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EB-2007-0905

AMPCO Cross-Examination

Document Brief

OPG Panel #10:
Cost of Capital

1 of 23

B.3. Business Risks of the Hydroelectric Operations

B.3.a. Revenue and Market-Related Risks

Revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. While the costs of the hydroelectric operations are largely fixed, OPG's proposed payment structure for production from its prescribed hydroelectric assets reflects a rate that is 100% energy-based. In isolation, the payment structure exposes OPG to higher revenue risks than the typical regulated company, which recovers a portion of its fixed costs in demand or customer charges.

Revenue risks also include the risk that the hydroelectric assets will not be dispatched. Dispatch risk remains low at present for the hydroelectric assets, as they are largely baseload facilities,[67] with low marginal costs. However, this risk will rise as additional low marginal cost generation becomes available. The emerging risk that OPG's prescribed assets are not dispatched and there will be unutilized baseload capacity will impact the hydroelectric facilities first.

Market prices are expected to directly impact regulated operations only through the operation of proposed hydroelectric incentive mechanism. Under the proposed Hydro Incentive Mechanism, OPG will be financially obligated to supply a given amount of energy each hour (Hourly Volume). It would receive the regulated payment for each MWh up to the Hourly Volume and the market clearing price for each MWh of energy in excess of the Hourly Volume. If OPG fails to supply the Hourly Volume for which it is financially obligated, its payments will be reduced by the difference between the amount supplied and the market price. Although the incentive mechanism and its reliance on market prices do not impact the determination of the revenue requirement (i.e., the revenue requirement is based on the total costs of providing service, not market prices), its operation can impact the recovery of the revenue requirement. While OPG's

[67] As indicated earlier, the Beck complex has some peaking capability.

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AMPCO Interrogatory #6

Ref: Ex. C2-T1-S1, page 65 - "Revenue risks also include the risk that hydroelectric assets will not be dispatched."

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

Please indicate the number of hours since IESO market opening, excluding periods of market interruption such as August 14-16, 2003, in which prescribed hydroelectric assets which had been offered into the IESO market were not dispatched. Also, indicate which assets failed to be dispatched (e.g. Beck peaking versus Beck baseload) and whether these were hours in which prescribed hydroelectric asset production was > 1,900 MW.

Response

According to OPG's Electricity Generation Licence from the OEB (EG-2003-0104), OPG is obligated to offer all available capacity into the IESO administered market in all hours[1]. As the prescribed hydroelectric assets are energy limited resources, all capacity offered into the IESO market may not be dispatched for energy. Some of this offered capacity will be dispatched by the IESO for operating reserve and automatic generation control. In addition some of this offered capacity may also not be dispatched for market reasons, such as, constrained off situations to address reliability and due to excess baseload generation.

All offered capacity from the prescribed hydroelectric assets has not been dispatched in almost every hour since the Ontario market opening in May 2002 (excluding the periods of market interruption in August 2003). In most cases, it was the peaking energy that was not dispatched.

[1] Part 5 a) of the licence obligates OPG to offer the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each unit capable of providing such services. Since operating reserve offers require a corresponding energy offer, OPG is obligated to offer all available capacity.

for purposes of establishing an appropriate capital structure and return on equity for OPG's regulated operations.

OPG potentially faces significant capital expenditures to build new large scale hydroelectricity facilities. The requirement to build a new large scale hydroelectric generation facility would entail an extended period between development, construction and putting those assets into service. Allowing CWIP in rate base in a period of high capital expenditures would help mitigate the corresponding increase in risk. As discussed above, my recommendations are premised on the inclusion in rate base of CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, including the refurbishment of a nuclear facility or a new build. Since OPG is not applying to include CWIP in rate base at this time, the size and duration of generation-related capital projects expose it to higher forecasting and regulatory risks than other OEB regulated utilities.

B.4. Business Risks of the Nuclear Operations

B.4.a. <u>Revenue and Market-Related Risks</u>

As discussed earlier, revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. Except for the fuel costs, which make up a relatively small proportion of the total nuclear operations' cost structure, the costs of nuclear production are largely (over 90%) fixed. The proposed nuclear payment structure will collect 25% of OPG's forecast revenue requirement in a fixed charge. Under this structure, the assurance of recovery of the nuclear operations' fixed costs through fixed charges will still be less, and the revenue risk higher, than for the typical Canadian utility.

Revenue risks for nuclear operations include the risk that the generating plants will not be dispatched. Dispatch risk is low at present for the nuclear assets, as they are baseload facilities

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with low marginal costs. The risk to the nuclear operations that there will be unutilized baseload capacity will rise as additional low marginal cost generation becomes available. This is particularly problematic for nuclear generation, given the time required for the plants to ramp production up and down. No allowance for this emerging risk has been included in the forecast production.

