K12.1

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Energy Probe Cross-examination

Document Brief

OPG Panel #10: Cost of Capital

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significant proportion of their total fixed costs in a fixed customer charge, demand charge, or capacity payment. For example, the transmission utilities in Alberta collect 100% of their forecast revenue requirement in fixed monthly payments from the Alberta Electric System Operator. Gas pipelines regulated by the National Energy Board collect virtually all of their fixed costs in demand charges from shippers; electricity and gas distributors may collect up to 85% of their fixed costs in customer/capacity charges.[60] Based on the proposed payment structures for the prescribed assets (100% energy-based for hydroelectric assets and a fixed charge for nuclear assets covering 25% of forecast nuclear revenue requirement), OPG would recover approximately 20% of its total regulated costs in a fixed charge. Under this structure, the assurance of recovery of the regulated operations' fixed costs through fixed charges will be less, and the revenue risk higher, than for the typical Canadian utility.

Based on the OPG's rate application, the forecast 2009 information indicates that approximately 85% of OPG's revenue requirement other than return on equity and income taxes is comprised of expenses that are largely fixed (i.e., they do not vary directly with production). As the rate base declines over time, the dollars of return on rate base decline in absolute terms and in proportion to OPG's total fixed costs. In the absence of rate base growth (i.e., based on the existing prescribed assets, absent refurbishment), OPG's high fixed cost structure will continue to increase the sensitivity of the ROE to changes in revenues and expenses.

In contrast to electric and gas distribution utilities and vertically integrated (non-restructured) utilities, OPG does not have a defined franchise area, nor does it have an obligation to serve. The regulated generation competes in the Ontario market with OPG's unregulated generation and the generation owned by or leased by others (e.g. Bruce Power). At present, the competitive/market risks faced by OPG's regulated operations are relatively low, as the prescribed assets are primarily baseload facilities[61], with relatively low variable (marginal) costs

[60] For example, FortisAlberta collects approximately 85% of its fixed distribution costs in customer/demand charges; ATCO Electric Distribution collects approximately 65% of its fixed distribution costs in customer/demand charges.

[61] The Beck complex has some peaking capability.

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of production. There are, however, other generators whose marginal costs are similarly low (e.g., Bruce Power, wind generators, Brookfield Power), which can result in OPG's regulated facilities not being dispatched for short periods in which demand is relatively low. Nevertheless, dispatch risk for the regulated assets is currently relatively low. That risk will rise as additional low marginal cost generation (which can bid below cost but receive a price specified in its PPA with the OPA) becomes available or demand drops.

With respect to the impact of market prices on revenue risk, the market wholesale price of electricity in Ontario is set on the basis of supply of and demand for electricity, with the major driving factors being load, generator availability and fuel (e.g., natural gas) prices. OPG's regulated assets do not typically set the market-clearing price, except in cases of unutilized baseload capacity.[62] Since the payments for OPG's regulated generation are expected to reflect the total costs of production, including a reasonable return on invested capital, the revenue requirement is not based on market price factors.

B.2.b. <u>Production, Operating and Cost Recovery Risks</u>

Production, operating and cost recovery risks include all factors that may result in OPG under-recovering a reasonable return on investment and/or a part of the investment itself due to higher than anticipated costs of production, lower than anticipated production or loss of production. These factors are largely specific to the generation technology and are discussed in the individual hydroelectric and nuclear operations sections that follow.

B.2.c. <u>Regulatory Risks</u>

With respect to economic regulation, regulation has the power to expose utilities to enormous risks, by disallowing costs, approving rate structures that are incompatible with the cost

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[62] As additional low marginal cost generation becomes available, and the potential for unutilized baseload capacity correspondingly rises, OPG's prescribed assets will increasingly determine the market-clearing price.

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For the 2008 - 2009 test period, the forecast number of planned outage days is 254 days in 2008 and 343 in 2009. This is a significant reduction from the 386 outage days (346 planned outage and 40 forced extension to a planned outage) experienced in 2005 and the 490 outage days (324 planned outage and 167 forced extension to a planned outage) experienced in 2006. Similarly, the FLR for the combined fleet of nuclear assets is expected to improve, with an anticipated drop from 11.7 percent in 2007, to a target of 4.2 percent by 2009. This improvement in the forecast FLR for the combined fleet in 2009 reflects the improved operating experience at Darlington and Pickering B which has allowed a reduction in the FLR target to 2 percent and 5 percent respectively offset by the ongoing reliability challenges at Pickering A reflected by an increased 2009 FLR target of 10 percent.

