10 day delay in the Fall outage resulted in more charges paid by Bruce Power. There was also additional 2007 non-budgeted revenue for heat transport system manual drain work.

The 2007 actual heavy water sales and processing services revenues are higher than budget primarily due to a one-time heavy water sale to a nuclear energy company based in China, higher than planned heavy water sales to “traditional” non-nuclear customers servicing the medical and pharmaceutical fields (nuclear magnetic resonance and deuterated compounds) and processing services to utility customers.

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

The 2007 actual contribution margin from non-energy operations of $64.1M was higher than in 2006 ($47.2M). This was due to increased revenue from heavy water processing services to Bruce Power, higher tritium sales, increased IMS services offset by lower cobalt-60 sales.

Actual 2007 heavy water processing services revenues are higher than 2006 due to longer than planned TRF outage in 2006 (unavailability of TRF to process heavy water). Tritium sales are also slightly higher reflecting anticipated higher sales of tritium as the International Fusion Research project, located in France, initiates research.

Actual 2007 IMS revenues are higher compared to actual2006 primarily due to incremental revenue from fuel channel maintenance work and recovery of charges from Bruce Power for deferring a 2007 Spring outage to the Fall after mobilization, preparatory work, and training had been completed. A further 10 day delay in the Fall outage resulted in more charges paid by Bruce Power. There was also additional 2007 revenue for heat transport system manual drain work.

A large volume of cobalt-60 was harvested and shipped in 2006 during the outage periods resulting in less cobalt-60 available in 2007. At the same time, certain direct costs associated with the 2006 cobalt-60 harvest were not recorded in 2006 and will instead be accounted for in 2007.

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL YEARS

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

Actual IMS and cobalt-60 sales in 2006 exceeded budget.

In 2006, IMS revenues were higher than budget due to an unplanned increase in work related to Bruce fuel channel repositioning and single fuel channel replacement preparations and additional maintenance requirements. These increases were offset partially by decreased revenue for a cancelled Bruce outage.

2006 cobalt-60 revenues are higher than budgeted primarily because of timing, i.e., a large volume of cobalt-60 was harvested and shipped in 2006 during the outage periods resulting in less cobalt-60 projected to be available in 2007 and more harvested than budgeted in 2006. At the same time, certain actual direct costs associated with the 2006 cobalt-60 harvest were not recorded in 2006 and will be instead accounted for in 2007.

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

Actual heavy water sales/processing revenues, isotope sales revenues, and IMS revenues were higher in 2006 compared to 2005. The reasons for the positive variances are:

- Higher heavy water processing services to utility customers and higher heavy water sales to "traditional" customers.
- 2006 cobalt-60 revenues are higher than 2005 cobalt-60 revenues primarily because of timing, i.e., a large volume of cobalt-60 was harvested and shipped in 2006 during the outage periods. At the same time, certain actual direct costs associated with the 2006 cobalt-60 harvest were not recorded in 2006 and will be instead accounted for in 2007.
- Additional IMS revenues due to more increased outage work. Non-outage work also increased in 2006 compared to that in 2005.

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

Actual heavy water sales/processing and IMS revenues in 2005 exceeded budget, while isotope sales were slightly less than budget. The reasons for the variances are:

- Higher heavy water processing services to Bruce Power due to availability of TRF.
- Lower than budgeted tritium sales and revenue due to offshore price competition. Lower sales volumes resulted in lower direct costs. Also lower direct costs due to the deferral of cobalt-60 harvesting to 2006.
- Additional IMS revenues due to more than budgeted outage work for Bruce Power.

Numbers may not add due to rounding.

Table 1

Comparison of Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NGD-Related Revenues:									
1	**Heavy Water Sales & Processing**	14.9	2.5	17.4	1.5	18.9	(0.0)	18.9	11.4	30.3
2	**Isotope Sales (Cobalt 60 + Tritium)**	7.6	(0.4)	7.2	3.8	11.0	1.2	9.8	(4.0)	7.0
3	**Inspection & Maintenance Services**	29.0	10.3	39.3	11.9	51.2	13.8	37.4	39.4	90.6
4	**Total NGD-Related Revenues**	51.5	12.4	63.9	17.1	81.0	15.0	66.1	46.8	127.9
5	**NGD-Related Direct Costs**	23.6	2.3	25.9	7.9	33.8	8.9	24.9	30.0	63.8
6	**NGD-Related Contribution Margin**	27.9	10.1	38.0	9.2	47.2	6.1	41.2	(22.9)	64.1
7	**Ancillary Services[1]**	1.9	1.0	2.8	0.3	3.1	0.6	2.5	(0.3)	2.8
8	**Other[2]**	0.2	0.4	0.6	2.1	2.7	2.5	0.2	(1.0)	1.7

