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ONE Nicholas Street, Suite 1204, Ottawa, Ontario, Canada K1N 7B7
Tel: (613) 562-4002 ext. 26 Fax: (613) 562-0007. e-mail: mjanigan@piac.ca. http://www.piac.ca

August 26, 2014

Via Email – 36 pages

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB 2013-0321 OPG 2014-15 Payments Amounts Application
Argument of the Vulnerable Energy Consumers Coalition (VECC)

On behalf of the Vulnerable Energy Consumers Coalition (VECC) we have attached their Argument e: the above-noted proceeding. We have also directed a copy of the same to the Applicant and their counsel as well as all interested parties.

Yours truly,

Michael Janigan
Counsel for VECC

cc:
OPG – Colin Anderson – opgregaffairs@opg.com
OPG – Carlton Mathias – opgregaffairs@opg.com
Counsel – Charles Keizer – ckeizer@torys.com

EB-2013-0321

IN THE MATTER OF the *Ontario Energy Board Act 1998,* S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application filed by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act 1998* for an order or orders determining Payment amounts for the output of certain of its generating Facilities

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ARGUMENT OF THE
VULNERABLE ENERGY CONSUMERS COALITION
("VECC")

August 26, 2014

Introduction

As numerous intervenors have pointed out, the size of the increase in payments sought by OPG in this hearing has made it consequential for all ratepayers in Ontario. The projected impact upon residential households of over $63 a year makes it imperative that the adjudication of the issues in this proceeding results in a funding envelope that encourages an approach to operational efficiency that is ultimately reflected in its filings in future proceedings.

Currently, we have to be cognizant of the criticism of OPG's planning and operations that has emanated from such sources as the Auditor General of Ontario. At a time when ratepayers are bearing heavy burdens form other aspects of energy regulation to meet long term planning needs; VECC was very concerned about the added weight of possibly unnecessary expenditures in rates.

On the other hand the ambitious and expensive plans of OPG attracted a large number of participating intervenors that shared the same concerns in their own constituencies. VECC was careful to be non-duplicative of supportive work done by other and Board Staff, and to be cooperative in relation to the goal of eliciting information that was pertinent to the decisions that must be made by the Board on the OPG application.

As a consequence, VECC's intervention has been targeted and focused on a constellation of issues of concern to its constituency in which they have expertise and familiarity. On other issues in this proceeding, it has relied on the work of other intervenors to advance ratepayer interests. Much of that work has received support in this Argument. VECC believes that this is in keeping with the objectives of the Board, and is grateful for the assistance of other intervenors in circulating their draft argument in advance of its submission.

SUBMISSIONS ON ISSUES

1. GENERAL ISSUES

1.3 Secondary - Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

VECC has reviewed the submissions of Board Staff and supports those submissions in respect of this issue.

ISSUE 3 CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Primary - What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

3.2 Secondary - Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

As the Board noted in its 2009 Cost of Capital Report (EB -2009-0084)

> ***Fair Return Standard.*** *All three requirements – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others. It is not sufficient for a formulaic approach for determining ROE to produce a numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE; it must generate a number that meets the FRS, as determined by the Board using its experience and informed judgment*

The expert witness for OPG, Ms. McShane, agreed with the Board's statement and that the FRS requires that the fair ROE be applied to the appropriate common equity ratio: that it is the end result of both the allowed ROE and the common equity ratio that meets the Fair return standard.

In terms of the ROE, OPG intends to apply the OEB formula for 2014 that results in a 9.36% ROE (Tr. Vol. 10 page 18)[1]. This ROE is a generic ROE that normally applies to all utilities under the Board's regulation, where differences in business risk are reflected in different common equity ratios as noted by Ms. McShane (Vol. 10 Transcript page 29, line 8). In cross examination, Ms. McShane was given a copy of a recent summary of allowed ROEs and common equity ratios prepared by Concentric Energy Advisors on behalf of the Canadian Gas Association. The median ROE and common equity ratio for Canadian electric distributors in 2014 was an 8.75% ROE on 40% common equity.[2]

The Concentric Energy Partners document indicates that the ROE requested by OPG is at the very top of the range for a benchmark allowed ROE. What is also relevant is that apart from the OEB allowed ROE, which was set by formula in 2009, these allowed ROEs were set by normal hearings. Indeed, the most recent decision by a Canadian regulator, the Regie in Quebec, allows Hydro Quebec Distribution 8.20% ROE on 35% common equity and Hydro Quebec Transmission 8.20% ROE on 30% common equity. As Ms. McShane acknowledged these financial parameters were set by the Regie on a stand-alone basis.

