Energy Probe Interrogatory #1

Ref: Ex. D2-T1-S 2, page 8

Issue Number: 3.5
Issue: Is the additional capital spending (beyond the levels being recovered under section 6(2)4)) appropriate?

Interrogatory

Page 8 of Schedule 2 is a project summary to "Improve Maintenance Facilities at Darlington". In the Project Need section of the summary the following statement appears:

> "This project is designed to address the current inadequate maintenance facilities at Darlington which are leading to overcrowding, inefficiencies, outage extensions, and non-code compliant work areas."

Please explain what conditions have caused the original maintenance facilities to become inadequate.

Response

The original maintenance facilities have become inadequate due to: 1) increased maintenance requirements 2) new maintenance strategies 3) loss of previously designated facilities 4) code compliance issues and 5) emerging functional requirements. Additional details on each item are provided below.

1) Increased Maintenance Requirements: Maintenance requirements have increased as Darlington progresses through its life cycle. In response to increased demands, maintenance staff levels at Darlington have increased by over 160 personnel since the plant was commissioned. In addition, Darlington originally had no provision for adequate breaker and relay maintenance. Technology-driven requirements include new maintenance facilities such as a reactor maintenance shop. Currently, these functions are performed in a temporary building with inadequate space, no permanent services and, in the case of the reactor maintenance, an underrated floor loading capacity.

2) Maintenance Strategy: Consistent with industry best practice, maintenance work is now being focused on day crews as opposed to shift crews. Hence, the total accumulated crew size on days has increased. In addition, OPG has identified the need for specialized maintenance crews (e.g. 'Fix-It-Now' crews and predictive maintenance crews), with a consequent requirement for additional shop space. Fix-It-Now crews allow optimization of corrective maintenance work by allowing some repairs to be completed without addition to the regular detailed work schedule. Predictive maintenance crews use techniques like oil sample analysis, clearance measurements,

thermography measurements, etc to allow maintenance to be completed prior to component failures, thereby increasing system reliability.

3) Loss of Previously Designated Facilities: Certain offices and maintenance shops were built in the path of a potential steam generator pipe failure. As a result, the shops were removed. In addition, some maintenance shops were relocated from miscellaneous site buildings due to building obsolescence or increased security restrictions. These actions have resulted in some work groups having inadequate office and lab facilities.

4) Code Compliance Issues: Some of the relocated maintenance shops and offices do not meet the National Building Code or the American Society of Heating, Refrigeration and Air Conditioning Engineers standard. These areas include the maintenance and testing equipment labs, the valve maintenance shop, the relief valve shop, the seal lapping shop, and some maintenance supervisors' offices. As an example, the maintenance and testing equipment labs do not have adequate humidity and temperature control, making them unavailable for certain critical calibration activities approximately 30% of the time.

5) Emerging Functional Requirements: With a greater focus on supervision and employee safety, facilities are now inadequate for activities such as: pre-job briefing of crews; rehearsal and mockup areas for Inspection Maintenance Services and reactor maintenance staff; and, computer access, used in delivering work instructions, providing additional information and documenting work done.

Energy Probe Interrogatory #2

Ref: Ex. D2-T1-S2 page 9

Issue Number: 3.5
Issue: Is the additional capital spending (beyond the levels being recovered under section 6(2)4)) appropriate?

Interrogatory

Page 8 of Schedule 2 is a project summary for Darlington Chiller Replacement to Reduce Chlorofluorocarbon Emissions. In the project description section of the summary the following statement appears:

> "Replace the following chillers which cannot be converted to non-ozone depleting refrigerants".

Please explain why the chillers cannot be converted to non ozone depleting refrigerants.

Response

Since non-ozone depleting refrigerants are less efficient than the R-11 refrigerant currently in use, conversion of existing chillers to a new refrigerant would require the number of chiller units to be increased to provide the same cooling capacity. A review of the age, type and component condition of existing chillers and the space available for additional chillers confirmed that full-scale chiller replacement would be the financially preferable alternative.

Energy Probe Interrogatory #3

Ref: Ex. D1-T1-S2, Attachment A, Appendix C

Issue Number: 3.3
Issue: If the costs and financial commitments are not within project budgets approved by the board of directors of OPG, are the costs and financial commitments prudent?

Interrogatory

This document sets out the Project Risk Profile for the Niagara Tunnel Project. The first risk category on Page 1 of Appendix C relates to unexpectedly adverse subsurface conditions that could materially affect the cost of the tunnel.

a) Please explain what measures will be used to evaluate whether or not subsurface conditions are sufficiently different from those identified in testing to warrant paying the contractor for extra work claims.

b) How will OPG determine whether slower tunnel boring progress is a result of more adverse subsurface conditions than expected or a result of a less capable tunnel boring machine than expected?

c) What is the potential cost overrun if subsurface conditions are more adverse than expected?

d) How will OPG recover any cost overruns that might occur on this project?

Response

a) The Design Build Agreement between OPG and its contractor for construction of the Niagara Tunnel incorporates geotechnical criteria for the determination of Differing Subsurface Conditions (DSC), which are based on site specific geotechnical investigations and the contractor's proposed design, means and methods of construction. Any claim for compensation (cost and/or schedule) due to DSC would be progressively advanced through OPG's Owner's Representative, a Dispute Review Board (an alternative dispute resolution process involving a panel of three independent experts) and ultimately, if necessary, to binding arbitration. Based on the merit and materiality of a DSC Claim relative to the established geotechnical baseline, OPG and the contractor could negotiate a settlement at any stage in this dispute resolution process.

b) See Response a). In addition, OPG's Owner's Representative is mapping the geology as tunnelling progresses, to document actual subsurface conditions encountered for comparison with the contractual baseline geotechnical conditions.

Witness Panel: Hydroelectric Core

c) Currently, OPG believes that OPG's project cost will be within the approved budget of $985M, which includes a contingency to cover risks associated with possible DSC. This is based in part on the assumption that consistent tunnelling progress will be achieved after the tunnel boring machine advances sufficiently beyond the St. David's Gorge (See Ex. D1-T1-S1, page 3, lines 10-21).

d) As noted in a) above, OPG has a Design Build Agreement with its contractor for the construction of the Niagara Tunnel. OPG has contractual rights under that Agreement and will pursue those rights as prescribed. Beyond these contractual rights, section 6 of O. Reg. 53/05 provides that any cost above the project budget approved by OPG's Board of Directors would be subject to a prudence review by the OEB. Assuming such costs were deemed to be prudently incurred, OPG would recover them in future payment amounts.

Energy Probe Interrogatory #4

Ref: Ex. D1-T1-S2, Attachment A, Appendix C

Issue Number: 3.3
Issue: If the costs and financial commitments are not within project budgets approved by the board of directors of OPG, are the costs and financial commitments prudent?

Interrogatory

The first risk category on Page 4 of Appendix C relates to design performance of the tunnel. In case the flow capacity is not met when the tunnel is completed, the contractor faces liquidated damages but these appear to be related only to the completion testing. What guarantees or compensation does OPG have recourse to should the flow capacity deteriorate over time as a result of swelling of the Queenston shale or for other conditions related to construction quality?

Response

This risk is being mitigated through conservative, mandatory engineering specifications for aspects of the tunnel design related to swelling rock. The selected contractor is installing an impermeable double membrane surrounding the permanent concrete tunnel lining that will prevent swelling of the Queenston shale and prevent overstressing of the tunnel lining.

This type of damage is not expected to occur due to the design and construction measures that have been employed. In the unlikely event that this kind of damage did occur, it would take decades to develop. For this reason, penalties, warranties or holdbacks are impractical within the contract.

Energy Probe Research Foundation #5

Ref: Ex. F3-T2-S1, pages 2-3

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

Pages 2 and 3 of Schedule 1 discuss depreciation expense. Beginning at line 31 of Page 2 and continuing on line 1 of Page 3 the following statement appears:

> "The service life of an asset class is limited by the service life of the station(s) to which it relates."

Does this mean that new capital expenditures for nuclear stations such as those listed in the project summaries in Exhibit D2 will have service lives for the purposes of depreciation that coincide with the remaining service life of the generating units with which they are associated? If no, please explain how the undepreciated asset value of these capital additions will be accounted for if the nuclear units to which they apply are retired before the end of the additions' service lives.

Response

New capital expenditures for nuclear stations such as those listed in the project summaries in Exhibit D2 will have service lives that do not exceed the remaining service lives of the nuclear generating stations with which they are associated.

Energy Probe Interrogatory #6

Ref: Ex. H1-T1-S1 page 4

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Page 4 of 10 of Schedule 1 discusses decommissioning of nuclear generating units. The following statement appears at line 12:

> "The facility is then stored and monitored for 30 years to allow the residual radioactivity to decay. This will be followed by station dismantling and site restoration over a ten-year period."

Are the costs of maintaining and monitoring retired nuclear units over the 30 year period included in the decommissioning fund referred to on line 16 of Page 5 of the Schedule? If yes, what is the cost estimate for maintaining and monitoring each of the Pickering, Darlington and Bruce stations during the stored period? If no, please explain how the costs of maintaining and monitoring retired nuclear units will be recovered.

Response

Yes the cost of maintaining and monitoring retired nuclear units over the 30 year period are included in the decommissioning estimates and paid for from the decommissioning fund. As noted in Ex H1-T1-S1, these estimates were prepared by US based consultant TLG Services.

The total safe storage costs included in the cost estimates for each generating station over the 30 year period are as follows (in 2005 constant $):

Pickering A	$304,274,000
Pickering B	$271,730,000
Darlington	$334,649,000
Bruce A	$330,566,000
Bruce B	$323,034,000

Energy Probe Interrogatory #7

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

On Page 3 of Schedule 1 which discusses staffing requirements and recruitment, the following statement appears at line 17:

> "In order to support the diverse mix of generation capabilities within OPG, staff must be highly skilled, and must possess a wider array of skills than employees in many other utilities across the province or country."