Line No.	Revenue Source	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	NGD-Related Revenues:							
9	**Heavy Water Sales & Processing**	19.5	10.7	30.3	(3.2)	27.0	(4.6)	22.5
10	**Isotope Sales (Cobalt 60 + Tritium)**	6.8	0.2	7.0	2.3	9.3	0.3	9.6
11	**Inspection & Maintenance Services**	66.0	24.6	90.6	(17.4)	73.2	(28.3)	44.9
12	**Total NGD-Related Revenues**	92.3	35.5	127.9	(18.4)	109.5	(32.5)	76.9
13	**NGD-Related Direct Costs**	42.8	21.0	63.8	(16.6)	47.2	(17.9)	29.3
14	**NGD-Related Contribution Margin**	49.6	14.5	64.1	(1.8)	62.3	(14.6)	47.7
15	**Ancillary Services[1]**	3.0	(0.2)	2.8	0.2	3.0	0.1	3.1
16	**Other[2]**	0.2	1.5	1.7	(1.5)	0.2	(0.1)	0.1

1 Ancillary Services revenues for 2005 are for April 1, 2005 to December 31, 2005. Ancillary Services related to Nuclear prescribed facilities are discussed in Ex. G1-T1-S1.
The 2006 actuals are the reported numbers in OPG's financial statements based on estimates at year end.
The 2007 actuals are based on preliminary IESO statements. This number varies slightly from final IESO statements due to adjustments made after year end.

2 Other includes (i) revenue of $2.3M in 2006 and $0.6M in 2007 due to sale of spare parts and miscellaneous inventory by Nuclear Supply Chain, (ii) revenue $1.0 M from equipment rental in 2007 and (iii) revenue earned from services provided by Nuclear Programs and Training to an external party over the period 2005-2009.

BRUCE GENERATING STATION - REVENUES AND COSTS

1.0 PURPOSE

The purpose of this evidence is to discuss the revenues earned by OPG under the Bruce Lease Agreement entered into on May 12, 2001 between Bruce Power L. P. ("Bruce Power") and OPG, as further amended the "Bruce Lease" as well as revenues earned from agreements associated with the Bruce Lease, and the related costs OPG incurs with respect to the Bruce Generating Stations.

2.0 OVERVIEW OF BRUCE LEASE AND ASSOCIATED AGREEMENTS

Paragraphs 6 (2) 9 and 6 (2) 10 of O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Generating Stations, and that any revenues earned from the Bruce Lease Agreement in excess of cost be used to offset the nuclear payment amounts.

Effective May 12, 2001, as part of a decontrol initiative, OPG leased its Bruce A and Bruce B Generating Stations and associated lands and facilities to Bruce Power. A description of the Bruce site and the facilities for which Bruce Power, as the tenant of the leased premises, assumed full care and control as well as those properties within the Bruce site boundaries that OPG retained, can be found at Appendix A.

The Bruce Lease sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power (including lease payment). As the tenant of the leased premises, Bruce Power is responsible for full care and control of the Bruce site, except for those land and facilities within the site boundaries retained by OPG. The initial term of the Bruce Lease is to December 31, 2018.

In association with the Bruce Lease, OPG and Bruce Power have entered into a number of agreements in regard to the provision of services by OPG to Bruce Power, or from Bruce Power to OPG. The following summarizes the Lease Agreement and those related agreements which have revenue and/or cost implications for OPG:

1. Lease Agreement: Bruce Power, as the tenant of the leased premises, pays to OPG in monthly installments an annual rent consisting of a predetermined base component and a variable supplemental component. The base rent is set out in the Lease Agreement and fixed for each year of the lease. The supplemental unit rate is currently in the order of $28M per unit per year (in 2006 dollars) and is applied on the basis of the number of generating units operational in a given calendar year, currently four Bruce B and two Bruce A generating units. The supplemental unit rate is escalated annually by the consumer price index (Ontario). The base and supplemental lease payment amounts are set out in section 3.0 below.