There is no question that at the current point in time the benchmark allowed ROE flowing from the OEB formula results in a significantly higher allowed ROE than currently being awarded by other Canadian regulators to benchmark utilities. So what is clear is that the first part of the fair return standard, the allowed ROE, is generous to say the least.

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[1] All transcript references refer to Volume 10, dated June 26, 2014.

[2] For the four Alberta utilities the current allowed ROE of 8.75% may be changed as a result of a generic AUC hearing that concluded in June 2014. However, deleting these four does not change the median ROE.

What is more as a cross aid Ms. McShane was given a copy of the transcript of parts of her cross examination before the BCUC (ExK-10.2, p.12) In that hearing, she admitted (Transcript Volume 3, page 401) that her risk ranking of utilities had not changed as she didn't think that there's "anything in the different sectors that's changed materially. Let's say in the last 10 years." Furthermore in answer to counsel, Mr. Wallace, she agreed that in terms of fundamental business risk with the ranking in terms of increasing risk: AltaLink, Newfoundland Power, FEI, Fortis BC, and then Nova Scotia Power Inc., (NSPI). Of importance is that the last two are the only major utilities apart from OPG that have generating assets.

Ms. McShane was then cross examined on these last two utilities. The reason being that Fortis BC is allowed a premium to the benchmark ROE by the BCUC of 9.25% on 40% common equity, whereas NSPI negotiated a 9.0% ROE on 37.5% common equity. In the case of Fortis BC generation is only 17% of rate base but for NSPI it is 60% (transcript, page 26).

The reason for going through these comparators is to place OPG in the spectrum of Canadian utilities, similar to what was done in 2008 when the Board, inter alia, considered the issue of the appropriate equity thickness for OPG in proceedings culminating in the EB 2007-0905 Decision. In that Decision, the Board considered expert opinion and submissions offered by OPG and interested stakeholders on the subject of risk. In doing so, the Board rejected OPG's contention that OPG's regulated assets bear a higher political risk than other Ontario regulated utilities because of government ownership[3] as well as its contention that OPG was exposed to higher regulatory risk because it is new to Board regulation.

[3] EB -2007-0905 Decision with Reasons,p.141-143. The Board also rejected the notion that government ownership reduced risk.

The Board was thus left to decide OPG's business risk, and hence the appropriate common equity or the level of equity thickness, based on the nature and risks associated with the business operations of OPG, namely hydro and nuclear generation. The expert witnesses in that proceeding attempted to analyse the business risk of each OPG business area with a view to making a recommendation on the overall OPG common equity ratio.

OPG's expert witness in the EB 2007-0905 case was the same Ms. McShane who presented evidence in this hearing. At that time, she recommended a common equity ratio of 57.5% for OPG, which the Board rejected. It is worthwhile remembering why the Board rejected Ms. McShane's recommendations. As the Board noted:

> "The Board finds that the proposed equity ratio of 57.5% is excessive. The incremental level of risk does not warrant the additional 12.5% equity over that of the next highest regulated utility. It is also well in excess of the equity levels of merchant generators, who have higher risk than OPG, as pointed out by Mr. Goulding. The Board concludes that the recommendation of Drs. Kryzanowski and Roberts, namely an equity ratio of 47%, is appropriate in the circumstances. This ratio is higher than the equity ratio of any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG."[4]

Since the time of this decision we would point out that Ms. McShane recognizes NSPI as the highest risk comparable in Canada with a 9.0% ROE on 37.50% common equity, so OPG is asking for a 0.36% higher ROE and almost 10% higher common equity ratio. At this point it is important to remember that it is the combination of ROE and common equity that matters as Ms. McShane pointed out (Vol. 10Transcript, page 27) when she indicated that 40 basis points in ROE was worth about 4% in common equity; so de facto OPG with a 0.36% higher ROE

[4] Ibid, pp.149,150 The same capital structure was continued in the Board's next review in EB 2010-008

than NSPI is asking for at least a 13% higher common equity ratio. Also Newfoundland Power with a 45% common equity ratio has an 8.80% allowed ROE or 0.56% less than OPG is requesting so, after adjusting for the ROE using Ms. McShane's formula, this means an effective common equity ratio of less than 40% or again at least 10% less than OPG is requesting.

We would suggest that the goal posts have moved since 2008, as allowed ROEs have dropped more for most utilities than in Ontario. When we make the sort of adjustments made by OPG's witness Ms. McShane it is clear that the current request by OPG for 9.36% ROE on 47% common equity is as egregiously high today as its request in 2007 and the Board's assessment at that time still applies today.