This statement seems to suggest that OPG employees need to have a wider array of skills than in other utilities because of OPG's diverse mix of generation, as opposed to OPG requiring a broader array of skilled employees than other utilities because of its diverse mix of generation. Please explain which interpretation was intended by the statement. If the former, please explain why it is necessary to have individual employees trained in the diverse range of generation technologies used by OPG if they only work in one technology. If the latter, please confirm that individual OPG employees are no more or less qualified than comparable employees in other generation companies.

Response

Both interpretations of the statement cited in the interrogatory are correct. As discussed in L-6-011, OPG has unique and complex operations within each of its nuclear and regulated hydroelectric business segments as compared to many other utilities. This requires OPG to have a higher standard when recruiting employees into a number of positions, particularly in the nuclear business. Therefore, the first interpretation of the statement is correct.

While each employee is hired into a specific line of business, having employees who have broad transferable skill sets provides OPG with the flexibility to resource appropriately across the different generation technologies, depending on changing business needs and external factors. Hence, having employees who are able to work in more than one generating technology assists OPG in meeting long-term staffing needs. Movement of employees at OPG across Nuclear, Hydro and Fossil business units is not uncommon and is facilitated by collective agreements. Staff in corporate functions need to have a broader skills set because many of them address matters related to multiple generation types. Therefore, the second interpretation of the statement is also correct.

Energy Probe Interrogatory #8

Ref: F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

On Page 3 at line 21 of Schedule1 the following statement appears:

> "For the majority of these, two or more years of community college or a university degree are required, and this education ranges from skilled technician or technologist training, to advanced university degrees in fields such as engineering and finance. These highly skilled staff are in high demand across the country, and OPG must compete for these employees with Bruce Power and other private generators and energy service organizations as well as the general marketplace."

On Page 5 at line 11 the following statement appears:

> "The nature of the work performed at OPG means that many positions cannot be filled from normal external sources. The demand for highly-skilled and industry-specific trades and engineering knowledge requires OPG to recruit carefully and train extensively."

These statements appear to be contradictory in that the first one suggests that OPG relies on community colleges and universities to provide its requirements for skilled staff while the second one implies that its skills requirements are so specific that it must train its own staff.

a) Please provide details of the positions that cannot be filled from normal external sources referred to in the excerpt from Page 5.

b) Please describe the "industry-specific trades" referred to in the excerpt from Page 5 along with the number of each such trade that is employed by OPG expressed as a percentage of overall staffing levels.

c) Please describe the training programs referred to in the excerpt on Page 5 including details by employee group on how long it takes for a newly hired employee to become fully qualified to perform his/her job function.

Response

To clarify, OPG relies on community colleges and universities across Canada as recruitment sources to fill entry level positions or trainee apprenticeship roles. These positions are typically trainee positions or roles from which staff would grow into journey person status over time through experience and internal training. However, recruiting experienced hires from external sources is significantly more difficult.

a) The following positions are difficult to fill from external sources based on OPG's past experience:

- Senior engineering roles specific to electricity generation
- Project management roles specific to electricity generation development
- Roles that have specific to nuclear supply chain and procurement responsibilities
- Specialized roles specific to plant operations, such as Crane Operators, Protection and Control Technicians and Mechanical Maintainers

b) The following table provides some key examples of industry-specific roles expressed as a percentage of overall staffing levels at OPG based on 2006 year-end data:

Role	% of OPG's Regular Staff
Operators and Authorized Staff (Nuclear Operators, Authorized Nuclear Operators, Control Room Shift Supervisors and Managers, Fossil and Hydro Operators, including trainees)	15%
Maintainers (Control and Mechanical Maintainers / Technicians, including apprentices)	20%
Specialized Technicians (Inspection and Maintenance Technicians, Radiation Technicians)	5%
TOTAL	**40%**

c) The table below summarizes training programs provided by OPG for industry-specific trades:

Role	General time frame required to become fully qualified and summary of training
Mechanical Maintainer	**48 months:** ▪ ***In-class training***: covers plant fundamentals and safety ▪ ***On-the-job training***: practical hands-on field work ▪ ***Crew assignments***: trainees are streamed into crews responsible for specific sub-tasks
Control Technician	**61 months:** ▪ ***In-class training***: covers science fundamentals, safety and non trade specific instruction ▪ ***On-the-job training***: practical hands-on field work in a dual-trades role. All technicians are required to specialize in more than one area. Each trainee is paired with a seasoned professional for this practicum. ▪ ***Crew assignments***: trainees are streamed into crews responsible for specific sub-tasks
Nuclear Operator	**66 months:** ▪ ***In-class training***: includes simulations and computer-based modules ▪ ***Shift training***: applied practicum under the guidance of an experienced Nuclear Operator
Inspection and Maintenance Technician	**48 months:** ▪ ***In-class Training:*** covers materials and processes, codes and standards, and practical applications ▪ ***Examinations****:* written and practical examinations certified by Natural Resources Canada ▪ ***On-the-job training***: practical hands-on field work running in parallel with the examinations, as 525 hours of hands-on experience is required prior to certification ▪ ***Crew assignments:*** trainees are mentored under the guidance of an experienced Inspection & Maintenance Technician
Radiation Technician	**30 months:** ▪ ***In-class training*****:** covers general employee training, Radiation Protection (RP) fundamentals and practices, station systems, and safety ▪ ***On-the-job training:*** practical hands-on orientation and mentored field work ▪ ***Outage crew assignments***: trainees are assigned to outage RP support crews (first at the intermediate qualification level and then at full qualification level)

Energy Probe Interrogatory #9

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Chart 3 on Page 8 of Schedule 1 shows average compensation levels for employee groups within the Nuclear, Regulated Hydro and Corporate Support functions.

a) Please explain why the base salaries for regular employees in the Regulated Hydro function are uniformly higher than those in the Nuclear function.

b) Please explain why overtime in the Nuclear function is so much higher than overtime in the Regulated Hydro function.

c) Please explain how much of the lower base salary in the non regular employee groups is attributable to the temporary nature of the work and how much is attributable to differences in hourly rates.

d) Please elaborate on the "Peak" periods referenced in footnote 5 of the table including an explanation of the need for temporary staff during those periods.

e) Please explain why the Benefits category of compensation for Regular employees in the Management Group in the Regulated Hydro function is significantly higher than those in the Nuclear and Corporate functions.

f) Please provide a comparable table showing the same compensation information for the non regulated functions of the business.

Response

a) The difference between average base salaries in nuclear and hydroelectric is due primarily to differences in average employee seniority across the two businesses. The employees in the regulated hydroelectric business generally have higher seniority than those in the nuclear business.

b) The nuclear business uses overtime during both planned and forced outages for peak labour needs, as discussed in part d) below. As well as augmenting regular staff with non-regular staff, it is also more cost effective and flexible to pay existing resources overtime, as needed, during an outage than to add permanent staffing. While the regulated hydroelectric business also experiences outages, these typically

do not require a significant use of overtime. This is due to the fact that hydroelectric outages are typically undertaken during periods of low water availability when the full capacity of the station may not be required and the fact that hydroelectric units generally have a smaller impact on the electricity system because of their significantly lower unit capacities as compared to nuclear units.

c) The lower base salary in the non-regular employee groups is attributable primarily to the shorter periods of time worked during the year. Specific hourly rate differences cannot be identified because they are dependent on the seniority of the employees in question.

d) Peak periods generally refer to the periods during station outages where the majority of the outage scope is scheduled to be performed in such a short period that regular staff, even when working overtime, require the support of additional tradespeople such as mechanics, millwrights and labourers from various union hiring halls.

e) The computation of the average benefits cost in the regulated hydroelectric function contained an error. The corrected values for the average amounts in the benefits category of compensation for regular employees in the PWU, Society and Management groups in regulated hydroelectric in Chart 3, Ex. F3-T4-S1, page 8 are $4.6K, $4.7K and $7.3K, respectively. Therefore, the variance cited in the interrogatory does not apply.

f) Compensation information for the unregulated businesses within OPG is not relevant to the determination of payment amounts for the regulated facilities and therefore is not provided.

Energy Probe Interrogatory #10

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Page 12 of Schedule 1 discusses Management Group compensation. The following statement appears at line 8:

> "In 2005, OPG continued with the freeze in salary structure and the salaries of Senior Vice Presidents and above."

a) How many employees are covered by the category of Senior Vice President and above?

b) How long does OPG expect it to take before executive salaries return to the target level?

Response

a) As of December 31, 2007 there were 12 people in the category of Senior Vice President and above at OPG.

b) The executive salaries were frozen in 2005 as a cost-cutting measure, not because they were off target. In 2006, OPG allowed for performance based salary changes for senior executives. In late 2007, salaries of senior executives at OPG were compared to the public and private comparator groups at the 50th percentile level in accordance with OPG's executive compensation review process described in Ex. F3-T4-S1 (pages 12 - 13) and were found to be within an acceptable market range.

Energy Probe Interrogatory #11

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Starting at line 27 on Page 12 of Schedule 1 discussing executive compensation, the following statement appears:

"OPG's philosophy is to position OPG's Management Group compensation at the 75th percentile against other utilities and around the median or 50th percentile of comparable non utility sector companies. The reason that the 75th percentile in the utility market is used is due to OPG having unique and diverse assets that are not found in other utilities in Canada."

a) What are the "unique assets" that sets OPG apart from other utilities?

b) Does OPG have a lower target compensation level for management working in the "non unique" asset functions?

c) Please explain why "having unique and diverse assets" is a justification for targeting executive compensation at a higher level than would otherwise be the case.

d) How does the 75th percentile target compare to comparable targets for the management group in the former Ontario Hydro?