The Board Report raises a risk that regulated revenues will be indirectly impacted by the market price, as it raises the spectre of caps on regulated payments if they exceed the market price for an extended period of time. This risk would principally impact nuclear production. Application of a cap based on market prices in the context of cost of service regulation would be an anomalous practice. Given that (1) the interim price for nuclear generation of $49.50 per MWh only included a 5% return on equity, and (2) OPG is facing potentially significant future cost increases (e.g., decommissioning costs), a cap on regulated payments tied to market prices could impair OPG's ability to earn a compensatory return.[72] The risk assessment proceeds on the assumption that the Board will not impose a cap on regulated payments tied to market prices.

B.4.b. <u>Production, Operating and Cost Recovery Risks</u>

The production/operating risks related to the nuclear assets are significantly higher than those of the hydroelectric generation facilities (and are higher than those of any other types of generation).[73] Nuclear technology is more complex than other types of generation and is subject to higher risks of unanticipated costs of repair and loss of production.

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[72] For some perspective, the weighted average Hourly Ontario Electricity Price was approximately $48.50/MWh during 2006, compared to the price of $53.38 that had been forecast for 2006 in March 2005 by Navigant Consulting in *Ontario Wholesale Electricity Market Price Forecast for the Period January 1, 2006 through December 31, 2006*, largely due to lower than anticipated load and lower than anticipated natural gas prices.

[73] According to Standard & Poor's,

> Nuclear generating assets have significant operational and technology risks. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in the past. (Standard & Poor's, *Summary: Ontario Power Generation, Inc.*, April 24, 2007.)

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AMPCO Interrogatory #9

Ref: Ex. C2-T1-S1, page 68 - "Revenue risks for nuclear operations include the risk that generating plants will not be dispatched".

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

Please provide the number of hours since IMO/IESO market opening, excluding periods of market interruption such as August 14-16, 2003, when prescribed nuclear assets which were offered into the IESO market were not dispatched (for market reasons i.e. not subject to congestion-related curtailment).

Response

The information requested is not available within OPG.

Consistent with Ex. A1-T4-S3, page 1, lines 15 - 16, nuclear units are typically baseload resources designed to operate at full power. Therefore, maneuvering of these units is something to be avoided, if at all possible. For this reason, the number of occurrences where nuclear assets, which were offered into the IESO market, were not dispatched since market opening (for market reasons i.e., not subject to congestion related curtailment) would be very few.

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Filed: 2007-11-30
EB-2007-0905
Exhibit A2-3-1
Attachment B

STANDARD & POOR'S CANADIAN RATINGS

Publication date: 09-Dec-2005
Reprinted from RatingsDirect

Ontario Power Generation Inc.

Primary Credit Analyst: Nicole Martin, Toronto (1) 416-507-2560; nicole_martin@standardandpoors.com
Secondary Credit Analyst: Laurie Conheady, Toronto (1) 416-507-2518; laurie_conheady@standardandpoors.com

Corporate Credit Rating

BBB+/Positive/--

Financial policy:
Moderate
Debt maturities:
2006 C$800 mil.
2007 C$400 mil.
2008 C$400 mil.
2009 C$350 mil.
2010-2012 C$1,745 mil.

Outstanding Rating(s)	
Ontario Power Generation Inc.	
CP	
Local currency	A-2
Ontario (Province of)	
Corporate Credit Rating	AA/Stable/A-1+
Sr unsecd debt	AA
Hydro One Inc.	
Corporate Credit Rating	A/Stable/A-1
Sr unsecd debt	
Local currency	A
CP	
Local currency	A-1

Corporate Credit Rating History	
Oct. 12, 2001	BBB+

Major Rating Factors

Strengths:

- Dominant position in a market with a strong and diversified economic base
- Government ownership and implied financial support
- Diversified portfolio of generating assets
- Low cost hydroelectric assets with river system diversity

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Weaknesses:

- Uncertain sales volumes due to seasonality of electricity demand, variability in both river flows and asset operating performance
- Below-average financial profile related to low allowed returns on

regulated operations and an interim revenue cap on nonregulated operations
- Operational challenges at nuclear and coal-fired facilities
- Nuclear technology exposes company to significant risk and potential for unexpected large capital expenditures

Rationale

The ratings on Ontario-based electricity generator Ontario Power Generation Inc. (OPG) reflect the close relationship between the company and its higher rated owner, the Province of Ontario (AA/Stable/A-1+). Secure cash flows derived from OPG's regulated nuclear and regulated hydroelectric assets, a diverse portfolio of generating assets, and a strong cost competitive position in the Ontario wholesale electricity market further support the ratings. These strengths are partially offset by operational and technology risk associated with its nuclear assets, volume risk related to OPG's unregulated coal and hydroelectric assets, a price cap on the bulk of unregulated commodity sales, and a below-average but improving financial position.