Since the Board relied heavily on the expert testimony of Dr. Kryzanowski and Dr. Roberts in its 2008 decision it is worth reminding us of how they arrived at their decision.

Drs. Kryzanowski and Roberts arrived at their overall equity ratio recommendation by examining the weighted average capital structures for hydro and nuclear operations and applied them against the equity ratio estimated for each:

> "Based on these examinations and tests, we arrive at a recommendation for the appropriate equity ratio for each segment of OPG. We assess the business risk faced by OPG Hydro as low to moderate – higher than that of a distribution utility and somewhat above the business risk of an integrated electric utility. This suggests that a fair common equity ratio for OPG Hydro should be at 40%, just below the middle of the range of common equity that we find for our comparisons. In contrast, our analysis rates the business risk of OPG's regulated nuclear assets as moderate and greater than that of OPG Hydro. The higher business risk of OPG Nuclear should translate into a significant increase

in its common equity ratio on the order of 5 to 10% over that for OPG Hydro producing a recommended equity ratio for OPG Nuclear of 45 to 50%. In the interests of conservatism and to ensure fairness to the shareholder, we recommend the higher number of 50% for the equity ratio. In order to achieve an overall recommended capital structure for OPG's rate base we calculate a weighted average of our individual capital structures using the asset breakdown in the Electricity Restructuring Act of Ontario of 2004: 66.47% nuclear and 33.53% hydro. When we apply these weights to our two separate capital structure recommendations, we obtain an overall rounded recommended equity ratio of 47% for OPG's rate base. Thus, our recommended common equity ratio for OPG's total regulated assets is 47%."[5]

What is important is that the recommended 47% common equity ratio accepted by the Board was underpinned by a common equity ratio for hydro of 40% and an equity ratio for nuclear of 45-50%, where for "conservatism" they used the higher number. These ratios were then applied against the proportionate rate base for hydro and nuclear. With NSPI at 37.50%, the 2008 recommendation of Drs. Kryzanowski and Roberts of 40% common equity for hydro remains a slight premium over that for an integrated electric utility while there is no evidence of any change in the business risk of OPG's nuclear assets. This is consistent with Ms. McShane's broad comments before the BCUC that the different regulated sectors have not changed their risk rankings materially in the last ten years.

It remains to consider the most important change since 2008 which is the change in the proportion of hydro versus nuclear assets. This was the basis of the recommendations put forward by Drs. Kryzanowski and Roberts in 2008 and which were adopted by the board. Here it is important to note that in the Board's 2009 (EB -2009-0084) the Board gave guidance with respect to the circumstances

[5] Evidence of Drs. Kryzanowski and Roberts, EB-2007-0905 - OPG - 2008-09 Payments, pp7-8

under which the Board may consider a change to the regulated utility's equity ratio:

> "The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals." [6]

As previously noted, the Board's Report stated that each time a formulaic approach is used to derive an ROE it must arrive at a number that meets the Fair Return Standard requirements of comparable investment, financial, integrity and capital attraction.[7] In 2008 OPG's nuclear assets comprised 66.47% of OPG's rate base. Since then, it has fallen dramatically. In our view the change in the composition of OPG's rate base implies a corresponding lowering of risk, and will violate the Fair Return Standard without Board intervention.

Table 2 shown at Exhibit C1, Tab1, and Schedule 1 shows that the hydro component of OPG will double by 2014 with the addition of another $2.5 billion in new hydro facilities and $ 1.4 billion for the Niagara Tunnel at which time the rate base of OPG is approximately 10 billion. The hydro share increases to about 77% and the nuclear drops to 23%. Using the base estimates approved in EB-2007-0905 of 50% for nuclear and 40 % for hydro, the changed composition of OPG's rate base implies a new common equity ratio of 42.3%. It would be even lower if we did not use the upper end of the nuclear range proposed by Drs. Kryzanowski and Roberts.

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[6] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB -2009-0084, p.49. Subsequent Board Decisions in applications by Union Gas Limited and EGDI have confirmed the necessity for a significant change in risk to alter the equity thickness.