Response

OPG notes that the interrogatory references the original pre-filed evidence dated November 30, 2007. The updated pre-filed evidence dated March 14, 2008 indicates on lines 3 - 5, page 13, Ex F3-T4-S1 that OPG has reviewed its philosophy in late 2007 and plans to conduct a comparison of executive compensation using the 50th percentile for utility markets going forward.

a) The "unique assets" and related factors that set OPG apart from other utilities include OPG's large number of nuclear stations, which contain the first large-scale commercial CANDU reactor units ever built. As a result, many of the technological issues faced by OPG are being addressed for the first time in the nuclear industry. As well, OPG's prescribed hydroelectric assets are governed by international agreements and treaties which place specific requirements on the operation of the assets. These assets are also among some of the oldest hydroelectric generating

assets in Canada and their aging is causing an increased need for maintenance and refurbishment. Additional details on these unique aspects of OPG's nuclear and regulated hydroelectric assets are described below in part c and also in Ex. A1-T4-S3 and Ex. A1-T4-S2, respectively.

b) OPG does not have a lower target compensation level for management working in the "non-unique" asset functions.

c) "Having unique and diverse assets" requires OPG to maintain a compensation approach that is designed to ensure that it attracts and retains key talent in a highly specialized and technical industry that is becoming increasingly competitive in the labour market. Over 50 percent of OPG's business is in nuclear generation, which is a uniquely high percentage among other regulated utilities in Canada. Overall, OPG's nuclear fleet is unique among other regulated utilities in Canada with nuclear operations. This is due to the fact that the range of nuclear design types operated by OPG reflects the evolution of the CANDU technology from its inception and ranges over a period in excess of three decades. No other nuclear operator in Canada requires the same breadth of design knowledge and expertise and the same extent of ability to manage the operating conditions resulting from the size and nature of OPG's nuclear fleet.

OPG's hydroelectric assets such as the generating stations at Niagara Falls and on the St. Lawrence River also require additional expertise. International agreements under which these regulated hydroelectric assets operate result in more complicated operating requirements in areas such as water flow management. Refurbishment and maintenance strategies for some of the prescribed hydroelectric assets are also more complex than those for other hydroelectric assets. Hydroelectric Management must also operate regulated hydroelectric assets to ensure that the interests of the many community and government stakeholders with respect to these watersheds and potential impacts on the environment are balanced with the objective of optimizing electricity generation.

Management staff in corporate functions also require more extensive expertise as they face a wider variety of issues resulting from the diverse mix of generating technologies operated by OPG. For instance, corporate staff must possess the necessary understanding of the specifics of each generation type in order to manage various types of risks. They must also engage in labour relations with a large number of unions, ensure compliance with a wide variety of legislative, environmental and regulatory requirements, and manage a real estate asset portfolio that is spread across a broad range of geographic locations.

d) Information regarding the compensation targets for the management group employees in the former Ontario Hydro is not relevant to the determination of payment amounts for OPG's regulated facilities, as OPG is a separate and distinct

entity from the former Ontario Hydro, which ceased to exist on March 31, 1999. Therefore, this information is not provided.

Energy Probe Interrogatory #12

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Starting at line 1 on Page 17 of Schedule 1, the following statement appears:

> "Management Group employees who are required to work shifts are paid a leadership allowance. This allowance is in lieu of provisions such as shift premiums and on-call payments which are afforded to represented employees who work shifts. The leadership allowance provides for up to 30 percent - 40 percent of base salary, of which 10 percent is pensionable".

a) Does the shift premium and on call allowances for unionized staff amount to 30% - 40% of their base annual earnings? If yes, please explain why this should be so high. If no, please explain why Management Group employees should receive a higher percentage allowance for on call and shift premium.

b) Are shift premiums and on call allowances for Management Group employees included in the analysis to arrive at the 75th percentile compensation level compared to other utilities referred to in Interrogatory # 11 above?

Response

a) No, the shift premium and on call allowance for unionized staff do not amount to 30 percent - 40 percent of their base earnings. The Management Group allowance is higher in order to recognize the additional responsibilities of Management Group employees and the fact that they are not paid for overtime, whereas unionized staff is paid for overtime. This approach allows OPG to attract internal candidates to management positions from qualified unionized staff.

b) No. Information on these types of payments is generally not collected in benchmarking studies because of the significant variability in their design and application.

Energy Probe Interrogatory #13

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Page 17 of Schedule 1 discusses payments made to specified staff such as nuclear control room operators and shift supervisors. Starting at line 10 the following statement appears:

> "The staff licensing process is set out by the Canadian Nuclear Safety Commission and represents a challenging and time-consuming task. Not every employee is prepared to devote personal time and effort necessary to obtain and maintain a license."

a) Please explain why bonuses are necessary for licensed employees to maintain their licenses if that is a condition of employment for these positions?

b) Why does OPG think it needs to offer these bonuses to "attract and retain staff" as noted on line 8 if its assets are "unique" and therefore the only places that require nuclear operators?

c) Why are these payments pensionable?

d) What percentage of authorized employees required to have and maintain a license from the CNSC allow those licenses to lapse?

e) What happens to those employees who do not obtain and/or maintain a license?

f) Does OPG provide similar incentives to other professionals such as engineers, lawyers, accountants etc. who must also be licensed by their respective regulatory bodies?

Response

a) License retention bonuses are common in the nuclear industry. OPG provides these bonuses in order to attract and retain qualified candidates for positions where it is necessary to undertake extensive training and testing. While being licensed is a requirement for the positions at which this incentive is aimed, it is not a general condition of employment within OPG's nuclear operations. This is the case because OPG's nuclear operations are large and diverse and allow multiple opportunities for staff to

remain employed in unlicensed positions. Therefore, attraction and retention of candidates for licensed positions is not dependent on OPG's nuclear assets being "unique" but rather on OPG's ability to persuade nuclear employees who possess the required skills for licensed positions to work in licensed positions instead of in unlicensed positions.

b) While each nuclear facility has licensing requirement some of the skills and training would make a candidate more attractive to other nuclear operators. Please refer to the response to part a).

c) License retention bonuses are pensionable based on the terms of negotiated collective agreements.

d) Approximately 1 percent of authorized employees who require a license allowed their licenses to lapse each year over the period from 2005 to 2007. (A "lapsed license" is defined as a license given up for reasons other than retirement or job re-assignment/promotion to an unlicensed role.)

e) Specific provisions have been negotiated in the collective agreements regarding consequences for employees who do not obtain or renew their licenses. Generally, these employees continue to work in positions at OPG that do not require a license.

f) Authorized Shift Managers and Authorization Training Supervisors in the nuclear business also receive license retention bonuses, but no other professionals at OPG receive similar incentives.

Energy Probe Interrogatory #14

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Page 17 of Schedule 1 also discusses Pensions and Other Post Employment Benefits (OPEBs).

a) Are OPEBs provided to all OPG pensioners on a cost free basis? If not, please explain how much is paid by the pensioner and how much by OPG.

b) Are OPEBs to pensioners time limited? If yes, at what age do the benefits stop? If the benefits are life time, how does this practice compare with retirement benefits provided by other comparable utilities and private sector comparators used by OPG to benchmark its compensation policies?

Response

a) Post employment benefits are provided to eligible pensioners at no cost to them.

b) Post employment benefits for eligible pensioners are not time limited with the exception of group life insurance, which drops by 50 percent of base pay immediately upon retirement and to 25 percent of base pay after 10 years following retirement. OPG participates in a Watson Wyatt benchmarking survey of pension and benefits. The 2006 report on the survey indicates that the majority of comparators in the Energy, Resources and Utilities sector do provide post-retirement benefits and that most of those who do provide them do not require contributions. While the question of the time limitations of benefits was not addressed by the survey, it is OPG's understanding, based on knowledge of other pension and benefit plans, that its practices in this area are similar to those of other comparable companies.

Energy Probe Interrogatory #15

Ref: Ex. D2-T1-S2 page 7

Issue Number: 6.4
Issue: Are there revenues and related costs other than those included in the application, that OPG earns or incurs from the prescribed assets that should be included in the application?

Interrogatory

Page 7 of Schedule 2 is a project summary for the Darlington D2O Storage Facility. In the Project Need section of the summary the following statement appears:

> "Allow OPG to pursue new business opportunities associated with detritiation services".

Please explain in more detail what the "new business opportunities" consist of. If these are non regulated business opportunities, how has the cost of the project been allocated to reflect that fact?

Response

As discussed in Ex. G2-T1-S1, OPG 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.

OPG's ability to grow the tritium removal business is currently limited by its ability to store heavy water (D20). A new D20 storage facility will, as described in the project summary, allow OPG to expand its sales of tritium removal services.

OPG is proposing in this application that all third party revenues and related costs associated with its nuclear non-energy business including tritium removal services be recorded as an offset to the determination of the regulated payments amounts.

Energy Probe Interrogatory #16

Ref: Ex. B1-T1-S 1, page 1 of 8

Issue Number: 1.1
Issue: Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

Interrogatory

The Prefiled Evidence indicates that the Prescribed Facilities be held, and the associated business activities will be conducted, within OPG. This appears to create complications of separating those facilities and their financial activities from the other parts of OPG.

Does the commingling give rise to allocations and reconciliations of financial information that affect the determination of the rate base and revenue requirements of the Prescribed Facilities?

Response

OPG has significant regulated and unregulated operations within a single corporate entity, and certain allocations are required to determine the revenue requirement for the prescribed facilities. OPG is of the view that the methodology for allocating these costs is reasonable and results in an appropriate determination of the revenue requirement for the prescribed facilities. This view is supported by the conclusions of the R.J. Rudden cost allocation review as discussed at Ex. F3-T1-S1 section 4.

With respect to rate base, the most significant component is in-service fixed assets. All of the in-service fixed assets in the rate base are associated with specific nuclear or hydroelectric facilities or are shared by the regulated nuclear stations. Capital expenditures by corporate groups are discussed in the response to interrogatory L-6-017.

The working capital component of rate base consists of fuel inventory and materials and supplies, which relate almost entirely to nuclear operations, as well as cash working capital. The only component of OPG's rate base where allocation is required is the cash working capital component. Cash working capital represents a very small part of rate base (<0.5%); and therefore is a relatively minor component of the total revenue requirement.

Since April 1, 2005, OPG has taken several steps to separate the operational and financial reporting for its regulated and unregulated operations as discussed OPG's response to interrogatory L-6-20. The allocations of corporate and centrally-held costs

impacts approximately 10% to 15% of the revenue requirement. OPG's allocation methodology is consistent with best practices, as discussed in Ex. F4-T1-S1.