OPG's ownership by the province significantly enhances the creditworthiness of the company. The close relationship between OPG and the province is expected to continue. This view is supported by the company's strategic position in Ontario's electricity sector and overall economy. The province's demonstrated willingness to financially assist the business and stated intention to continue to direct the company's future investments in major new generation is further evidence of a close relationship. The province has made a commitment to provide OPG with 100% debt financing for the C$1 billion Niagara tunnel project announced in September 2005. All of OPG's long-term debt is in the form of notes payable to the province. Furthermore, the likelihood of the privatization of OPG or further divesting of significant assets appears low.

Cash flow from all of OPG's nuclear production and a portion of its hydroelectric production is supported by a legislated fixed price of C$49.50 per MWh and C$33 per MWh respectively, until 2008. Based on forecast production, operating costs, and existing capital structure, the company should be able to earn about a 5% return on equity from its regulated operations that generate more than half of energy revenues. The ability to recover significant unexpected capital and operating costs offsets some of the potential negative financial impact related to the company's inherent operational risks. Cash recovery of these costs, if approved by the regulator, would be unlikely to begin before 2008 and could be spread out over a three-year period. If necessary, the generator may apply for a price increase before the implementation of full regulatory oversight by the Ontario Energy Board (OEB; the province's independent regulator) expected in 2008.

The fuel diversity and large number of units in OPG's generation portfolio mitigate the risk of operational disruptions and enhance the company's business position. The portfolio includes base-load nuclear (6,618 MW), predominantly run-of-the-river hydroelectric (6,962 MW), intermediate coal-fired (6,438 MW), and peaking gas- and oil-fired (2,140 MW) generation assets. Furthermore, OPG's hydroelectric assets are on multiple river systems, the diversity of which serves to partially offset OPG's exposure to hydrology risk. All told, the company's asset base includes more than 75 generating units with capacity ranging from 50 MW to more than 800 MW each.

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OPG has a strong cost-competitive position in its primary market. The combined output of the generator's base-load regulated assets (about 60 TWh per year) is among the lowest cost generation in the province and is not exposed to significant dispatch risk. The Ontario electricity market can absorb all available nuclear generation output from OPG and its competitor Bruce Power Inc. (Bruce Power). OPG's unregulated hydroelectric generation can easily compete with higher cost oil- or gas-fired production to meet intermediate and peaking demand in the Ontario electricity spot market. Further strengthening its market position, OPG is the only Ontario-based coal-fired generator and the dominant player in the Ontario market, producing two-thirds or more of the approximately 150 TWh of electricity sold in Ontario each year.

There is significant operational and technology risk associated with nuclear generating assets. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in recent years. Although similar in concept, each station has design differences that add to the complexity of monitoring and maintaining their performance. OPG has a nuclear liability risk-sharing agreement with the province that caps the company's used nuclear fuel liabilities. Furthermore, OPG will have access to segregated funds to manage the costs associated with used fuel and eventual nuclear decommissioning. Until 2008 OPG is required to make a cash payment of C$454 million per year to the fund. Post 2008, annual contributions are scheduled to be reduced by about 15% but will remain a significant and ongoing drain on funds from operations (FFO) available to meet the company's debt and interest obligations.

Cash flow derived from OPG's unregulated coal-fired and hydroelectric assets is exposed to variability in production. Although cost-competitive with oil- or gas-fired generators, OPG's coal-fired fleet is exposed to competitively priced imports from neighboring markets. Furthermore, wear and tear on the coal-fired plants, that frequently ramp up and down, result in maintenance outages that can also reduce total output. Volume risk associated with OPG's unregulated hydroelectric production is due to the inherent uncertainty of available water flows. The reliability and availability of OPG's hydroelectric assets, however, is strong. OPG does not have significant water storage capability but is able to take some advantage of peak prices on a daily and weekly basis.

Until April 30, 2006, there is a C$47 per MWh revenue cap on approximately 85% of production from OPG's unregulated assets that limits the company's opportunity to increase cash flow from spot market sales. At the same time, the price cap on unregulated production is not a guaranteed floor. A small portion of OPG's cash flow remains exposed to volatile commodity prices. Given rising energy and electricity prices and the track record of government price setting in Ontario, there is some risk that the revenue cap will be extended.

Although OPG's financial profile has been weak in the past several years, it has shown improvement in 2005 and is expected to continue to strengthen in 2006. In assessing OPG's key credit ratios, such as FFO interest coverage and FFO to total debt, cash payments to segregated nuclear liability funds are deducted from cash flow from operations. Based on forecast production and the regulatory pricing scheme implemented May 1, 2005, FFO interest coverage could exceed 4x in 2005, after taking into consideration cash rebate payments related to the revenue cap due in May 2006, as compared with 3x coverage achieved in 2004. Furthermore, assuming the C$47 per MWh revenue cap on OPG's nonregulated output is removed as of May 1, 2006, and a full year's production from a second refurbished nuclear unit is achieved, FFO interest coverage could exceed 5x in 2006. On the same basis, FFO-to-total-debt is expected to increase to about 17% in 2005 and to or above 20% in 2006, as compared with about 10% in 2004. Total-debt-to-total-capital on an adjusted basis is expected to be about 42% in 2005 but based on the company's current plans for debt reduction, could improve in 2006 and 2007. On a forward-looking basis, given significantly higher FFO and lower capital expenditures, the company anticipates being in a position to repay C$1.2 billion in debt maturing in 2006 and 2007 that would contribute to further improvement in cash flow credit metrics. The extent of this marked improvement to cash flow adequacy, however, is subject to market price volatility, the lifting of the revenue cap, and the operating performance of OPG's generating assets, in particular its nuclear fleet.