[7] Ibid p.31

While it would appear obvious that the increase in the proportion of hydro assets means a significant downward adjustment in risk, necessitating a reduction in the common equity ratio, OPG's expert witness did not agree. And this was despite the fact that Ms. McShane admits that a one or two per cent change in equity thickness can be material in relation to setting the long-term risks and the long-term needs to access capital.(Vol. 10. Transcript. p. 42)

> MR. JANIGAN: Do you regard a 1 to 3 percent change in the common equity ratio as material?
>
> MS. McSHANE: It can be, yes, particularly when the equity ratio is relatively low.
>
> I mean, if you had a 60 percent equity ratio and you went to 58, probably not that significant, but if you're at 35 and move to 37, then yes.
>
> MR. JANIGAN: All right. I understand that you testified in support of a 2 percent across-the-board increase in common equity ratios for Alberta utilities?
>
> MS. McSHANE: I did.

However, Ms. McShane believes that there should be no such adjustment in this instance. In her evidence and in her cross examination, she advanced the proposition that the equity thickness should not be changed for two reasons: (1) the new hydro assets under regulation have more risk and (2) the refurbished nuclear assets at Darlington will be coming on stream later in the decade.

The source of this additional risk seems to be the non-centralized location of the new plants and the different conditions under which they operate (Transcript page 33):

MR. JANIGAN: Let me go back to the new generation. Why do you regard new generation as riskier when they will be mainly brought on when base load is not enough?

MS. McSHANE: Because of the difference in the operating environment of those plants, as set out in my testimony on page 12.

MR. JANIGAN: And do you summarize that?

MS. McSHANE: Well, they are scattered all over the place. They're small. A number of them are remotely located. They're hard to get to. There are no service centres that are on-site that are staffed. There are strict water-level constraints with some of these plants.

MR. JANIGAN: These plants mainly substitute for coal-base peaking, do they not?

MS. McSHANE: They substitute for coal-based peaking? I don't know that.

This conclusion that the new hydroelectric facilities bear increased risk seems to be out of place with the circumstances of their construction, namely the need for peaking power to replace coal generation and the continued massive investment in nuclear, which is hardly consistent with an environment where the new hydroelectric facilities would be dormant. As well, as Mr. Shepherd, counsel for SEC, explored in his cross-examination of Ms. McShane, her analysis concerning the risk factors associated with the new hydro-electric facilities seemed to be decidedly non-quantitative in nature and based largely on OPG derived information. We would submit that a review of the same should lead the Board to the conclusion that the suggestion of increased risk for these new hydro assets is, at best, highly speculative.

The Darlington refurbishment presents the other major grounds for maintaining the current equity ratio. It seems to create a many faceted constellation of risk factors for Ms. McShane, the chief ones being apparently, the inherent risk of nuclear facilities and the risk that construction expenses may be rejected by the Board as imprudent:

> MR. JANIGAN: Okay. So there would be -- notwithstanding the fact that the assets in hydro have increased from close to 50 percent up to now 77 percent and nuclear have been reduced, we're not going to get any drop in the common equity ratio?
>
> MS. McSHANE: No, because at the same time that we have this change in the proportions of rate base, as I've said a couple of times now, you -- we have an increase in the amount of capital expenditures that are related to nuclear facilities.
>
> Even though they're not in rate base, they're capital expenditures that have to be financed and they're going to be financed by debt. They have to be supported.
>
> As -- the testimony also noted that the size of the refurbishment, in total, is very large. And in fact, you know, as this -- as the refurbishment is brought into rate base, you're going to have a shift, again, in the relative sizes of hydroelectric and nuclear.
>
> And even though those capital expenditures for nuclear are not in the rate base today, the risks are still there and need to be reflected in the capital structure of the overall regulated operations.

Thus, according to Ms. McShane, ratepayers must both accept higher equity levels for the construction of nuclear facilities coming on stream into rate base by the earliest of 2018 and fully by 2024. (Tr. Vol10 pp.43,44), and Darlington's risk impact in advance of generating any electricity being generated because of risk of construction disallowances by the Board. Later Ms. McShane rather perplexingly admits that this is a small factor in the recommendation to retain the 47%. (Tr. Vol.10. p. 45).

We recommend that current rate payers not be charged for assets not yet in rate base. This represents an intergenerational inequity and violates standard regulatory principles. The fact is that current rate payers should only pay for the assets and the risk generated by those assets in the rate base. The undisputed fact here is that in 2008 the rate base was 66.47% nuclear, whereas in 2014 it is projected to be 23%. It is absolutely clear that there has been a decline in OPG's business risk that necessitates a reduction in its allowed common equity ratio. When the nuclear assets are included in rate base, possibly ten years from now, then the rates can be adjusted at that time.