Energy Probe Interrogatory #17

Ref: Ex. D3-T 1-S1, Table 1

Issue Number: 1.1
Issue: Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

Interrogatory

According to the Prefiled Evidence, capital expenditures by certain of OPG's Corporate Groups are to be made on assets related to (or that impact on) the Prescribed Facilities.

Are any of these assets included in the rate base? If so, please identify the total relevant capital expenditure, as shown in Table 1, on those assets for the test period.

Response

Most of OPG's fixed assets are directly associated with specific business units once they are declared in-service and are therefore included in rate base for that business unit. Certain assets of OPG's corporate groups are used by more than one business unit and they are therefore held centrally. The assets held centrally are not included in rate base. Instead, business units (including nuclear and regulated hydroelectric) are charged a service fee for the use of these assets. Asset service fees charged to the nuclear and regulated hydroelectric business units are included in the revenue requirement as expense items. Please refer to Ex. F3-T3-S1 for details on asset service fees.

Capital expenditures by corporate groups can result in assets that are directly associated with a business unit once declared in-service (e.g., an information technology project undertaken by the CIO group solely for the benefit of the nuclear business unit), and therefore become part of the rate base for that business unit.

For the historical years 2005 through 2007, approximately $19M of the corporate groups' capital expenditures presented in Table 1, Ex. D3-T1-S1 were placed in-service in the nuclear and regulated hydroelectric rate base. These expenditures were undertaken on behalf of the regulated operations by corporate groups such as the CIO.

Upon further review of the project details and the forecast in-service additions for the test period, OPG has now determined that $22M of the corporate group's capital expenditures in 2008 - 2009 period are solely associated with nuclear and $1.9M are solely associated with regulated hydroelectric.

The impact of the in-service addition of these projects was, erroneously, not included in the test period rate base. Nor was it factored into the asset user fees charged to the regulated businesses.

The impact of this omission on the test period revenue requirement is $4.7M as shown below. OPG intends to update its evidence prior to the hearing to seek recovery of this amount.

$ millions	Regulated Hydroelectric			Nuclear		
	2008	2009	Test Period	2008	2009	Test Period
Capital	1.6	0.3	1.9	12.4	9.6	22.0
In-Service Additions	0.8	1.0	1.8	6.2	11.0	17.2
Increase in Avg Rate Base *	0.6	1.1	0.9	4.3	10.6	7.9
Increase in Rev Requirement	0.1	0.4	0.5	0.9	3.3	4.2

**increase in Avg Rate base for 2008 is for the period April 1 to December 31.*

Energy Probe Interrogatory #18

Ref: Ex. B3-T1-S1, Table 2

Issue Number: 1.1
Issue: Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

Interrogatory

The Prefiled Evidence presents information on the working capital component of the rate base in 2008 on a calendar-year basis rather than on a test-period basis.

What is the level of working capital (cash, fuel, materials and supplies) in the rate base for nuclear as of the beginning of the Test Period March 1, 2008?

Response

Non-cash working capital is comprised of supplies and material inventory and nuclear fuel. Materials and inventory do not exhibit any seasonal purchase patterns. This working capital item is not forecast on a monthly or even a quarterly basis but rather an annual need is forecast and assumed to occur uniformly throughout the period. As a result, the rate base value remains the same throughout the year.

Nuclear fuel is purchased to minimize cost in both the short- and long-run while ensuring availability of supply. There is limited seasonality to the purchase patterns for nuclear fuel as it supports base load generation and therefore a mid-year average approach is preferred for its simplicity. As with materials and supplies, the rate base amount remains the same throughout the year.

As OPG's regulated assets are predominantly used to provide base load energy at a regulated price, the vast majority of OPG's costs are fixed as discussed in L-2-1, and the cash working capital amount is a relatively small component of OPG's forecast working capital requirements, the amount of working capital needed would not be expected to change materially from January 1 to April 1.

No adjustment was made to the working capital components of rate base as a result of removing activity from January 1, 2008 to March 31, 2008 as shown in Ex. K1-T1-S1. The level of nuclear working capital including cash working capital required for the 2008 portion of the Test Period beginning April 1, 2008 (not March 1, 2008) is $721.4M. As shown in Ex. B3-T6-S1 this is composed of $281.1M Fuel Inventory, $424.4M Materials & Supplies and $16M Cash Working Capital.

Energy Probe Interrogatory #19

Ref: Ex. B3-T1-S1, page 1 of 8

Issue Number: 1.1
Issue: Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

Interrogatory

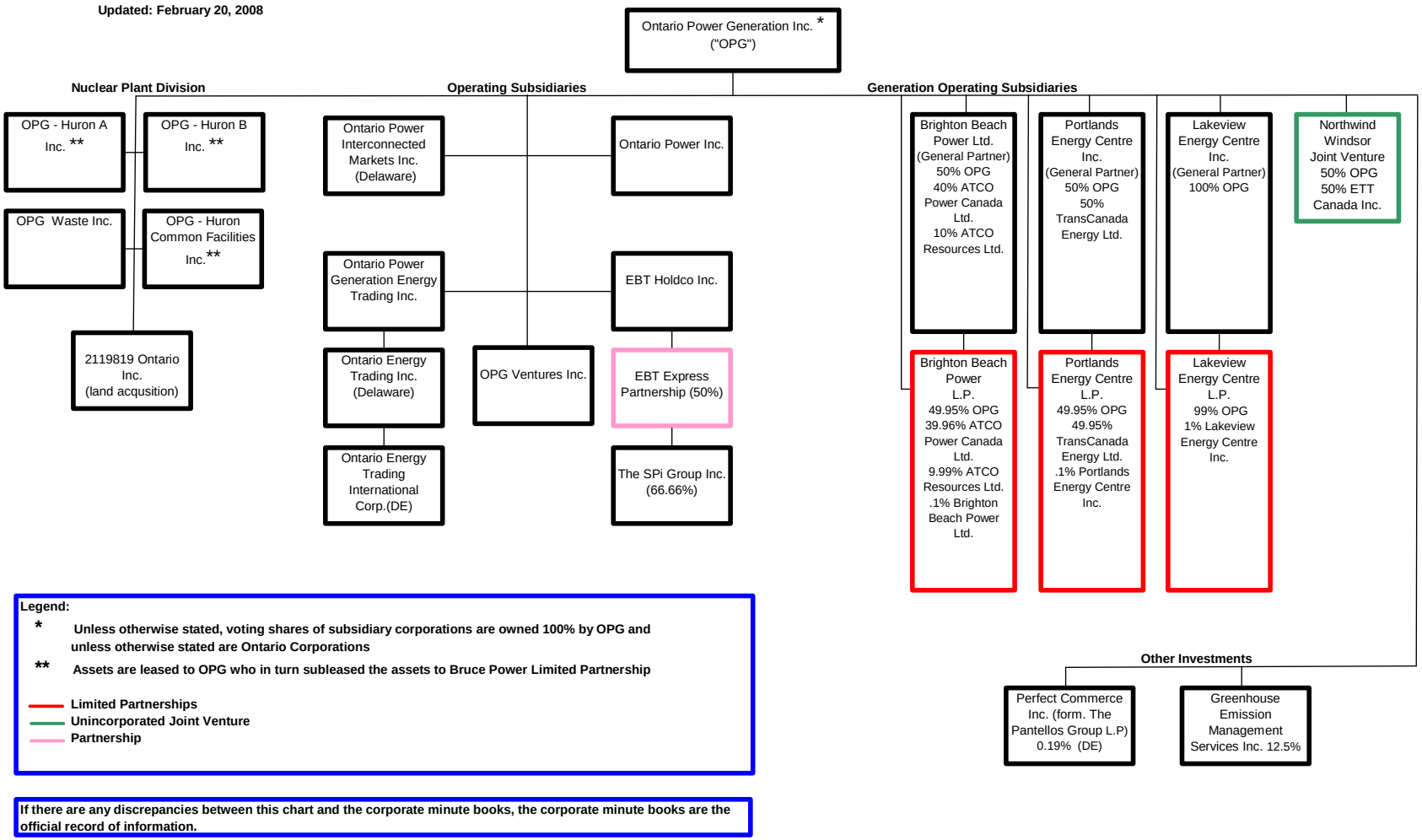
The Prefiled Evidence indicates that the Prescribed Facilities be held, and the associated business activities will be conducted, within OPG. This appears to create complications of separating those facilities and their financial activities from the other parts of OPG.

a) Does OPG currently operate or invest in businesses through subsidiaries? If so, please identify those businesses and investments.

b) Suppose, in order to maintain the approved debt/equity ratio for the Prescribed Facilities, OPG paid a dividend. Apart from the reporting on OPG's financial statement, how would this dividend affect the activities and financial condition of the Prescribed Facilities?

Response

a) The chart below highlights OPG's investments in businesses. Significant joint ventures include Brighton Beach and Portlands Energy Centre, which are 50 percent owned by OPG.


Updated: February 20, 2008
Ontario Power Generation Inc. *
("OPG")
Nuclear Plant Division
Operating Subsidiaries
Generation Operating Subsidiaries
OPG - Huron A Inc. **
OPG - Huron B Inc. **
OPG Waste Inc.
OPG - Huron Common Facilities Inc.**
2119819 Ontario Inc. (land acqusition)
Ontario Power Interconnected Markets Inc. (Delaware)
Ontario Power Inc.
Ontario Power Generation Energy Trading Inc.
EBT Holdco Inc.
Ontario Energy Trading Inc. (Delaware)
OPG Ventures Inc.
EBT Express Partnership (50%)
Ontario Energy Trading International Corp.(DE)
The SPi Group Inc. (66.66%)
Brighton Beach Power Ltd. (General Partner) 50% OPG 40% ATCO Power Canada Ltd. 10% ATCO Resources Ltd.
Portlands Energy Centre Inc. (General Partner) 50% OPG 50% TransCanada Energy Ltd.
Lakeview Energy Centre Inc. (General Partner) 100% OPG
Northwind Windsor Joint Venture 50% OPG 50% ETT Canada Inc.
Brighton Beach Power L.P. 49.95% OPG 39.96% ATCO Power Canada Ltd. 9.99% ATCO Resources Ltd. .1% Brighton Beach Power Ltd.
Portlands Energy Centre L.P. 49.95% OPG 49.95% TransCanada Energy Ltd. .1% Portlands Energy Centre Inc.
Lakeview Energy Centre L.P. 99% OPG 1% Lakeview Energy Centre Inc.
Other Investments
Perfect Commerce Inc. (form. The Pantellos Group L.P) 0.19% (DE)
Greenhouse Emission Management Services Inc. 12.5%
Legend:
* Unless otherwise stated, voting shares of subsidiary corporations are owned 100% by OPG and unless otherwise stated are Ontario Corporations
** Assets are leased to OPG who in turn subleased the assets to Bruce Power Limited Partnership
Limited Partnerships
Unincorporated Joint Venture
Partnership
If there are any discrepancies between this chart and the corporate minute books, the corporate minute books are the official record of information.