   In association with the closing of the lease transaction with Bruce Power, OPG received initial payments totaling $595M. The initial payments consisted of $370 million in cash proceeds and a $225 note receivable, which was subsequently collected by OPG in 2003. According to a directive from the Province, the proceeds from the note receivable and applicable interest were to be applied against OPG's funding requirements under the Ontario Nuclear Funds Agreement ("ONFA") with respect to its nuclear liabilities by March 2008. OPG made this one-time contribution in the amount of $334M (referred to as the "Bruce Extraordinary Payment") in December 2007. The implications of this one-time contribution on ONFA are discussed in Ex. H1-T1-S1. The implications of this contribution on income taxes are discussed in Ex. F3-T2-S1.

   The initial payments of $595M less the value of net assets transferred to Bruce Power under the lease agreement were recorded as deferred revenue in the amount of $213M. This deferred revenue is being amortized at an amount of $11.7M per year over the initial lease term of approximately 18 years and is recorded as revenue.

   In October 2005, OPG was directed by its shareholder to make further amendments to the Bruce Lease in connection with the refurbishment and return-to-service of Bruce A Units 1, 2, and 3. Bruce A Units 1 and 2 are not currently in operational service, and have not been since Bruce Power assumed the control of the Bruce Generating Stations in May 2001. The October 2005 amendments to the Bruce Lease provide that upon completion of the refurbishment and the declaration of operational service of Bruce A Unit 1 and/or Unit 2 in accordance with the terms of an agreement between Bruce Power and the Ontario Power Authority, the annual supplemental rent per unit per year will be approximately $5.6M (in 2002 dollars), to be escalated by the annual change in the consumer price index (Ontario). Bruce A Unit 3 is currently operational and will be shutdown some time in the future in order to be refurbished. Upon the future return-to-service of Unit 3, the supplemental rent will also be approximately $5.6M/year (in 2002 dollars), escalated by the annual change in the consumer price index (Ontario) following the first year that the refurbished Unit 3 is in operational service. The test year supplemental rent forecast assumes no revenue impact in 2008 or 2009 due to the refurbishment and return to service of the currently non-operational Units 1 and 2, and the shutdown for refurbishment of Unit 3.

The October 2005 amendments did not address the supplemental rent for Bruce A Unit 4, which is also currently operational. This was because Bruce A Unit 4 was not to be refurbished to the same extent as Bruce A Units 1, 2, and 3. In August 2007, Bruce Power and the OPA announced an amendment to their agreement to provide for a shutdown and full refurbishment of Bruce A Unit 4 to commence some time after the test period. However, there have been no further amendments to the Bruce Lease in respect of the Bruce A Unit 4 refurbishment.

2. Used Fuel Waste and Cobalt-60 Agreement: Under the Used Fuel Waste and Cobalt-60 Agreement, OPG provides used fuel management and storage services to Bruce Power for the used nuclear fuel generated in the Bruce A and Bruce B reactors. OPG holds the long-term responsibility for the used nuclear fuel, as well as the responsibility for the eventual decommissioning of the site and its facilities after the lease expires or is terminated. Also, OPG retains the obligation to provide the financial guarantees for the decommissioning of licensed facilities as required by the Canadian Nuclear Safety Commission (see Ex. H1-T1-S1). The base and supplemental rent payments under the Lease Agreement include compensation for the used fuel waste management/storage services and the decommissioning.

Under the Used Fuel Waste and Cobalt-60 Agreement, OPG has accepted liability for the interim storage and future disposal of Bruce Power's spent cobalt-60, and in return OPG receives payments from Bruce Power as set out in section 3.0 below.

3. Low and Intermediate Level Waste Agreement: OPG has the obligation for managing (i.e., collecting, storing, and disposal) low-level and intermediate-level radioactive waste generated by Bruce Power and in return Bruce Power pays OPG a fee for the provision of low-level and intermediate-level radioactive waste services. The fee is volume based, escalated annually by the consumer price index (Ontario), and determined on the basis of OPG's estimated future costs of managing the low-level and intermediate-level waste generated by Bruce Power.

   In March 2007, a Supplemental Agreement To Low and Intermediate Level Waste Agreement (the "Supplemental Agreement") was entered into between OPG and Bruce Power related to new waste generated during the refurbishment of Bruce A Units 1 and 2. The Supplemental Agreement requires OPG to manage low-level and intermediate-level radioactive waste (i.e., steam generators and pressure tubes) generated by Bruce Power as a result of the refurbishment. Bruce Power pays OPG a fee determined on the basis of OPG's estimated future costs of managing the incremental volume of waste received under the Supplemental Agreement.