Ms. McShane also revisits an old chestnut of regulatory risk under incentive-based regulation. There is scant evidence of the same. The recent OEB decisions in the Enbridge and Union cases concerning risk disclose no consideration by the Board of any increased risk associated with the onset of PBR. What is important is that the utilities know full well that the Board will only allow more common equity if the utilities demonstrate an increase in business risk. Yet in the Union Gas decision (EB-2012-1015, page 48) the Board noted

> *Union filed no evidence in this proceeding that demonstrates its business and/or financial risks have changed over the period that the IRM Settlement Agreement was in place. In fact, Union*

> *stated many times during the proceeding that its business and financial risks have not changed and that it accepts that its overall risk profile has not materially changed since 2006.*

Further in its Enbridge Gas distribution Decision (EB-2013-207, page 18) the Board stated

> *The Board concludes that there has been no significant increase in Enbridge's business and/or financial risk since 2007. Accordingly, the Board finds that Enbridge's equity ratio shall remain at 36% and that a full FRS analysis is not required.*

It is quite clear that the two major utilities that operate in Ontario under incentive rate making see no increase in their business risks, perhaps because they have significantly over-earned as a result.

As well other utilities have shown no difficulty in earning their allowed rate of return (Vol. 10Transcript, page 52):

> MR. JANIGAN: Are you aware that both Gaz Métro and FEI B.C. Gas have been on PBR for almost a decade?
>
> MS. McSHANE: Gaz Métro has been on a form of performance-based regulation. And re you talking about Fortis B.C. Energy Inc., the gas distributor?
>
> MR. JANIGAN: Yes, that's correct.
>
> MS. McSHANE: It also had been on incentive-based regulation for a number of years.

> MR. JANIGAN: Is there any evidence that they have suffered any risk in the dictionary sense of incurring harm, have consistently overearned their allowed ROE on PBR?
>
> MS. McSHANE: I think, on average, they have earned higher than their allowed return, which of course is what PBR is designed to incent companies to do.

While Ms. McShane contends there has been increased risk from PBR, the best predictor in this case is the past results, which has shown consistent levels of more than satisfactory performance by regulated utilizes under PBR. Finally on this topic we can't finish without noting the weakness of the evidence put forward by Ms. McShane as evidence of increasing PBR risk. In support, she references a paper by Camacho and Menezes and despite her subsequent retraction of her putting any weight on the paper (Vol. 10, Transcript, page 56). The paper's conclusions demonstrate its irrelevance clearly as it states:

> *"We have investigated the relationship between price regulation and the cost of capital in a two-period model in which the regulator faces moral hazard and an entrepreneur is capital constrained. In our model, the cost of debt is greater than or equal to the cost of equity. Thus, the entrepreneur chooses the minimum level of debt possible."*

We respectfully submit that there OPG is not an entrepreneur financed utility, that is does not have any capital constraints, but the idea that Ms. McShane would put any weight at all on a paper based on a model where the cost of debt is greater than the cost of equity is, to say the least, intriguing.

We judge the centerpiece of Ms. McShane's argument to be the construction of nuclear facilities and not the business risk associated with the facilities, as they will not be fully in rate base until 2024. As to her submission that the Board must contemplate future developments in the business risk assessment in the current common equity ratio, there is Board decision language directly on point. As the Board noted in EB 2011-0354 in its Decision on page 7:

> "Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."

Ultimately, Ms. McShane's argument for the retention of a 47% common equity, despite clearly changed operational circumstances, fails for more than the weakness of her two hypotheses regarding the new hydroelectric facilities and the oncoming Darlington capital additions. The critical problem with Ms. McShane's insistence on retention of the 47% equity ratio is that it trades the observable and accepted for the theoretical; the effect of which is highly debatable and unconfirmed. Ms. McShane's conclusion stretches the analytical envelope suggested by Drs. Kryzanowski and Roberts to the point of irrelevance (Vol. 10, Transcript, page 40)

> MR. JANIGAN: Let's say, in a hypothetical case, that the hydro generation assets went to 95 percent and nuclear was at 5 percent. Would we see any decrease in the common equity ratio?
>
> MS. McSHANE: Probably very little. I mean, if we -- we might see a little bit, but I mean it's -- it would be marginal.

The end result of Ms. McShane's analysis is a regulated utility with the highest ROE and the highest equity ratio of any in Canada (Transcript, pages 29-30). In addition, it would make OPG seemingly impervious to any lowering of risk and common equity ratio even when the composition of its assets substantially changes.