1

b) OPG's proposed revenue requirement is based on a deemed capital structure; therefore the debt equity ratio for the prescribed facilities would not change as a result of paying a dividend. Payment of the dividend to "maintain the approved debt/equity ratio" would result in the replacement of the "other long-term debt provision in OPG's proposed capital structure with new long-term debt. The cost of that debt would be forecast to be the same; therefore the activities and financial condition of the prescribed facilities would be unaffected.

Energy Probe Interrogatory #20

Ref: Ex. C2-T1-S1, page 122 of 261

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

The expert opinion on capital structure and fair return on equity states that it is important that the proposed deemed capital structure avoids potential cross-subsidization and proposes a formula at footnote 118.

a) Does the formula indicate the capital structure that results in no cross-subsidization? If not, how does the formula contribute to avoiding cross-subsidization?

b) What other measures, if any, in addition to deeming a capital structure for the regulated activity would be required avoid cross-subsidization with non-regulated activities within the same corporate entity? For example, would separate financial accounts be necessary?

Response

a) No. The formula provided in footnote 118 was to provide a simple illustration of how one could estimate the implied capital structure of the unregulated operations cannot be estimated. There is no mechanistic capital structure formula for determining if there is cross-subsidization. The implied capital structure of the unregulated operations would have to be evaluated in the context of the business risks faced by those operations.

b) Since April 1, 2005, OPG has taken several steps to separate the operational and financial reporting on its regulated and unregulated operations. This includes dedication of certain support groups to specific business units, separate tracking and reporting of costs and assets, preparing audited financial results for the regulated and unregulated business segments, and separating reporting relationships within the Hydroelectric business unit which has both regulated and unregulated plants. OPG has also adopted a comprehensive cost allocation methodology which was reviewed and endorsed by independent cost allocation experts, R.J. Rudden. R.J. Rudden found that the methodology used by OPG to distribute the corporate and centrally-held costs separates the costs between regulated and unregulated business units meets best practices and is consistent

with cost allocation precedents established by the OEB. These changes were implemented in order to ensure there is no cross-subsidization. Given these steps, separate financial accounts are not necessary.

Energy Probe Interrogatory #21

Ref: Ex. C2-T1-S1, page 11 of 261

Issue Number: 2.4
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

a) Following the stand-alone principle, should the Prescribed Facilities be financed on terms and conditions appropriate to those assets and activities as established by financial markets, or should they be financed on terms and conditions at which OPG can finance if they are more favourable?

b) Is the debt associated with the Prescribed Facilities supported by any form of implicit guarantee of the Ontario Government? If so, what are the implications for the appropriate capital structure for those assets?

Response

a) In principle, they should be financed on terms and conditions that are appropriate to those assets. When OPG borrows through OEFC, the terms and conditions for long-term debt issues are established on a similar basis to those OPG would most likely be able to obtain in the public markets, other than the 10 year maximum term of the debt under the agreements with the OEFC.

b) The Province of Ontario does not implicitly guarantee any of OPG's debt obligations. Both of the debt rating agencies who currently rate OPG's long and short term debt have indicated that they afford a positive measure to the ratings that recognizes the 100 percent government ownership as well as the fact that electricity generation is an essential service required by the residents and businesses of Ontario. With respect to the implications for the capital structure, the adherence to the stand-alone principle for the purpose of establishing an appropriate capital structure is a means of ensuring that OPG is fully self-supporting, and is allowed a return on capital that meets the three criteria of a fair return based on its business and risk profile (ability to attract capital on reasonable terms and conditions, maintenance of financial integrity and opportunity to earn a return commensurate with those available to companies of similar risk).

Energy Probe Interrogatory #22

Ref: Ex. C2-T1-S1, pages 1 - 261

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

a) Does OPG or its expert rely on a forecast of the rate inflation that is reflected in the nominal expected rates of return on debt and equity for which it is seeking approval? If so, please provide details of these inflation expectations and any studies that have been relied upon.

b) Please provide copies of all financial analysts' reports and bond rating agency reports that were relied upon in establishing the recommended return on equity.

c) Please identify the Bank of Canada series numbers for T-bill rates in Schedule 1: Trends in Interest Rates and Outstanding Bond Yields (Exh.C2/T 1/S 1, p. 214).

d) Is the 12.5% fair return on equity for a benchmark Canadian utility based on the comparable earnings test (Exh.C2/T 1/S 1, p. 50) a return on the book value of equity or the market value of equity?

e) Are the returns on equity based on the equity risk premium test and on the discounted cash flow test (Exh.C2/T 1/S 1, p. 50) returns on book value of equity or the market value of equity?

f) Please indicate how the results of the comparable earnings test were used to adjust the returns obtained by the other methods to produce the recommended 10.5% equity return. (Exh.C2/T 1/S 1, p. 51)

Response

a. Ms. McShane did not explicitly rely on a forecast rate of inflation for the purpose of estimating a reasonable return on equity. The most recent consensus long-term forecasts of CPI inflation for Canada and the U.S. which are likely to be representative of investors' long-term expectations were published in Consensus Economics, *Consensus Forecasts,* October 2007. (The long-term forecasts are published twice annually, in October and April). The October 2007 consensus anticipated CPI inflation of 2.0% for Canada and 2.25% for the US from 2008-2017.

b. All documents that Ms. McShane relied on were provided in response to:

Board Staff:	L-1-2
Pollution Probe:	L-12-13; L-12-16; L-12-18; L-12-50
CCC and VECC:	L-3-13

c. The Bank of Canada series number is V39065.

d. They are based on book value.

e. They are based on market value.

f. Approximately 25% weight was given to the comparable earnings test and the remainder to the risk premium and discounted cash flow tests.

Energy Probe Interrogatory #23

Ref: Ex. D1-T1-S1, Table 1 and Ex. D2-T1-S1, Table 1

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

It appears that capital expenditures for regulated hydro and nuclear include the capital expenditures for the full 2008 rather than only the last 9 months thereof that the test period covers. In addition, it is not clear whether the capital expenditures for hydro and nuclear in the referenced exhibits include capital spending also included in OM&A

a) What is the capital expenditure for regulated hydroelectric (as shown in Exh. D1/T 1/S1, Table 1) for the 9 months of 2008 in the test period?

b) What is the capital expenditure for nuclear (as shown in Exh. D2/T 1/S1, Table 1) for the 9 months of 2008 in the test period?

c) Does the capital expenditure on regulated hydroelectric (as shown in Exh. D1/T 1/S 1,Table 1) include capital spending on hydro that is included in OM&A? If so, how much spending is included in OM&A over the test period?

d) Does the capital expenditure on nuclear (as shown in Exh. D2/T 1/S 1, Table 1) include capital spending on nuclear that is included in OM&A? If so, how much spending is included in OM&A over the test period?

e) Are the capital expenditures (as shown in Exh. D1/T 1/S 1, Table 1) for regulated hydro and (as shown in Exh. D2/T 1/S 1, Table 1) for nuclear net of any disposals of Prescribed Facilities in the test period? If not, then please provide the cash flow expected from such asset disposals.

Response

(a) The capital expenditure for hydroelectric for the nine months of 2008 in the test period is shown below in Table 1.

Witness Panel: Hydroelectric Core
Nuclear Projects

Table 1
2008 Regulated Hydroelectric Capital in the Test Period

Line No.	Prescribed Facility	2008 Plan	2008 Q2 – Q4 Plan
1	**Niagara Plant Group**	33.6	28.8
2	**Niagara Tunnel Project**	170.6	143.8
3	**Saunders GS**	4.6	2.0
4	**Total**	208.8	174.6

(b) The capital expenditure for nuclear for the nine months of 2008 in the test period is shown below in Table 2.

Table 2
2008 Regulated Nuclear Capital in the Test Period

Sponsoring Division/Category	2008 Plan	2008 Q2 to Q4 Plan
	(a)	(b)
Facility Projects (Released)		
Darlington NGS	63.5	49.4
Pickering A NGS	25.4	22.0
Pickering B NGS	15.6	11.4
Engineering & Modifications	9.0	6.2
Programs & Training	21.1	11.6
Supply Chain	2.2	1.8
Inspection & Maintenance Services	7.3	5.9
Total Facility Projects (Released)	144.0	108.3
Facility Projects to be Released	30.4	18.0
Contingency	0.0	0.0
Balancing Adjustment	(2.4)	(2.4)
Subtotal Project Capital (Portfolio)	172.0	123.9
P2/P3 Isolation Project	17.0	15.6
Pickering B Refurbishment Project	0.0	0.0
Total Project Capital	189.0	139.5

(c) Ex. D1-T1-S1, Table 1 includes only regulated hydroelectric capital expenditures as defined by OPG's capitalization policies described in Ex. A2-T2-S1, Section 4.1. When a large project has both capital and OM&A components, the OM&A component is tracked and reported separately, as in the case of the Sir Adam Beck I Generating Station unit upgrades described in Ex. D1-T1-S2. The overhaul of turbine components is identified as a separate OM&A project that is related to the upgrade. Regulated hydroelectric OM&A projects are described in Ex. F1-T3-S1. The only expensed items included with capital expenditures are removal costs described in Ex. F3-T2-S1, page 2, lines 14 - 19. Removal costs have not been separately identified for individual capital projects, and therefore the exact amount of these costs in the test period is undetermined.