4.0 OPG NUCLEAR INITIATIVES TO IMPROVE OUTAGE PERFORMANCE AND PRODUCTION

OPG has implemented or is undertaking a number of initiatives to improve outage performance, the benefits of which are anticipated to emerge over time, including:

- Improving Outage Planning: Previous outage planning, particularly at Pickering B, was focused on major initiatives such as the spacer location and relocation program, resulting in "non-routine" outages typically longer than 100 days. OPG's expectation moving forward is that there will be shorter duration, "routine" planned outages, supported by the following initiatives:
    - Commencing in 2006, OPG began implementing improved industry-standard outage planning milestones in the planned outage process, to transition to industry best practices. Examples of the standard planning milestones are shown in Appendix B. The milestones are used to improve outage management by facilitating better outage planning. The milestones define and describe discrete deliverables, accountabilities, timeframes, due dates for completion, and the criteria to be used to verify completion of the deliverable. The revised process also establishes requirements for earlier identification of labour and material requirements in support of annual business planning and the Supply Chain initiative described below.

(4)

While estimated unit availability and production are based on estimates that include past unit history and an understanding of the condition of the assets, the higher the capacity factor that is built into the forecasts, and the payments, the more asymmetry there is in the risk of exceeding versus falling short of forecast availability.

OPG faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities. Every one TWh shortfall in production at a variable payment of $40 per MWh, which approximates the average variable portion of OPG's proposed nuclear payment amounts in Exhibit K1, Tab 3, Schedule 1, is equal to an approximately $40 million reduction in revenues. Since approximately 5.0% of the costs of nuclear production are variable, i.e., fuel costs (as per OPG's Exhibit I1-2-1), a $40 million reduction in revenues would reduce earnings from nuclear generation by approximately $25 million,[75] equivalent to a reduction in return on equity of approximately 0.6 percentage points relative to the total deemed equity ($4200 million) for the prescribed assets for 2008. To put this in perspective, in 2006, actual nuclear production fell 2.5 TWh below forecast. A 2.5 TWh production shortfall translates into a reduction in ROE of approximately 1.5 percentage points. It is important to note that the reduction in ROE would be higher if the proposed change in payment structure is not approved.

OPG's nuclear facilities are subject to the oversight of the Canadian Nuclear Safety Commission (CNSC), whose mandate is to protect the health and safety of persons and the environment, and to ensure national security from risks associated with the use of nuclear energy and nuclear material. The CNSC is responsible for licensing nuclear facilities during each of five phases in a nuclear plant's life cycle, site preparation, construction, operation, decommissioning and abandonment. In fulfilling its mandate, the CNSC has the ability to impose conditions of licenses, including, among other things, increased security requirements – which have become

[75] Equal to a reduction in revenue of $40 million less $2.0 million in variable costs, equivalent to $25 million in after-tax earnings at a 34% tax rate.

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In addition to the above:

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

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

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

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

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

DESIGN OF THE HYDROELECTRIC PAYMENT AMOUNTS

1.0 PURPOSE

This evidence provides a description of the proposed structure of the regulated hydroelectric payment amounts for the test period, which includes an incentive mechanism to encourage efficient use of the peaking capability of the regulated hydroelectric facilities.

2.0 HOW THE REGULATED ASSETS OPERATE WITHIN THE MARKET

OPG's regulated hydroelectric facilities and nuclear facilities operate as dispatchable generators in the IESO administered market. OPG is required to submit hourly offers to inform the IESO how much energy it has to sell and at what price. The IESO uses the offers and bids submitted by all dispatchable market participants (generators and loads), as well as transmission system information, to determine when and how much energy a dispatchable generator should provide. Dispatch instructions computed by the IESO's dispatch algorithm are issued for each five minute interval of the day, 24 hours per day, and 365 days per year. These instructions specify the generator's operating point for each five minute interval. The market clearing price[1], calculated by the IESO's dispatch algorithm, is used for two purposes. One, it is used to provide the market a price signal which indicates the marginal price of energy supply to meet the demand. Two, it is used for settlement purposes[2], with specific exceptions applied to OPG by O.Reg. 53/05.