Liquidity

Based on available credit lines, cash, expected cash flow, and demonstrated support from its government shareholder, OPG's liquidity should be sufficient to meet cash outlay commitments in the next 12 months.

OPG's C$1 billion fully committed credit facility has a C$500 million 364-day term tranche maturing May 23, 2006, and a C$500 million three-year term tranche maturing May 23, 2008. The facility serves as a backstop to the generator's C$1 billion CP program. At Sept. 30, 2005, the full amount under the credit facility remained available as no CP had been issued and the bank line remained undrawn. The C$1 billion bank facility remains available to support collateral requirements that could arise from the company's exposure to commodity market-related financial settlement risk. In addition, as of Sept. 30, 2005, OPG had about C$215 million (unaudited) under its separate standby LOC facilities, and C$549 million in cash and cash equivalents. A significant portion of the company's cash on hand is earmarked for rebate payments, due in May 2006, related to the C$47 per MWh revenue cap.

Based on average production of about 110 TWh and assuming the C$47 per MWh revenue cap on output from nonregulated assets is removed effective May 2006, OPG can expect to generate more than C$1 billion in FFO in 2006. Capital expenditures of about C$500 million (excluding the Niagara tunnel project) are anticipated in 2006, similar to about C$540 million in 2005. Given significantly improved earnings, the company is expected to resume dividend payments based on its 35% payout policy expected to be equivalent to about C$250 million in 2006. OPG plans to use any remaining cash flow to pay down debt maturing in 2006. Ongoing financial support from its shareholder enhances OPG's liquidity. Earlier in 2005 OPG borrowed an additional C$495 million from its shareholder to partially fund its 2005 cash requirements. OPG has access to a further C$200 million in preapproved funds from its shareholder until March 31, 2006.

Outlook

The positive outlook reflects the expectation of a significant improvement to OPG's cash flow and credit metrics in 2006 due to increased nuclear output and a full year of higher regulated prices. The anticipated removal of the C$47 revenue cap on 85% of OPG's unregulated output as of May 1, 2006, should also contribute to an improved financial position in 2006 and 2007. The positive outlook is further supported by the expectation of a period of relative stability in both Ontario's electricity policy and regulatory framework, and increasing transparency in decisions affecting the company's financial profile. The outlook could be revised to stable as a result of lower-than-expected market prices or significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities. A material change in the shareholder relationship is not expected to lead to a higher rating but could lead to a lower rating. Should the expected improvement in cash flow credit metrics materialize in 2006 and be considered sustainable in years beyond, the rating will likely move a notch

B.3. Business Risks of the Hydroelectric Operations

B.3.a. Revenue and Market-Related Risks

Revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. While the costs of the hydroelectric operations are largely fixed, OPG's proposed payment structure for production from its prescribed hydroelectric assets reflects a rate that is 100% energy-based. In isolation, the payment structure exposes OPG to higher revenue risks than the typical regulated company, which recovers a portion of its fixed costs in demand or customer charges.

Revenue risks also include the risk that the hydroelectric assets will not be dispatched. Dispatch risk remains low at present for the hydroelectric assets, as they are largely baseload facilities,[67] with low marginal costs. However, this risk will rise as additional low marginal cost generation becomes available. The emerging risk that OPG's prescribed assets are not dispatched and there will be unutilized baseload capacity will impact the hydroelectric facilities first.

Market prices are expected to directly impact regulated operations only through the operation of proposed hydroelectric incentive mechanism. Under the proposed Hydro Incentive Mechanism, OPG will be financially obligated to supply a given amount of energy each hour (Hourly Volume). It would receive the regulated payment for each MWh up to the Hourly Volume and the market clearing price for each MWh of energy in excess of the Hourly Volume. If OPG fails to supply the Hourly Volume for which it is financially obligated, its payments will be reduced by the difference between the amount supplied and the market price. Although the incentive mechanism and its reliance on market prices do not impact the determination of the revenue requirement (i.e., the revenue requirement is based on the total costs of providing service, not market prices), its operation can impact the recovery of the revenue requirement. While OPG's

[67] As indicated earlier, the Beck complex has some peaking capability.