   Revenues from the Low and Intermediate Level Waste Agreement and the Supplemental Agreement are set out in section 3.0 below.

4. Heavy Water and Associated Services Agreement: As discussed at Ex. G2-T1-S1, Bruce Power and OPG have entered into an agreement for the provision of heavy water detritiation services by OPG to remove radioactive tritium from the heavy water inventory in Bruce Power's possession. Revenues (and related costs) associated with the provision of heavy water and associated services are discussed in detail as part of Nuclear Non-Energy Revenues found in Ex. G2-T1-S1.

5. Inspection and Maintenance Services ("IMS"): As discussed in Ex. G2-T1-S1, there is a Reactor Fuel Channel Inspection and Maintenance Services Agreement and the Steam Generator and Special Inspection and Maintenance Services Agreement for the provision of inspection and maintenance services to be provided by OPG, on a commercial basis, of the Bruce A and Bruce B station systems and equipment. These operating agreements are subject to termination by either party upon due notice. Revenues (and related costs) associated with the provision of IMS are discussed in detail as part of Nuclear Non-Energy Revenues found in Ex. G2-T1-S1.

6. Bruce Site Services Agreement: This agreement provides for various support and maintenance services that are provided by OPG to Bruce Power, and by Bruce Power to OPG, on a cost recovery basis. The majority of the services are provided by Bruce Power to OPG. The services contemplated by this agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. Some examples of site services provided by OPG to Bruce Power include landfill services, inventory and material storage, and transportation of non-waste radioactive material. Some examples of site services provided by Bruce Power to OPG include scaffolding services, sewage and storm sewer services, snow removal services, site security and emergency response services, radiation detection services, bus and winter storm transportation services, and maintenance of OPG transport and work equipment.

   Site service revenues are set out in section 3.0 and related costs are discussed in section 4.1.

7. Nuclear Operations Support and Services and Transitional Technical Support and Services Agreement: During the initial transitional phase when Bruce Power commenced operations under the Bruce Lease, OPG provided engineering and other technical support services. While this agreement is still active, services and related revenues are minimal (less than $100K) and none are forecast in 2009.

8. Telephone, Public Address, and Fibre Optic Services Agreement: Under this agreement, Bruce Power procures, as agent for OPG, phone services from third parties and provides public address and fibre optic cable services to OPG within and between the OPG facilities at the Bruce site. The costs incurred under this agreement are discussed in section 4.2.

9. Construction Retube Building and Buildings B17/B21 Agreement: This memorandum of agreement relates to the relocation by Bruce Power of OPG's IMS group from within a centralized Bruce A facility to alternate Bruce Power facilities and to an OPG building. To compensate OPG for incremental costs associated with the relocation, Bruce Power provides to OPG annual financial reimbursement as discussed in section 4.2.

10. Demolition and Clean-up Obligations: As the landlord, OPG has a contractual responsibility for the decommissioning, demolition and environmental remediation, as may be required, of certain structures and sites as specified within the Lease Agreement and particularly associated with the out of service Bruce Heavy Water Plant. OPG bears all costs of discharging these obligations, as discussed in section 4.2.

3.0 REVENUES FROM BRUCE LEASE AND ASSOCIATED OPERATING AGREEMENTS

There are actual and forecast revenue implications with respect to the Bruce Lease, the Used Fuel Waste and Cobalt-60 Agreement, the Low-Level and Intermediate-Level Waste Agreement (including the Supplemental Agreement), the Heavy Water and Associated Services Agreement, the Inspection and Maintenance Services Agreements, the Bruce Site Services Agreement, and the Nuclear Operations Support and Services and Transitional Technical Support and Services Agreement. Actual revenues earned by OPG for 2005 - 2007, and forecast revenues for 2008 and 2009, associated with the Bruce Lease and the associated agreements are summarized in Ex. G2-T2-S1 Table 1.