Dispatchable generators are expected to respond to dispatch instructions that are issued every five minutes. Generators have different capabilities in following these instructions. Due to physical, regulatory or safety constraints, some generators are better suited to steady state operation with little or no deviation from a constant operating point. These generators are characterized as baseload. Other generators are well suited to quick and frequent

[1] Market clearing price is a market based price which is indicative of the marginal cost of energy supplied in order to meet demand. OPG's regulated assets do not receive market clearing price for energy delivered except for the production from the hydroelectric assets above 1900 MW.

[2] The regulated price for settlements is calculated after the fact. The IESO adjusts the market clearing price that OPG regulated generators receive, to the price set out in O. Reg. 53/05.

changes in output over a short period of time. These generators are characterized as peaking facilities. In terms of OPG's regulated assets, all of the nuclear and some of the hydroelectric stations are best suited for baseload (steady state) operation. While the majority of the peaking capability from OPG's regulated facilities is provided by the Sir Adam Beck Complex largely because of the integrated operation of the Sir Adam Beck Pump Generating Station ("PGS") within the complex, DeCew Falls and R.H. Saunders each have some minor peaking capability as well.

2.1 Hydroelectric Offer Strategy

The operating constraints for hydroelectric generators, such as water flow and elevation limits, are externally specified (see Ex. A1-T4-S2 for a discussion of the regulatory and legislative environment). A hydroelectric generator cannot follow a dispatch instruction that would cause it to violate a prescribed regulatory limit.

Hydroelectric generators that cannot readily respond to dispatch instructions every five minutes operate as baseload units and are offered into the market as price takers.[3] R.H. Saunders can be regarded as a baseload plant, as it has a very small peaking capability relative to its overall output. The facilities that comprise the Niagara Plant Group, collectively, have baseload as well as peaking capability, subject to prevailing water conditions.

As demand for electricity increases to its maximum, or peak value, generation supply is dispatched by the IESO to meet the demand. Progressively more expensive supply is dispatched as demand increases until the supply/demand equilibrium is achieved. There is a strong causal relationship between the supply/demand balance and the market clearing price. Generally, the lower the amount of available supply relative to demand, the higher the market clearing price.

[3] An offer price is the price at which a generator is offered into the market. The level of the offer price generally affects the outcome of the dispatch instruction from the IESO. Baseload generators are generally priced as 'price takers', meaning that their offer price is positioned well below the expected market clearing price. This is a recognized pricing strategy for ensuring steady state operation and avoiding marginal economic dispatch instructions.

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OPG's regulated hydroelectric facilities currently receive a financial incentive to provide peaking supply in response to demand. Ontario Regulation 53/05 states that electricity production above 1900 MW will receive the market clearing price instead of the regulated rate (currently $33/MWh). For production from all regulated hydroelectric facilities at or below the 1900 MW production threshold, OPG receives the regulated rate. By utilizing market price signals, the regulated hydroelectric facilities can, when capable, produce more energy in high demand periods relative to lower demand periods. In such circumstances, both the market and OPG benefit. The market will benefit by having a peaking energy resource available during high demand periods offsetting otherwise more expensive generation resources or, in the extreme, preventing a scarcity situation in which the supply of the system was inadequate to meet demand. In turn, as is more fully described in section 3.0, ratepayers benefit through lower Ontario market prices. OPG financially benefits by shifting production to higher demand periods, thereby receiving the market clearing price, which is generally higher than the regulated payment amount.

3.0 VALUE OF REGULATED PEAKING ASSETS TO THE MARKET AND THE RATEPAYER

Given the importance of OPG's regulated hydroelectric facilities in meeting Ontario's electricity needs, it is crucial that these facilities be operated in a manner that maximizes their economic value to consumers. In particular, it is essential that the peaking capability of these facilities be utilized to meet peak system demands. The regulatory approach governing these facilities should provide the proper incentives to operate these facilities efficiently and in a manner that maximizes the value of their production.

Maximizing the value of the regulated assets involves time-shifting hydroelectric production into the hours of the day when demand and thus price are both generally at their highest. Operating the regulated hydroelectric facilities in this way ensures that the greatest amount of regulated hydroelectric production is available when it is most beneficial to customers and can displace typically more expensive peaking generation, which otherwise would be used. This activity is often referred to as "peak shaving".