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Board Staff Interrogatory #12

Ref: Ex. C

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

Ms. McShane notes on page 59 that there are other generators whose marginal costs are similarly low, which can result in OPG's regulated facilities not being dispatched and concludes "That risk will rise as additional low marginal cost generation" becomes available. Is this referring to the natural gas generators that have recently contracted with the OPA as being lower marginal cost generation relative to OPG's nuclear and hydro facilities? If so, please identify some examples that would pose dispatch risk for OPG's nuclear and hydro facilities. If not, please clarify the reference to "additional" generation.

Response

In this context, low marginal cost generation is in reference to the announced new wind power projects and the Bruce A refurbishment project. These generators can offer a low marginal cost but they will receive a price specified in their Power Purchase Agreement with the OPA. These units may pose a dispatch risk for OPG's nuclear and hydro facilities during periods of low demand.

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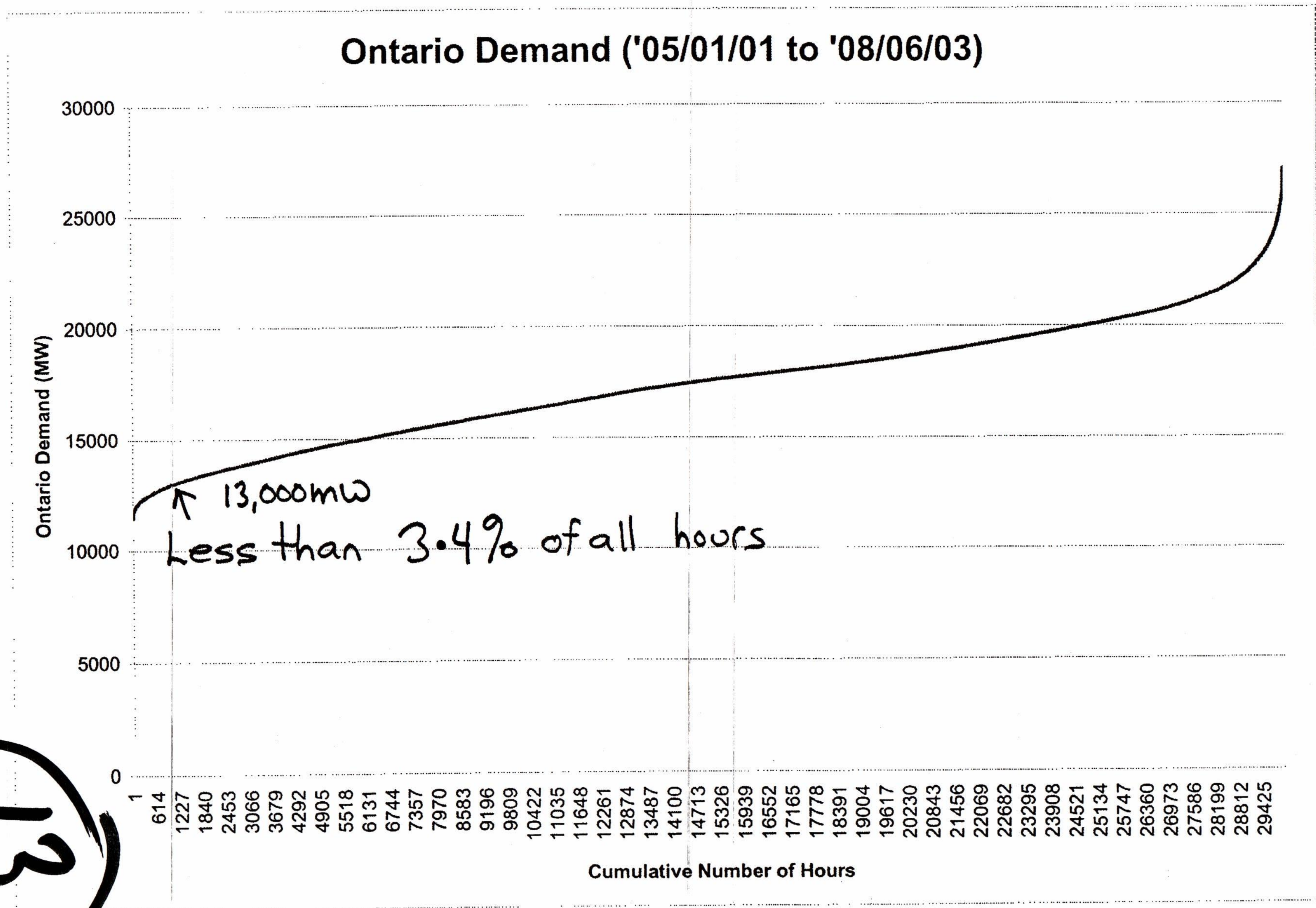
Ontario Demand ('05/01/01 to '08/06/03)
Ontario Demand (MW)
30000
25000
20000
15000
10000
5000
0
1
614
1227
1840
2453
3066
3679
4292
4905
5518
6131
6744
7357
7970
8583
9196
9809
10422
11035
11648
12261
12874
13487
14100
14713
15326
15939
16552
17165
17778
18391
19004
19617
20230
20843
21456
22069
22682
23295
23908
24521
25134
25747
26360
26973
27586
28199
28812
29425
Cumulative Number of Hours
13,000mw
Less than 3.4% of all hours

18-MONTH OUTLOOK:

An Assessment of the Reliability of the Ontario Electricity System

From April 2008 to September 2009

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ieso
Power to Ontario. On Demand.