Revenues remain relatively stable over the period 2005 - 2009. The one exception is the increase in 2007 actual and 2008 forecast revenues for low and intermediate-level radioactive waste services being primarily due to revenues received under the Supplemental Agreement from Bruce Power related to the refurbishment of Bruce A Units 1 and 2. No waste and therefore no revenues are forecast under the Supplemental Agreement in 2009.
The revenues associated with the Supplemental Agreement were also not included in the 2007 and 2008 budgeted amounts as per OPG's business plan for years 2007 - 2009 established in 2006.

4.0 COSTS FROM BRUCE LEASE & ASSOCIATED OPERATING AGREEMENTS

As noted, section 6 (9) of O. Reg. 53/05 provides that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Generating Stations. The costs to be recovered in the test period with respect to the Bruce Generating Stations for the purpose of this exhibit have been separated between those cost components ("Bruce Direct Costs") referenced in this exhibit for recovery in the nuclear revenue requirement, and those other costs incurred by OPG with respect to the Bruce Generating Station that are described elsewhere in the evidence for recovery in the nuclear revenue requirement ("Other Costs").

4.1 Bruce Direct Costs

The following summarizes the Bruce Direct Costs:

1. Depreciation: Depreciation is derived by reference to the fixed assets owned by OPG at the Bruce site. The Bruce fixed asset values of the leased facilities, as set out in Ex. G2-T2-S1 Table 2, include:
    - Assets leased to Bruce Power (e.g., the Bruce A and B Generating Stations) and the fixed asset value associated with the nuclear liabilities relating to these stations. For accounting and revenue requirement purposes the nuclear liabilities associated with the assets leased to Bruce Power have been treated in a fashion similar to the Nuclear Liabilities associated with other nuclear stations owned and operated by OPG (see Ex. H1-T1-S2 for a description of revenue requirement treatment of the nuclear liabilities).
    - Assets retained by OPG at the Bruce site include the lands and facilities associated

with both conventional industrial waste and radioactive waste storage, as well as the lands associated with the now demolished heavy water plant and that are being remediated or monitored in accordance with environmental regulations.

The depreciation forecast was determined based on the Bruce fixed asset values derived from the 2007 audited financial statements, adjusted for fixed asset additions to determine figures for 2008 and 2009. OPG applied the depreciation methodology described in Ex. F3-T2-S1 to derive the depreciation expense and related accumulated depreciation for each year.

Also, as noted at Ex. H1-T1-S2, variable expenses related to incremental volumes of nuclear low-level and intermediate-level waste are charged to depreciation expense. The forecast of depreciation expense set out in Ex. G2-T2-S1 Table 3 includes $11.3M in 2008 and $1.5M in 2009 for the variable costs of processing, storage and management of low-level and intermediate-level waste expected to be produced by Bruce Power.

Variable expenses related to incremental quantities of used nuclear fuel bundles generated by the Bruce Generating Stations are captured separately in Ex. G2-T2-S1 Table 3 as discussed below under used fuel waste storage and disposal costs.

2. Property Tax: Per the provisions of the Bruce Lease, OPG pays the property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments in lieu of property tax to the Ontario Electricity Financial Corporation, as described in Ex. F3-T2-S1.

3. Ontario Capital Tax ("OCT"): OPG is subject to OCT at the applicable rate on its taxable capital subject to the general capital tax deduction. For revenue requirement purposes, average fixed asset values associated with the Bruce facilities, as set out in Ex. G2-T2-S1 Table 2, are used as the basis for calculating OCT related to the Bruce facilities, as

4. presented in Ex. G2-T2-S1 Table 4. A further description of OCT can be found at Ex. F3-T2-S1.

5. Interest: Interest is derived by reference to the net book value of fixed assets as set out in Table 2. The debt ratio and cost of debt used, as set out in Ex. G2-T2-S1 Table 5, is the same as for the prescribed assets.

6. Return on Equity ("ROE"): ROE is based on the book value of fixed assets (see Ex. G2-T2-S1 Table 2). The equity ratio and cost of equity used, as set out in Ex. G2-T2-S1 Table 5, are the same as for the prescribed assets.

7. Used Fuel Waste Storage and Disposal Costs: Set out in Ex. G2-T2-S1 Table 3, for recovery in the nuclear revenue requirement are the variable costs associated with storing and disposing incremental used nuclear fuel produced by Bruce Power. In that regard, Ex. H1-T1-S2 notes that variable costs associated with incremental quantities of used fuel generated by OPG's other nuclear stations are recovered as a component of the fuel expense for the period. Similarly, variable costs associated with used nuclear fuel produced by the Bruce stations is being recovered in the period incurred.