(d) None of the capital spending on Nuclear projects (Ex. D2-T1-S1, Table 1) is included in any of the OM&A exhibits.

Witness Panel: Hydroelectric Core
Nuclear Projects

(e) Nuclear capital expenditures shown in Ex. D2-T1-S1, Table 1 do not include cash flows associated with asset disposals. The only asset disposal where material cash flows are anticipated in the test period is the sale of the Pickering B remote emergency power generator, which is anticipated to sell for an amount very close to its net book value of $8.8M.

Regulated hydroelectric capital expenditures shown in Ex. D1-T1-S1, Table 1 do not include cash flows associated with asset disposals. Positive cash flows associated with asset disposal are typically small amounts related to the salvage of scrap metal.

Energy Probe Interrogatory #24

Ref: Ex. K1-T1-S1, Table 1 and Table 2

Issue Number: 5.2
Issue: Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

Interrogatory

Is the "Depreciation & Amortization" expense item shown in the Summary of Revenue Requirement calculated according to generally accepted accounting principles or according to income tax laws?

Response

"Depreciation & Amortization" expense amounts shown in Ex. K1-T1-S1, Table 1 and Table 2 (Summary of Revenue Requirement) represent the sum of 1) forecast depreciation expense presented in Ex. F3-T2-S1, Table 1 and Table 3, which is determined in accordance with generally accepted accounting principles, and 2) the proposed recovery amounts of deferral and variance accounts during the test period presented in Ex. J1-T2-S1, Table 2 and Table 3 and determined in accordance with OPG's deferral and variance account recovery proposals. Income tax laws are not relevant to the determination of the "Depreciation & Amortization" expense item shown in the Ex. K1-T1-S1, Table 1 and Table 2 (Summary of Revenue Requirement).

Energy Probe Interrogatory #25

Ref: Ex. C

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

In its current deliberations on the Business Case for the Refurbishment of Pickering-B, is OPG assuming that its future compensation for Pickering-B's output will be dictated by a future O.E.B. cost-of-service hearing like this one, or by a "side deal" like those signed by O.P.A. and Bruce Power? If that assumption is based on anything, please explain.

Response

Pickering B is a regulated asset.

Energy Probe Interrogatory #26

Ref: Ex. C2-T1-S1, page 69

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

a) For each of the past five (5) years, please indicate how often (in hours/year or %) OPG's compensation for nuclear generation exceeded the IESO's market price for electricity at the time.

b) Please provide a forecast for 2008 and 2009.

Response

Compensation is assumed to mean energy output paid at regulated rate of 49.50 C$/MWh. This does not take into account non-energy charges such as debt retirement, hourly uplift, rural remote support, IESO admin charges, and OPA admin charges for energy consumed.

a) Data has been provided for the period starting on April 1, 2005 which is when the prescribed nuclear generation started to receive its regulated rate of 49.5 C$/MWh. Prior to April 1, 2005, the payments were subject to Market Power Mitigation Agreement (MPMA) rebate mechanism.

Additional historical data is provided in Ex. A1-T11-S1, Appendix C.

Period Start Date	Period End Date	Number of hours where the regulated payment amount for nuclear exceeded HOEP
1-Apr-05	31-Dec-05	2,628
1-Jan-06	31-Dec-06	5,811
1-Jan-07	31-Dec-07	5,439

b) OPG's Business Plan 2008 – 2010 forecasts the following number of hours where the current regulated rate of 49.5 C$/MWh for the prescribed nuclear assets exceeds forecast market prices.

Period Start Date	Period End Date	Forecast number of hours where the regulated payment amount for nuclear exceeds HOEP
1-Jan-08	31-Dec-08	6,072
1-Jan-09	31-Dec-09	5,959

Energy Probe Interrogatory #27

Ref: Ex. C2-T1-S1

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Regarding OPG's choice of 10.5% Return on Equity:

a) Since the evidence indicates that nuclear stations bring especially high levels of risk, why has OPG chosen to apply the same RoE to Hydroelectric and Nuclear assets? What would be the effect of assigning two separate technology-specific and risk-related RoEs to OPG's Hydroelectric and Nuclear assets?

b) Is OPG internally applying a 10.5% RoE to its Pickering-B Refurbishment Project? To Nuclear New Build? If OPG uses or supports different RoEs for these different nuclear projects and facilities, please explain why.

Response

a) See response to interrogatories L-3-2 and L-12-2.

The effect of assigning a higher ROE to one business and a lower ROE to the other would be to increase the revenue requirement for one technology and lower it for the other. However, the overall revenue requirement for the prescribed facilities would remain the same.

b) For the Pickering-B Refurbishment Project please see the response to interrogatory L-3-2 part (d).

ROE for Nuclear New Build has not yet been established.

Energy Probe Interrogatory #28

Ref: Ex. F2-T2-S1 page 8

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

OPG's evidence lists OPG's "Non-Standard [Nuclear] Fleet" as a driver of high costs.

Please explain the impact of the choice between Pickering-B Refurbishment vs. New Build on this cost driver. Is this impact being explicitly considered in the deliberations on the Pickering-B Refurbishment?

Response

OPG's evidence identifies key drivers of base OM&A. A Non-Standard Fleet is one, among many, key drivers that influence the level of base OM&A (Ex. F2-T2-S1).

A decision to proceed with the refurbishment of Pickering B, or a decision to proceed with new nuclear generation, does not change this driver of base OM&A. OPG would continue to operate a non-standard fleet in either scenario, and therefore this is not a consideration in the deliberations for Pickering B.

Energy Probe Interrogatory #29

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

a) What has been the actual historic average annual rate of Forced Production Losses (FLR) for OPG's nuclear generating units, over the years?

(i) Please present the results both including and excluding reactors that are on long-term shutdown or prematurely shut down.

(ii) Please present the results disaggregated for each reactor, for each year of operation.

(iii) Please present the average for all units in their first year of operation, all units in their second year of operation, and so on, and please include all 20 OPG units.

b) Is it OPG's position that the historical record is significantly different than the forecast rate? If so, please explain.

c) Is it OPG's position that the historical record shows a significant trend with unit age? If so, does OPG's forecast reflect the continuation of that trend? Please explain.

Response

a) OPG declines to provide historical information prior to 2005 for the reasons given in L-12-6. Please refer to L-6-31 for actual FLR rates for OPG's nuclear generating units for 2005 - 2007.

b) With reference to actual versus budgeted FLR for 2005 – 2007, as set out at Ex. E2-T1-S2, Tables 2a and 2b, the FLR in 2005 and 2006 for OPG Nuclear was better or approximately on plan.

For 2007 the actual FLR was 11.7 percent versus a budget FLR of 5.4 percent. The two major one-time extraordinary events that have had significant generation impacts at Pickering but which are not expected to recur (Ex. E2-T1-S2, page 4) accounted for 7.2 percent of the FLR. Without these events, the FLR would have been 5.1 percent (i.e., under budget).

c) OPG's FLR over the period 2005 - 2007 shows a positive trend at Pickering A and Pickering B when the two major, non-recurring exceptions are excluded. See response to L-1-32. These major non recurring events are not age related. While OPG recognizes that aging plants will have more `material degradation issues' which can lead to an increase in the FLR, OPG is addressing that risk as part of its investments and work programs aimed at improving the material condition of the units as set out in Ex. E2-T1-S1, page 16.

Energy Probe Interrogatory #30

Ref: Ex. E2-T1-S1, page 9

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

OPG's evidence refers to "Known Risks" as one of the inputs to OPG's Forced Production Loss rate.

a) Does OPG expressly or formally forecast unknown risks that can cause Forced Production Losses? Please explain.

b) Please itemize the various "known risks" that have caused previous Forced Production Losses, and indicate for each one when it gained the status of "known risk".

c) For each of the past five (5) years, please describe the total FLR, and indicate what percentage of that total FLR was due to then-known risks and what percentage from other, then-unknown, risks.

d) For each reactor-year of Ontario's multi-year, multi-CANDU-unit outage (ca. 1997-2004), please indicate whether the loss of generation was attributed to a then "known" or "unknown" risk.

e) Was the many-year outage of Bruce Unit 2 -- widely attributed to the fact that a lead blanket was accidentally left behind during a maintenance outage -- attributed by Hydro/OPG to a "known" or an "unknown" risk?

Response

The evidence referenced at Ex. E2-T1-S1, page 9 refers to ‘known technological risks’. A ‘known technological risk’ is a production threat which is known to OPG due to operating experience (OPG or industry wide) or engineering analysis. OPG also recognizes known non-technological risks to production (e.g., labour issues as identified in part (c) above). Although the threat of occurrence is known, the specific timing is unknown and may cause a forced production loss at any time. As a corollary, unknown risks are assumed to be production threats for which there is potential forced production loss, but where a discrete issue has not been identified.

(a) Yes, OPG forecasts unknown risks that can cause forced production losses through the fleet-level risk adjustment. These forecasts take into account the potential for events that could impact the duration of a planned outage or the potential for forced

outages within the fleet, and the site-level force loss rate. Although these unknown risks are formally recognized as a risk element of the force loss rate forecast and fleet level adjustment, there is no specific delineation of unknown risks in the quantified force loss rate projection or fleet level adjustment.

(b) The following forced losses, which are presented in Ex. E2-T1-S2, Appendix C are known technological risks. OPG does not maintain a registry of when unknown risks are formally reclassified as known risks.