IESO_REP_0472v2.0 | **Public** | April 1, 2008

Table 5.2 Committed and Contracted Generation Resources

Proponent/Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered in Resource Scenario (MW)	
					FRS	PRS
Durham College District Energy Project	Toronto	Gas	2008-Q1	Construction	2	2
Great Northern Tri-Gen Facility	West	Gas	2008-Q2 (1)	Commissioning	12	12
Countryside London Cogeneration Facility	West	Gas	2008-Q2	Construction	12	12
Portlands Energy Centre Phase I	Toronto	Gas	2008-Q2	Construction	250	250
Warden Energy Centre	Toronto	Gas	2008-Q2	Construction	5	5
Umbata Falls Hydroelectric Project	Northwest	Water	2008-Q2	Construction	23	23
Lac Seul Project - English River	Northwest	Water	2008-Q3 (1)	Construction		13
Greenfield Energy Centre	West	Gas	2008-Q4	Construction		1,005
Kruger Energy Port Alma Wind Power Project	West	Wind	2008-Q4	Construction		101
Wolfe Island Wind Project	East	Wind	2008-Q4	Approvals & Permits		198
Nuclear Upgrade	N/A	Uranium	2008-Q4	Construction	27	27
Melancthon II Wind Project	Southwest	Wind	2008-Q4	Construction		132
Enbridge Ontario Wind Power Project	Southwest	Wind	2008-Q4	Construction		200
Retirement of Lower Sturgeon 25 Hz generation to convert to 60 Hz	Northeast	Water	2009-Q1	Connection Assessment	-5	-5
St. Clair Energy Centre	West	Gas	2009-Q1	Construction		570
Return of Unit 7 at Beck 1 as a 60 Hz unit	Niagara	Water	2009-Q1	Construction	59	59
Retirement of Sandy Falls 25 Hz generation to convert to 60 Hz	Northeast	Water	2009-Q2	Connection Assessment	-3	-3
Goreway Station	Toronto	Gas	2009-Q2 (1)	Construction		860
Retirement of the 25 Hz Frequency Changer and Units 1 & 2 at Beck 1	Niagara	Water	2009-Q2	Connection Assessment	-50	-50
Algoma Energy Cogeneration Facility	Northeast	Industrial Gas	2009-Q2	Construction		63
Portlands Energy Centre Phase II	Toronto	Gas	2009-Q2	Construction		288
Bruce Unit 2	Bruce	Uranium	2009-Q2	Construction		750
East Windsor Cogeneration Centre	West	Gas	2009-Q2	Construction		84
Total					331	4,594

1031 MW

Notes to Table 5.2:

Bruce 750 MW

631 MW new wind

The total may not add up due to rounding.

(1). The estimated effective quarter and/or the year for the project has changed from the last Outlook.

Project status provides a general indication of the project progress. The standard milestones used are: Connection Assessment, Approvals & Permits, Construction, and Commissioning.

- "Connection Assessment" indicates that the project is undergoing a system impact assessment with the IESO.
- "Approvals & Permits" indicates that the project proponent is in the process of acquiring major approvals and permits required to start construction (e.g. environmental assessment, municipal approvals etc). "Construction" means that the project is under construction,
- "Commissioning" indicates that the project is undergoing commissioning tests with the IESO.

Connection Assessment may run concurrently with the other three milestones which are sequential.

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AMPCO Cross-Examination Exhibit

OPG's Baseload Sales Security

	Capacity (MW)	notes	Reference
Minimum Ontario Demand	13,000	Demand exceeded 13 GW 96.6% of the hours since Jan. 2005	IESO Market Data/Hourly Demand
Bruce Power	3,995	4700 MW * 85% Cap. Factor (assumes no outage management)	Bruce Power 2007 Year in Review
Existing Wind	188	470 MW * two times 20% OPA's wind capacity credit	IPSP D/5/1 Attachment 4
New Wind	253	632 MW * two times 20% OPA's wind capacity credit	IESO 18 Month Outlook: April '08 - Sept. '09
Bruce 2	638	750 MW * 85% Capacity factor	IESO 18 Month Outlook: April '08 - Sept. '09
Available market for OPG	**7,927**		
OPG Nuclear Output	5,148	6600 MW * 78% Cap. Factor ('06/'07 avg., no outage man.)	
OPG Reg. Hydro Off-peak	1,900		
Residual base demand	**879**		

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ability to recover its actual costs as a result of access to the existing deferral accounts does not result in a reduction in its risk relative to that of other utilities.