4.2 Other Costs

Other costs related to the Bruce Generating Stations which are captured elsewhere in the evidence for purposes of determining the nuclear revenue requirement are:

1. Costs Related to Working Capital: Working capital related to the Bruce Lease and associated operating agreements are a component of OPG Nuclear's overall working capital, as set out in the lead/lag study at Ex. B4-T1-S1.

2. Regulatory Income Taxes: Earnings from the Bruce Lease and related operating agreements are taxable. The revenues and costs from the Bruce Lease and associated agreements are included in the calculation of income taxes attributed to the prescribed assets and income taxes are included in the determination of Nuclear's revenue requirement Ex. F3-T2-S1.

3. Corporate Support Costs: OPG corporate groups provide support services related to the management of the Bruce Lease and associated agreements. The costs of such support services are captured within the allocation of corporate support costs to Nuclear as discussed at Ex. F3-T1-S1. Examples of support services would include Real Estate Services, Contract Administration and Billing Services provided by OPG's corporate functions. Other contract management services (e.g., contract interpretation, negotiation, and amendments) of the Bruce Lease and associated agreements are included in nuclear base OM&A (i.e., within Nuclear Generation Development and Services - Commercial Services in Ex. F2-T2-S1).

4. Heavy Water Sales and Associated Services/IMS Services Agreement: Costs incurred by OPG with respect to the provision of services to Bruce Power under the Heavy Water and Associated Services Agreement and the IMS Agreements are discussed and set out in the section on non-energy revenues Ex. G2-T1-S1.

5. Bruce Site Services Agreement: As noted above, OPG both provides to and receives from Bruce Power services under the Bruce Site Services Agreement on a cost recovery basis. Costs incurred by OPG to provide site services to Bruce Power are captured in the budgets of those departments providing such services. Depending upon the nature of the costs incurred by OPG for the receipt of site services from Bruce Power, costs are (1) incurred by corporate functions (i.e., Real Estate) to be allocated to Nuclear using the corporate cost allocation methodology described in Ex. F3-T1-S1, (2) directly charged against the nuclear liabilities, or (3) directly incurred by a specific business division in Nuclear (e.g., some Bruce site service costs are recorded as IMS indirect costs as set out in Ex. F2-T2-S1 Nuclear base OM&A).

6. Telephone, Public Address, and Fibre Optic Services Agreement: Bruce Power invoices for the provision of telephone and data transmission services are paid directly by OPG’s Chief Information Office and are a component of the corporate support costs allocated to nuclear as discussed at Ex. F3-T1-S1.

7. Construction Retube Building and Buildings B17/B21 Agreement: Bruce Power credits related to this agreement are captured within the Real Estate corporate function as an offset to annual on site operating and maintenance costs and are a component of the corporate support costs allocated to nuclear as discussed at Ex. F3-T1-S1.

8. Demolition and Clean-up Obligations: The costs incurred for demolition and environmental remediation of the unused buildings and sites are minimal and recovered through the Bruce depreciation expense described in Section 4.1 above.

4.3 Bruce Direct Costs and Variance Explanations 2005 - 2009

Ex. G2-T2-S1 Table 3 sets out actual Bruce Direct Costs incurred by OPG for 2005 - 2007 and forecast Bruce Direct Costs for 2008 and 2009.

The main drivers for the variances in Bruce Direct Costs over the period 2005 - 2009 are:

- Depreciation: The derivation of depreciation expense for the Bruce facilities is impacted by the fixed asset value, the expected service life of the asset and variable expenses related to low-level and intermediate-level waste. As shown in Ex. G2-T2-S1 Table 3, OPG experienced a significant increase in depreciation expense between 2006 and 2007 actuals primarily due to the higher variable expenses related to nuclear low-level and intermediate-level waste (discussed below). The higher variable expenses were partially offset by the impact of the extension in the expected service life, for accounting purposes, of the Bruce B Generating Station effective January 1, 2007 (discussed in Ex. F3-T2-S1). The increase in the fixed asset values of the Bruce facilities on December 31, 2006 (shown in Ex. G2-T2-S1 Table 2), which resulted from the net increase in the nuclear liabilities on December 31, 2006 did not have a significant impact on depreciation expense for the Bruce facilities in 2007. The net increase in the nuclear liabilities associated with the Bruce facilities comprised an increase for the Bruce A Generating Station and a reduction for the Bruce B Generating Station. The impacts on depreciation expense of the Bruce A increase and the Bruce B reduction were largely offsetting.