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IMPLEMENTATION OF A DEEMED CAPITAL STRUCTURE

The use of a deemed capital structure requires matching the capital structure to the rate base. The rate base, in principle, in its entirety is intended to be a representation of the amount of investor-supplied capital required to provide utility service. Ratepayer provided funds that are used to finance utility assets represent no cost capital. No cost capital (e.g., deferred taxes) should be deducted from rate base (or included in capital structure at a 0% cost rate).

To the extent that there are no specific debt issues that can be separately identified with the unregulated operations, actual long-term debt can be attributed to the deemed capital structure to the extent required to bring the rate base and deemed capital structure into balance. If the deemed equity and allocation to the utility capital structure of 100% of the actual long-term debt available does not equate rate base and capital structure, i.e., capital structure remains lower than rate base, the remaining gap is "plugged" by deeming sufficient debt to create a balance between the two.[119] The choice of short-term or long-term debt as the "plug" should be based on the nature of the shortfall between the two.[120] If, for example, the difference is primarily attributable to differences in the way working capital is estimated for regulatory purposes (lead/lag study) versus financial statement purposes, reflecting seasonal usage of short-term debt, the plug should attract a short-term debt cost. If, however, the difference were attributable to deeming a lower common equity ratio than the actual equity available, the "plug" should reflect the long-term nature of the assets and thus be deemed as, and costed at, a long-term debt rate.

[119] In its *Report* for the electricity distributors, the Board has fixed the short-term debt proportion at 4% of rate base. A cap on the short-term debt would require any additional "plug" that is required to equate rate base and capital structure to be deemed as long-term debt.
[120] In certain cases, where actual equity exceeds the deemed level, the "plug" is a reduction to capitalization. The cost rate on the "plug" has typically been deemed at a cost that reflects the rate achievable if the excess capitalization had been invested.

> very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[141]

2. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available;

[141] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

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(b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table C-5

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 6, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table C-5 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2006, the longest period for which data for the new

2006 were eliminated, as were those companies with fewer than five years of market data available (leaving 43 companies). To ensure that relatively low risk unregulated companies were selected, all companies with five-year "raw" betas ending December 2006 over 1.0 were removed. The resulting group contained 40 companies.[149] Next, those companies whose 1994-2006 returns fall outside ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable (30 companies remaining). Finally, those companies whose stock was ranked "Higher Risk" or "Speculative" by the Canadian Business Service (CBS),[150] whose debt is rated non-investment grade i.e., BB+ or below by either DBRS or Standard & Poor's, or for which none of the agencies report a rating, were eliminated. The final sample of low risk Canadian industrials is comprised of 20 companies (Schedule 16).

TIME PERIOD FOR MEASURING RETURNS

Since industrials' returns on equity tend to be cyclical, the appropriate period for measuring industrial returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1994-2006 encompasses both years of economic expansion and contraction. Over the period 1994-2006, the experienced returns on equity of the sample of 20 industrials were as follows.

[149] SNC-Lavalin was removed due to its purchase of regulated electric transmission assets in Alberta; Canadian Pacific Railway was also eliminated due to its reorganization in 2000, which rendered its historic data series inconsistent; Canadian National Railway was removed as it was controlled by the Federal Government through November 1995; Foremost Income Fund and North West Co. Fund, were removed because they are income trusts.
[150] Canadian Business Service (CBS) ranks stocks "Very Conservative", "Conservative", "Average", "Higher Risk", or "Speculative".

Table F-1

Returns on Average Common Equity for Low Risk Canadian Industrials (1994-2006)

Average	13.3%
Median	12.8%
Average of annual medians	13.3%

Source: Schedule 17.

Based on these data, the returns are in the approximate range of 12.75-13.25%.

The average nominal economic growth for Canada during the 1994-2006 business cycle was 5.4%, compared to the consensus forecast for real growth of 2.7%, and for inflation (CPI) of 2.0% for the period (2008-2017)[151], which suggests nominal long-term GDP growth of approximately 4.75%. While nominal growth is expected to be moderately lower relative to the past business cycle, the experienced returns on book equity, absent extraordinary events, provide a reasonable proxy for the future.

[151] Consensus Economics, *Consensus Forecasts*, April 2007.