On balance, I view the regulatory risk for OPG as higher than that of the typical regulated utility in Canada and in Ontario. As the Board suggested in its November 20, 2006 report, the application of cost of service regulation to generation is a relatively unique phenomenon, with no track record upon which to gauge the outcome. The uncertainty of the "end state" is amplified by the fact that OPG will be regulated in a market environment which is a hybrid of regulation and competition, which creates additional pressure on regulated rates in a period of potentially significant cost increases (e.g., decommissioning costs, other post-retirement benefit expenses).

Further, OPG potentially faces significant capital expenditures for regulated facilities for which it may require regular access to debt markets. The requirement to refurbish existing nuclear plants, or build new nuclear or large scale hydroelectric generation facilities would entail an extended period between development, construction and putting those assets into service.

In this regard, traditional utility practice has been to exclude assets from rate base until they are used and useful and to accrue an Allowance for Funds Used During Construction (AFUDC) to recognize the financing costs incurred while the assets are being constructed. The AFUDC is capitalized and added to the cost of the assets and recovered after the assets are placed into service.[65] The exclusion of Construction Work in Progress (CWIP) from rate base is potentially a major disincentive to utilities to undertake the construction of major projects.[66] Allowing

[65] Depending on the jurisdiction, the AFUDC rate may be an interest rate or the weighted average cost of capital. In Ontario, while the OEB has previously recognized that it is appropriate to use a weighted average cost of capital (WACC) for purposes of calculating AFUDC, it has recently approved the use of a medium term interest rate to be applied to Construction Work in Progress for distribution utilities. The implication of this decision is that CWIP is 100% debt financed, a conclusion that should be taken into account in determining the allowed capital structure for rate base to ensure that the capital structure underpinning the totality of regulated assets, inclusive of CWIP, contains a reasonable balance of debt and equity.

[66] Recognition of the need to provide incentives to utilities to build needed infrastructure has led the Federal Energy Regulatory Commission to adopt a slate of incentives for transmission utilities that includes allowing CWIP in rate base.

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structure, or allowing returns that do not conform to informed investors' perception of risk. Alternatively, regulation can provide an environment characterized by even-handedness, conducive to continued growth consistent with economic allocation of resources, and affording the utility a reasonable opportunity to achieve a fair return. Enlightened regulation will mitigate risks that are not susceptible to managerial control, and award a return that provides both (1) fair compensation for the risks that are left with management and (2) incentives to achieve (and exceed) the allowed return through continued improvement in productivity. The regulatory framework in which a utility operates is frequently viewed as the most significant aspect of risk to which investors in a utility are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

While OPG has been subject to the provisions of Regulation 53/05 since April 2005, the introduction of active regulation by the OEB as of April 1, 2008 creates a number of uncertainties, as the "end state" of regulation is unknown. The November 30, 2006 "*Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*" ultimately envisions an incentive regulation framework, but the parameters of that framework have yet to be developed, and the information necessary to create that framework can be expected to take a number of years to develop. In the interim, OPG's regulated operations will be subject to cost of service regulation. For purposes of the business risk assessment, I proceed on the assumption that OPG will be treated no differently from any other utility subject to the Board's jurisdiction: OPG will be provided a reasonable opportunity to recover its prudently incurred costs and earn a return that reasonably reflects the risks to which it is exposed.

In that context, certain requirements set out in Regulation 53/05 should be viewed as an implementation of the traditional regulatory prohibition against retroactive ratemaking. Those requirements include that:

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CWIP in rate base in a period of high capital expenditures related to a fundamentally risky generation plant would help mitigate the increase in risks. The inclusion of CWIP in rate base would be viewed as mitigating risk by both debt and equity investors. My recommendation is premised on OPG being allowed to include in rate base CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, such as the Niagara Tunnel. Since OPG is not applying to include CWIP in rate base at this time, the size and duration of generation-related capital projects expose it to higher forecasting and regulatory risks than other OEB regulated utilities.

With the electricity market environment still in flux, the regulated operations of OPG remain subject to political risk. Since the initial restructuring that began in 1998 with the Energy Competition Act, there have been several interventions by the government into the operation of the electricity market. Ontario is one of the two provinces in Canada in which political intervention in the regulatory process has been a factor in the business risk assessment of utilities by the debt rating agencies (Alberta is the other). Political intervention in the industry restructuring process to shield customers from the impact of rising market prices for power was the principal reason given by the debt rating agencies for their downgrades to the debt ratings in 2003 of Ontario electric utilities. The debt rating agencies view the risk of further political intervention in the Ontario market as having declined since those debt rating reductions occurred in 2003. Nevertheless, the risk of future political intervention in the market is higher than in other Canadian jurisdictions, as there continue to be unresolved issues in an evolving Ontario electricity marketplace. With rising energy prices, the potential for future political intervention cannot be disregarded, as recent experience in the U.S. (e.g., Maryland, Illinois) demonstrates.