For 2008 and 2009, depreciation expense is expected to decrease as a result of lower variable expenses related to nuclear low-level and intermediate-level waste (as discussed below) and the extension of estimated service lives, for accounting purposes, of both Bruce A and Bruce B Generating Stations effective January 1, 2008 (discussed in Ex. F3-T2-S1).

As discussed in section 3.0 and noted in Ex G2-T2-S1 Table 3, depreciation expense includes variable nuclear low-level and intermediate level waste management expenses. OPG incurred additional waste management expenses in 2007 and forecasts further expenses in 2008 due to the receipt of low-level and intermediate-level waste from Bruce Power related to the refurbishment of Bruce A Units 1 and 2 under the Supplemental Agreement to Low and Intermediate Level Waste Agreement discussed in section 2.0. No waste is currently expected to be received beyond 2008. The variable expenses associated with the Supplemental Agreement were also not included in the 2007 and 2008 budgeted amounts as per OPG's business plan for years 2007 - 2009 established in 2006.

- Property Tax: Actual and forecast property tax expense remains relatively consistent over the period 2005 - 2009. The 2007 budgeted property tax expense was higher than the 2007 actual property tax expense primarily due to the 2007 budget incorporating increases in anticipation of an amendment to O. Reg. 224/00 under the *Electricity Act 1998* (discussed in Ex. F3-T2-S1), which did not occur.

- Ontario Capital Tax: The actual 2007 OCT is higher compared to the 2006 actual primarily as a result of the increase in the fixed asset value of the leased facilities as shown in Ex. G2-T2-S1 Table 2, partially offset by the reduction in the applicable OCT rate in 2007. The OCT is expected to remain relatively consistent in 2008 and 2009.

- Interest Expense: The increase in 2007 actual interest compared to 2006 actual interest is due to impact of the increase in the fixed asset value for the leased facilities as a result of the increase in the nuclear liabilities associated with Bruce Generating Stations.

The decline in 2008 budget interest compared to 2007 actual interest reflects: 1) a decline from 55 percent to 42.5 percent in the debt ratio for the prescribed assets as set out in Ex. C1-T2-S1, 2) a slight decline in the fixed asset value of the leased facilities due to depreciation, and 3) an offsetting increase in the forecast interest rate to 5.76 percent.

- Return on Equity: The increase in 2007 actual ROE compared to 2006 actual ROE is due to impact of the increase in the fixed asset value for the leased facilities as a result of the increase in the nuclear liabilities associated with Bruce Generating Stations.

The increase in the 2008 budget ROE compared to 2007 actual ROE reflects: 1) the increase in OPG's requested return on equity from five percent to the proposed 10.50 percent for the prescribed assets, 2) an increase in the equity ratio from 45 percent to 57.5 percent, consistent with the capital structure and ROE used for the prescribed assets, and 3) an offsetting slight decline in the fixed asset value of the leased facilities for depreciation.

LIST OF ATTACHMENTS

APPENDIX A

Bruce Site

The Bruce site consist of two nuclear generating stations and associated lands and facilities leased by OPG to Bruce Power as of May 12, 2001, together with certain lands and facilities that have been retained by OPG for its nuclear waste management operations. The Bruce site is located approximately 200 kilometers northwest of Toronto in the Municipality of Kincardine on the shore of Lake Huron.

The two generating stations are the Bruce B Generating Station consisting of four operational units and the Bruce A Generating Station also consisting of four units, two of which (Units 3 and 4) are operational and two of which (Units 1 and 2) are currently undergoing a major refurbishment.

Bruce Power assumed operations of the Bruce A Generating Station and the Bruce B Generating Station, the associated lands and facilities required to support and service the two generating stations, and the perimeter security fence that encompasses the Bruce site as a whole. Within the site perimeter fence, the lands and facilities associated with conventional waste storage and radioactive waste handling and storage were retained by OPG. OPG also retained care and control of the lands and facilities associated with an out of service heavy water plant which has been partially demolished and is presently in a state of environmental remediation and/or monitoring in accordance with regulatory requirements. Hydro One has assigned easements to provide for access to and maintenance of its switchyards and transmission corridors located on both the Bruce Power leased premises and the OPG retained lands. The division of the site property, including all easement rights, is detailed with reference to registered land survey plans within the Bruce Lease.