Darlington:

- D1 FO (Jan. 2005) Loss of low pressure service water (changing lake conditions)
- D1 FO (Sept. 2005) Screenhouse silt/algae
- D3 FEPO (Jun. 2006) Fuel handling labour issue
- D4 FO (Jan. 2006) Instrument tube failure

Pickering A:

- P4 FO (summer 2005) Feeder pipe elbow thinning
- P1 FO (Oct. 2006) Liquid Zone Control
- P4 FO (Oct. 2006) Liquid Zone Control

Pickering B:

- P6 FEPO (Dec. 2005) Shutdown cooling ("SDC") mechanical seal
- P5 FO (Aug. 2005) Screenhouse algae
- P6 FO (Aug. 2005) Screenhouse algae
- P7 FO (Jan. 2005) SDC mechanical seal
- P8 FO (Aug. 2005) Screenhouse algae
- P7 FEPO (Nov. 2006) SDC mechanical seal
- P8 FEPO (May 2006) SDC mechanical seal
- P5 FEPO (Jun. 2007) SDC mechanical seal
- -P5 FO (Jul. 2007) SDC mechanical seals
- P5 FO (Aug. 2007) Screenhouse algae
- P7 FO (Jun 2007) SDC mechanical seals

(c) Historical information for the period prior to 2005 is not provided for the reasons set out in L-12-6.

OPG does not statistically analyze FLR from the perspective of known versus unknown risks.

(d) Historical information for the period from 1997 - 2004 is not provided for the reasons set out in L-12-6.

(e) The referenced event at Bruce Unit 2 occurred prior to 2005. Historical information for the period from 1997 - 2004 is not provided for the reasons set out in L-12-6. Additionally, OPG does not statistically analyze force loss rate from the perspective of known versus unknown risks.

Energy Probe Interrogatory #31

Ref: Ex. E

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Was FLR forecast for OPG's nuclear units in past years? Was Availability or Capacity Factor forecast? For each "yes" answer, please provide the forecasts and the actuals for all available years since 2003.

Response

Yes, both force loss rate and capability measures (unit capability factor) were forecast in previous years on a unit basis (see table attached). Historical information for the period from 2003 to 2004 is not provided for the reasons set out in L-12-6.

Historical comparison of actual to plan (forecast) results for period from 2005 – 2007. Station results are weighted averages.

The following table provides Forced Loss Rate and Unit Capability Factor information for the period 2003 to 2007. Where available, data has been

	2005		2006		2007	
	Actual	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**
Unit Capability Factor						
Pickering 1	92.94	84.00	77.55	81.23	38.96	72.20
Pickering 2	-		-		-	
Pickering 3	-		-		-	
Pickering 4	66.67	69.22	66.51	75.90	43.71	92.00
Pickering 1-4	69.91	76.61	72.03	78.57	41.34	82.10
Pickering 5	53.73	54.83	90.09	93.00	58.06	78.50
Pickering 6	64.32	56.65	86.20	93.00	71.47	77.70
Pickering 7	97.95	91.00	59.25	75.02	82.42	93.80
Pickering 8	94.95	91.00	65.32	67.10	87.85	93.80
Pickering 5-8	77.74	73.37	75.21	82.02	74.95	85.96
Darlington 1	97.10	94.40	85.20	83.40	98.19	95.90
Darlington 2	79.78	79.90	99.42	95.90	83.38	77.80
Darlington 3	99.15	95.40	73.13	81.80	94.76	95.90
Darlington 4	86.50	88.14	97.11	95.90	81.48	78.90
Darlington 1-4	90.63	89.46	88.71	89.23	89.45	87.14
OPGN	84.39	82.48	81.94	85.31	77.49	86.22
Forced Loss Rate						
Pickering 1	7.06	16.00	19.09	12.00	50.77	8.00
Pickering 2	-		-		-	
Pickering 3	-		-		-	
Pickering 4	33.33	16.00	14.79	12.00	48.95	8.00
Pickering 1-4	30.09	16.00	17.16	12.00	49.82	8.00
Pickering 5	9.57	9.00	9.91	7.00	21.16	6.20
Pickering 6	3.07	9.00	4.22	7.00	8.13	6.20
Pickering 7	2.05	9.00	10.09	7.00	9.62	6.20
Pickering 8	5.05	9.00	3.05	7.00	12.15	6.20
Pickering 5-8	4.55	9.00	6.93	7.00	12.50	6.20
Darlington 1	2.90	4.60	1.82	4.10	1.71	4.10
Darlington 2	0.96	4.60	0.58	4.10	0.01	4.10
Darlington 3	0.83	4.60	8.52	4.10	0.02	4.10
Darlington 4	0.33	4.60	2.89	4.10	2.86	4.10
Darlington 1-4	1.31	4.60	3.24	4.10	1.14	4.10
OPGN	5.35	7.89	6.44	6.20	11.67	5.36

Energy Probe Interrogatory #32

Ref: Ex. E

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Based on information provided by OPG, an independent government-appointed task force predicted that the two refurbished reactors at Pickering-A would achieve Capacity Factors of 85%.

What was OPG's predicted probability of Pickering-A achieving actual Capacity Factors as low as those it has really attained since refurbishment? If that number is not available, please provide all available confidence data attached to those forecasts, including (but not limited to) 95% Confidence Intervals, Standard Deviations, etc.

Response

The average capacity factor ("ACF") range assumed for Pickering A Unit 1 in the OPG Review Committee report (2004) was 75 percent to 90 percent. At that time, OPG assumed that there was a 10 percent probability that ACF would be below 75 percent and a 5 percent probability that ACF would be above 90 percent.

The assumed ACF when the return to service decision was made back in 1999 on Pickering 4 was 85 percent. A range of 70 percent to 90 percent was also tested in sensitivity analyses.

Energy Probe Interrogatory #33

Ref: Ex. E

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

According to OPG's evidence, the Nuclear Integrated Plan "forms the basis for generating production targets in the business plan." Here and elsewhere in the evidence, we are confused by OPG's use of the words "target" and "forecast".

a) Does the word "targets" mean the same thing to OPG as "forecasts" or do they mean different things? Please explain.

b) In our experience, common English-language parlance uses "target" to signify a hopeful or aspirational prediction, and "forecast" to signify a most-likely or realistic prediction. If the words mean different things to OPG, are OPG's numbers -- e.g., for nuclear Forced Production Losses and Availability Factors -- to be taken as aspirational "targets" or realistic "forecasts"? If they mean the same thing, why are two words used instead of one?

Response

a) The word “targets” means the same thing as “forecasts”.

b) “Targets” and “forecasts” have been used interchangeably at OPG and denote a prediction of performance.

Energy Probe Interrogatory #34

Ref: Ex. E2-T1-S1, page 16

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

According to the evidence, Darlington NGS is implementing a three-year cycle for planned outages which we understand is "industry leading".

a) How long ago was this change made?

b) Are there any signs that other nuclear operators are following suit, or that they have decided not to? Please explain.

c) Has OPG received any correspondence or other indication from Bruce Power or Hydro Quebec or N.B. Power indicating their intentions?

Response

(a) As described in Ex. E2-T1-S1, Darlington started the transition to a three year outage cycle in the spring of 2006 with the Unit 3 outage and is presently completing the transition with the last unit in the 2008 spring outage.
(b) Other CANDU utilities have expressed interest in the three year cycle, but they have not made their specific intentions known to OPG.
(c) OPG has not received any correspondence from Bruce Power, Hydro Quebec or N.B. Power indicating their intention to transition to a three year outage cycle. However, Bruce Power has publicly presented at industry conferences an intention to implement a 30 month cycle.

Energy Probe Interrogatory #35

Ref: Ex. C2-T1-S1 page 65

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

In Exh. C2, reference is made to "the risk that the hydroelectric assets will not be dispatched." In OPG's Stakeholder Meeting materials, the statement was made that "The energy output from the [SAB energy production] model is adjusted to reflect factors . . . such as . . . spill loss due to excess base generation in the IESO system. . ."

How often and to what extent did "excess base generation" or non-dispatch affect OPG's output for each of the past five (5) years, and how often and to what extent is it forecast to do so in 2008 and in 2009?

Response

Non-dispatch or under-dispatch at the regulated facilities primarily occurs at Sir Adam Beck and is mostly due to automatic generation control, with a small amount due to excess baseload generation or other system requirements. OPG does not separate out the individual components of non-dispatch or under-dispatch. In addition, this information was not tracked prior to 2005. For the period of 2005 to 2007, spill losses due to under-dispatch were as follows:

Year	Losses Due to Non-Dispatch / Under-Dispatch (MWh)
2005	170,652
2006	166,040
2007	134,903

Trends of non-dispatch or under-dispatch, based on historical performance at Sir Adam Beck, were considered in compiling the hydroelectric production forecast for 2008 and 2009. An adjustment was made for each year, as described in Ex. E1-T1-S1, page 3, lines 9 - 11. This adjustment is a forecast amount which will differ from actual values due to market conditions.

Energy Probe Interrogatory #36

Ref: Ex. F2-T4-S1 and Ex. F2-T4-S2

Issue Number: 5.8
Issue: Is the methodology for deriving the nuclear outage OM&A budget and the forecast of outage OM&A costs appropriate?

Interrogatory

Do the two refurbished reactors at Pickering-A now have two separate and diverse and fully capable fast shutdown systems, capable of satisfying the CNSC design requirements that were in place for Bruce-B and Darlington NGS? Please distinguish carefully between an "Enhanced" SDS and a full two-fast-shutdown-system implementation.

Response

The shutdown systems in place satisfy the CNSC requirements for Pickering A.

The Pickering A reactors have two independent sensing and initiation systems (Shutdown System 1 [SDS1] and Shutdown System Enhancement [SDSE]) that activate the primary fast-acting shutdown mechanisms.

Energy Probe Interrogatory #37

Ref: Ex. F2-T4-S1 and Ex. F2-T4-S2

Issue Number: 5.8
Issue: Is the methodology for deriving the nuclear outage OM&A budget and the forecast of outage OM&A costs appropriate?

Interrogatory

The evidence (Exh. A1 / T 4 / S 3, p. 3) refers to "Evolving/Escalating Regulatory Standards" as a driver of nuclear costs, and states that "The requirement to meet nuclear safety regulations and standards imposed by the federal Nuclear Safety and Control Act, and the need to satisfy OPG's nuclear regulator, the CNSC, drives a large number of base OM&A work activities."

Is OPG aware of any instances where CNSC has required OPG to undertake safety-related changes -- including capital modifications and/or operating changes -- that OPG would not have undertaken in the absence of CNSC regulatory pressure? If so, please explain. If there are few or none, please explain the contrary implication of the evidence.