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CCC and VECC Interrogatory #41

Ref: Ex. C2-T1-S1, page 183

Issue Number:
Issue:

Interrogatory

a) Please estimate and explain the financial flexibility adjustment (add on to the bare-bones estimate) required to target the median market to book ratio of the Canadian utility sample used by Ms. McShane.

b) Please explain in full why any financial flexibility adjustment is needed when
   a. The equity in OPG has been raised by utility ratepayers as retained earnings and not contributed from the equity market?
   b. OPG is owned by the Province of Ontario and has no publicly issued equity so there can not be a "market break" or decline in the stock price when equity is issued to raise capital to serve?

Response

a) Ms. McShane has estimated the financial flexibility adjustment based on the average market value capital structure of the Canadian sample as presented in Ex. C2-T1-S1, Schedule 22, page 246 – 247. The results are summarized on page 184; the calculations are provided in Ex. C2-T1-S1, Schedule 22, page 246 – 247. The cost of equity derived using CAPM or DCF is a market-based estimate. It is estimated in relation to market value capital structures. As indicated on page 183, if that cost of equity is applied, without adjustment, to a book value capital structure with less equity than the market capital structures, the lack of adjustment to the cost of equity "fails to recognize the higher financial risk and the higher cost of equity implied by the book value capital structure."

The results in Ex. C2-T1-S1, Schedule 22, page 246 – 247 show that recognition of the difference in financial risk between the average market value (53% common equity) and book value (39% common equity) capital structures of the publicly-traded Canadian utilities results in an increase in the cost of equity in the range of 105-205 percentage points. Based on the median market value capital structure of 55% common equity, the required increase in the cost of equity would be in the range of 1.2-2.4 percentage points. These results (in conjunction with those for the U.S. low risk utility sample (Ex. C2-T1-S1, Schedule 23, page 248 – 249) demonstrate that a financing flexibility adjustment of 50 basis points represents a minimum.

b) Ms. McShane has discussed the need for a financing flexibility adjustment for OPG in detail in Ex. C2-T1-S1, Appendix G, page 181. See also response to L-1-6. Ms. McShane disagrees with the premise that the equity in OPG has been raised by ratepayers. Ratepayers pay for service, including a return on the capital devoted to service delivery; in general, they do not acquire an ownership position in the company. The equity, including the retained earnings, is owned by the shareholder, who can extract it in the form of dividends to be used for purposes other than electricity related services or reinvest it in generation assets. Retained earnings in OPG have been no more raised by ratepayers than the retained earnings in Enbridge Gas have been raised by its ratepayers or the retained earnings in Tim Horton's have been raised by the customers who purchase doughnuts and coffee.

Only going forward
↓
Stranded debt treatment was opposite
↓
retained losses shifted to ratepayers

CCC and VECC Interrogatory #11

Ref: Ex. C2-T1-S1, page 23

Issue Number:
Issue:

Interrogatory

Risk Free rate

a) Please provide the most recent copy of the Consensus Economics interest rate forecast and Ms. McShane's estimate of the 30 year Canada bond yield.
b) Given the weakness of the US economy and the dramatic decline in US short term interest rates please provide a justification for why interest rates would increase at this stage of the business cycle.

Response

a) The March 2008 Consensus Economics *Consensus Forecasts* is attached as "L-3-11 Consensus Forecasts March 2008.pdf". Ms. McShane's estimate of the 30 year Canada bond yield for the remainder of 2008 and 2009, based on the most recently available forecasts, is 4.5%.

b) The forecast is premised on the expectation of moderate growth in the U.S. economy beginning in the second half of 2008, gathering strength to levels consistent with long-term trend growth (2.5-2.7%) in the second and third quarters of 2009. (Blue Chip *Economic Indicators,* April 1, 2008)

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AMPCO: Market Risk Premium Results from Prefiled Evidence

	Stock Return	Bond Return	Risk Premium
Foster			
1947 - 2006			
Canada			
Arithmetic mean	12.4	7.0	5.5
Geometric mean	11.2	6.5	4.7
Booth			
1924 - 2007			
Canada			
Arithmetic mean	11.8	6.5	5.3
Geometric mean	10.3	6.1	4.2
OLS	10.4	5.6	4.8
1957 – 2007			
Canada			
Arithmetic mean	11.1	8.0	3.1
Geometric mean	9.9	7.5	2.4
OLS	10.4	8.6	1.8
Kryzanowski and Roberts			
1926-2007			
Canada			
Arithmetic mean	11.6	6.5	5.1
Geometric mean	10.1	6.1	4.0
1957-2007			
Canada			
Arithmetic mean	11.1	8.0	3.1
Geometric mean	9.9	7.5	2.4

Sources:
Foster: C2-1-1 Schedule 3, page 217;
Booth: Exhibit M-Tab3, Appendix E. Schedules 1 and 6; and
K&R: Exhibit M – Tab 12, Schedule 4.3, page 211