Numbers may not add due to rounding.

Table 1
Bruce Lease Revenues ($M)

Line No.	Revenue Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Site Services (OPG to Bruce Power)**	0.5	0.4	0.5	0.5	0.6
2	**NOSS Technical & Engineering Services**	1.6	0.0	0.0	0.0	0.0
3	**Low & Intermediate Level Rad-Waste Services**	6.8	9.2	47.3	18.7	11.5
4	**Cobalt 60**	0.6	0.3	0.3	0.5	0.5
5	**Total Services**	9.5	9.9	48.1	19.7	12.6
6	**Fixed (Base) Rent**	67.0	69.0	71.0	72.0	74.0
7	**Supplemental Rent**[1]	164.6	169.6	170.1	173.7	177.5
8	**Amortization of Prepaid Rent**	11.7	11.7	11.7	11.7	11.7
9	**Total Rent**	243.3	250.3	252.8	257.4	263.2
10	**Total**	252.8	260.2	300.9	277.1	275.8

1 Variable supplemental rent approximately $28M per unit, per year escalated by projected CPI (Ontario) of 1.8% for 2008 and 2.0% for 2009.

Numbers may not add due to rounding.

Table 2
Bruce Fixed Assets ($M)

Line No.	Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Opening Book Value**	582.3	491.6	1,270.7	1,194.6	1,128.4
2	**Closing Book Value**	491.6	1,270.7	1,194.6	1,128.4	1,063.2
3	**Average Fixed Assets**[1]	537.0	442.2	1,232.6	1,161.5	1,095.8
	((line 1+line 2)/2)					

1 The December 31, 2006 closing book value includes an increase recorded at the end of the year related to the Nuclear Liabilities. An adjustment was made to exclude this increase from the calculation of the 2006 Average Fixed Assets, since the increase was recorded on December 31, 2006. For 2007, the calculation of the Average Fixed Assets includes the impact of this increase.

Numbers may not add due to rounding.

Table 3

Bruce Direct Costs ($M)

Line No.	Cost Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Depreciation**[1, 2]	99.8	100.4	120.6	77.5	66.7
2	**Property Tax**	11.4	13.3	13.8	15.2	15.5
3	**Capital Tax**[2]	1.6	1.3	2.8	2.6	2.5
4	**Interest**[2]	16.9	13.3	37.6	28.4	27.6
5	**Return on Equity**[2]	12.1	9.9	27.7	70.1	66.2
6	**Used Fuel Storage and Management**[2]	14.0	16.1	13.3	14.1	14.8
7	**Total**	155.8	154.4	215.8	208.0	193.2

1 Includes nuclear waste management variable expenses (2005 Actual - $1.4M, 2006 Actual - $1.3M, 2007 Actual - $44.5M, 2008 Plan - $11.3M, 2009 Plan - $1.5M)

2 For 2007 Actual, includes amounts deferred in the Nuclear Liability Deferral Account discussed in Ex. J1-T1-S1.

Numbers may not add due to rounding.

Table 4
Calculation of Ontario Capital Tax - Bruce ($M)
Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Particulars	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Average Fixed Assets**	537.0	442.2	1,232.6	1,161.5	1,095.8
2	**Less: Provincial Exemption**	0.5	0.6	1.4	1.4	1.3
3	**Net Taxable Capital**	536.4	441.6	1,231.2	1,160.1	1,094.5
4	**Ontario Capital Tax Rate**	0.300%	0.300%	0.225%	0.225%	0.225%
5	**Total Capital Tax**	1.6	1.3	2.8	2.6	2.5

Numbers may not add due to rounding.

Table 5

Bruce - Interest and Return on Equity Costs ($M)

Line No.	Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Average Fixed Assets**	537.0	442.2	1,232.6	1,161.5	1,095.8
2	**Debt Ratio**	55.0%	55.0%	55.0%	42.5%	42.5%
3	**Equity Ratio**	45.0%	45.0%	45.0%	57.5%	57.5%
4	**Interest Rate**	5.71%	5.48%	5.54%	5.76%	5.92%
5	**ROE**	5.00%	5.00%	5.00%	10.50%	10.50%
6	**Interest**	16.9	13.3	37.6	28.4	27.6
7	**Return on Equity**	12.1	9.9	27.7	70.1	66.2