Response

It is important to understand the context of the evidence presented by OPG in the two separate references of this interrogatory response. The first referenced evidence (Ex. A1-T4-S3, page 3) "Overview of Nuclear Facilities" refers to "Evolving/Escalating Regulatory Standards" as a driver of nuclear costs is a general statement that, over time, standards within the industry change based on world/industry events or additional research information. The CNSC evaluates this new information and decides whether or not to imbed additional requirements into regulation. The industry (including OPG) is given an opportunity to provide input as to how these new standards would best be met and that information is evaluated by the CNSC as they are developing the new standards. The CNSC may or may not take the opportunity to incorporate industry feedback in the new regulatory standards. Because of the mandate of the regulator, a significant number of our activities are embedded in regulation.

The second referenced statement in the interrogatory response (Ex. F2-T2-S1, page 5) which states "The requirement to meet nuclear safety regulations and standards imposed by the federal Nuclear Safety and Control Act, and the need to satisfy OPG's nuclear regulator, the CNSC, drives a large number of base OM&A work activities" is only re-enforcing the earlier statement that most of our activities are imbedded in regulation and make up a large portion of our OM&A base work activities. Examples of events that drive new regulatory requirements are:

- Fire at Browns Ferry Nuclear Plant – drove significant changes to the fire protection programs at all nuclear facilities. These changes were important to safety and they were imbedded in the regulations and, while necessary, contribute the base OM&A work activities that you would not necessarily see in other industries.

- Terrorist attack of 9/11 – has driven significant changes to security programs throughout the industry. Again, to provide consistency across the industry and to ensure the safety of the public, these changes were imbedded in regulation. These changes were directed at the nuclear facilities (as opposed to other forms of electrical generation) and therefore the costs are unique to this industry and OPG.

None of these statements were meant to imply that these standards as imbedded in regulation are not necessary or prudent. They are illustrative of the introductory paragraph to Ex. F2-T2-S1, Section 2.1, page 5, which states “The nuclear industry stands apart from other regulated industries and other forms of electrical generation due to the nature of its technology, the criticality of safety in its operations and the nature of nuclear regulations”.

Given that the CNSC regulations are prescriptively included in our operating licenses, we are mandated to comply or not operate the facility. The CNSC clearly states that it is not an economic regulator. Its only mandate is to oversee public safety and the economic impact of the standards that are set is not a factor in its decision making. Given the regulatory environment in which OPG operates, in the majority of the cases, we take the lead to initiate changes in our work program based on changes in industry or proposed regulatory standards. The CNSC, like the utilities, looks to other jurisdictions to benchmark its activities and, based on these activities, changes in reporting and standards may occur.

Consequently, there are a number of key (cost) drivers that influence the level of base OM&A associated with OPGs nuclear operations to a degree not seen in other regulated activities.

Energy Probe Interrogatory #38

Ref: Ex. D1-T1-S1, page 3

Issue Number: 3.3
Issue: If the costs and financial commitments are not within project budgets approved by the board of directors of OPG, are the costs and financial commitments prudent?

Interrogatory

How will the delays in the construction of the Niagara Tunnel Project affect load forecasting in OPA's IPSP report going forward?

Response

In OPG's opinion, delays in the construction of the Niagara Tunnel Project will not affect load forecasting in OPA's IPSP report going forward.

Energy Probe Interrogatory #39

Ref: Ex. D1-T1-S1, page 3 - 4

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

a) Does OPG have any information intelligence, planned strategic scenarios, or other actionable methodologies to identify additional, future delays by the contractor for the Niagara Tunnel Project?

b) Did OPG anticipate NTP delays identified since 2006?

c) What plans does OPG have to anticipate further delays for the NTP?

How quickly (e.g. hours, days, weeks, months?) is OPG informed by the contractors when delays begin to occur or have occurred in the NTP?

Response

a) OPG and its Owner's Representative, routinely monitor schedule performance and forecasts by the contractor and review corrective actions with the contractor. Specifically the Owner's Representative is continually on site to monitor and map rock conditions as work associated with the project progresses. OPG project management staff attend weekly site meetings with both the Owner's Representative and the contractor. In accordance with the design build agreement for the Niagara Tunnel Project, the contractor is responsible for the construction schedule, is required to take corrective actions necessary to maintain the contract schedule and is required to pay liquidated damages for failure to meet the contract schedule.

b) The possibility of schedule delays associated with differing subsurface conditions was contemplated in OPG's approved business case for the Niagara Tunnel Project. The business case includes cost and schedule contingencies to address this risk. To date, the schedule delay on the Niagara Tunnel Project is directly related to slower than expected advance of the Tunnel Boring Machine.

c) See part a)

d) In accordance with the design build agreement for the Niagara Tunnel Project, the contractor provides OPG with monthly schedule updates and OPG's Owner's Representative routinely monitors the progress of the contractor.

Energy Probe Interrogatory #40

Ref: Ex. A1-T4-S2, page 17

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Please explain why "the two largest plants, Sir Adam Beck II and Saunders … [were] in the upper two quartiles for … availability and EFOR from 2003-2006.

Response

Since OPG does not have all the necessary comparative data on the design, maintenance/rehabilitation programs, planned outages, and modes of operation for the other stations in the peer groups for Sir Adam Beck II and R.H Saunders, OPG cannot explain why its two largest plants are generally in the upper two quartiles from 2003 to 2006. It is OPG's opinion, however, that the high availability factors of its two largest stations are generally a result of:

1. The prudent investment programs carried out from 1992 to 2005 to replace or upgrade major station components (see Ex. A1-T4-S2, pages 22 and 23 and Ex. E1-T1-S1, pages 5 and 6).

2. The adoption of streamlined reliability centred maintenance programs in 2002 (see Ex. A1-T4-S2, page 8).

Energy Probe Interrogatory #41

Ref: Ex. A1-T4-S2, page 11

Issue Number: 5.1
Issue: Are the Operational, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Please identify all external reports received by OPG on the Environment Performance Index from 2000 to the present.

Response

OPG has not received any external reports on the Environmental Performance Index from 2000 to the present.

Energy Probe Interrogatory #42

Ref: Ex. A1-T4-S1, page 15

Issue Number: 5.1
Issue: Are the Operational, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Please identify all external benchmarking reports commissioned by OPG since its inception.

Response

The information below identifies the benchmarking reports for Regulated Hydroelectric, Nuclear and Corporate based on data from 2005 and beyond. OPG declines to provide historical information prior to 2005 for the reasons given in L-12-6.

Regulated Hydroelectric

As indicated in Ex. A1-T4-S2, page 20, OPG started benchmarking all six regulated stations on a consistent basis in 2005. Reports using 2005 and 2006 data are listed below.

Year of Report	Data Year	Benchmarking Company/Organization Name	Type of Benchmarking Information
2007	2006	Haddon Jackson associates (now Navigant Inc)	- Includes cost and custom measures benchmarking, as well as limited reliability and safety benchmarking. - Annual Best Practices Workshop to discuss data/results.
2006	2005	Haddon Jackson associates (now Navigant Inc)	- Includes cost and custom measures benchmarking, as well as limited reliability and safety benchmarking. - Annual Best Practices Workshop to discuss data/results.
2007	2006	EUCG database	Cost and reliability benchmarking - US and Canadian Utilities
2006	2005	EUCG database	Cost and reliability benchmarking - US and Canadian Utilities
2007	2006	Canadian Electricity Association	Reliability Data - Several Canadian Utilities. Results not published by CEA yet. Expected May 2008.
2006	2005	Canadian Electricity Association	Reliability Data - Several Canadian Utilities
2007	2006	North American Reliability Council - Generation Availability Data	Reliability data benchmarking
2006	2005	North American Reliability Council - Generation Availability Data	Reliability data benchmarking

Witness Panel: Corporate and Other Operating Costs
Hydroelectric Core
Base OM&A and Fuels

Nuclear

In 2006, OPG commissioned Navigant Consultants to perform CANDU staffing benchmarking. A copy of the resulting report will be provided in L-3-050, if pending confidentiality issues are resolved. In addition, OPG is a member of WANO and EUCG and has access to their databases which contain benchmarking information.

Corporate

Corporate-wide benchmarking studies commissioned by OPG are listed below.

Year of Report	Data Year	Benchmarking Company/Organization Name	Type of Benchmarking Information
2006	2005	The Hackett Group	HR Benchmarking Review
2007	2006	The Hackett Group	Finance Benchmarking, Achieving World Class Performance
2005	2005	Mercer Human Resource Consulting	Management Compensation Review
2006	2006	Mercer Human Resource Consulting	Management Compensation Review
2007	2007	Mercer Human Resource Consulting	Management Compensation Review
2007	2007	Towers Perrin Human Resources Services	Competitive Executive Compensation Analysis
2006	2005	Gartner Consulting	Top Line IT Spending Summary
2006	2005	CIO Executive Board	IT Governance Maturity Diagnostic
2007	2006	Gartner Consulting	Top Line IT Spending Summary
2007	2006	EUCG	Information Technology Survey
2007	2006	NEI	Basic Information Technology and IT Applications Surveys

Energy Probe Interrogatory #43

Ref: Ex. A1-T4-S2, page 19

Issue Number: 5.1
Issue: Are the Operational, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Did the Haddon Jackson Associates report examine the matter of labour performance productivity? If so, in what manner was labour performance productivity treated? If labour performance productivity was not examined, why not?

Response

Haddon Jackson Associates ("HJA") does not study labour performance productivity using direct/detailed methods such as work flow analysis and activity/task complexity, duration, planning and coordination.

However, HJA does collect data on Full Time Equivalents ("FTE") for operations and maintenance activities. This data is used in conjunction with energy production and capacity data, to calculate indirect measures of labour productivity such as FTE/GWh and FTE/MW. These measures are only a gauge of labour productivity, since they do not use the detailed methods indicated above, and do not consider other important factors such as geography (travel distance/time), capacity factor or production of station (affects denominator), and vintage/complexity of station.

OPG does not know why HJA has not specifically examined labour performance productivity.