VECC would submit that the there is little reason to depart from the use of the framework for equity thickness for OPG derived in the EB 2007-0905 Decision. In light of the new proportion of nuclear versus hydro-electric assets the equity ratio should be reduced to no more than 42.5%.

Capital Structure - CME position

VECC has had the advantage of reviewing the draft argument of CME on the issue of the effect of the addition of previously unregulated assets to the OPG rate base. CME quite rightly notes that determining the revenue requirement for cost of capital requires the regulator to consider the actual source of funding for the same. To do that, CME states that the regulator must look to the cost of capital supporting those assets just prior to the effective date of their re-characterization or re-classification as prescribed or regulated OPG assets. No new capital was expended to support the re-characterization of the assets to owner equity capital

In VECC's view, CME's thesis correctly states the appropriate treatment for these assets. While the recovery of an ROE from taxpayer financed assets has been a policy/political exception to regulatory principles, the Board in the past has refused to be indiscriminate in the consideration of assets financed in other ways as part of equity capital. One example is the Board's refusal to treat assets funded by deferred taxes as equity capital.

As a consequence, the CME proposal is to treat the newly regulated assets as unstranded debt subject to the same cost of capital as stranded debt makes sense form an historical perspective. As well as CME notes that there is nothing in the

Government's proposal to prescribe OPG's unregulated non-contractual hydroelectric assets as utility assets which gives the right to OPG to recover more than the costs of the capital actually supporting those assets.

VECC supports the CME proposal. In the event that it is not accepted by the Board, VECC urges that its submission as to the resulting lowering of the equity ratio to 42.5% be adopted taking into consideration the changed ratio of hydro and nuclear assets from the Board's first review of the issue in 2008.

ISSUE 4 CAPITAL PROJECTS

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.2 Secondary - Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

4.3 Secondary - Are the proposed test period in-service additions for regulated hydroelectric projects (excluding the Niagara Tunnel Project) appropriate?

VECC has reviewed the submissions of Board Staff with respect to Issues 4.2 and 4.3 and supports those submissions.

Regulated Hydroelectric

4.4 Primary - Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

4.5 Primary - Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

With respect to the Niagara Tunnel Project, VECC notes that had the definition phase costs not been written off by OPG's predecessor company, Ontario Hydro, the actual recovery sought by OPG from ratepayers would have been even more than the amount currently being sought.[8] That is to say, the cost control debacle that is described in the evidence in this hearing understates the extent of the actual cost control debacle.

VECC further notes that while ratepayers are responsible for the total mitigation costs incurred by OPG, OPG was unable to provide (i) the ratepayer savings by Strabag writing off some costs or (ii) the ratepayer savings due to OPG's mitigating activities.[9] VECC submits that while ratepayers were responsible for the costs of mitigation, there is no evidence that ratepayers benefitted from the mitigation.

Additionally, with respect to the insurance claim filed by the Owner's Representative on behalf of OPG in the amount of $17.6M, OPG is seeking recovery from ratepayers for the full amount of the $7.6M disallowed by the insurance adjuster.[10] In VECC's view, this amounts to ratepayers underwriting project costs that the insurer refused to cover, bringing into question the appropriateness of OPG seeking recovery from ratepayers of monies disallowed by the adjuster.

That said, VECC has reviewed the very comprehensive draft submissions of AMPCO in respect of the Niagara Tunnel Project and adopts those submissions on this issue.

ISSUE 4 CAPITAL PROJECTS

Nuclear

4.8 Primary (reprioritized) - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

VECC has reviewed the submissions of Board Staff with respect to Issue 4.8 and supports those submissions.

[8] Transcript Volume 2, page 104
[9] Ibid, page 105
[10] Ibid page 106

ISSUE 4 CAPITAL PROJECTS

Nuclear

4.9 Primary - Are the proposed test period in-service additions for the Darlington Refurbishment Project) appropriate?

4.10 Primary - Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?

4.11 Oral Hearing: Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

4.12 Primary - Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

6.7 Primary - Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Project appropriate?

Darlington Refurbishment Project Overview

There appears to be a kind of disconnect between the self -image of OPG and marketplace reality as reflected in OPG's rejection of the necessity to show that its historical operating patterns including gigantic cost overruns and continued requirements for refits are not the best prediction of the future. This proceeding is not charged with determining the future of Darlington or whether ongoing capital expenditures are capable of generating the hoped for long run energy future. We must note that this company has incurred cost overruns of 4.5 times over budget for Darlington alone. It has brought forward these ambitious plans as part of a package that will result in a 23.4% increases in fees that will be absorbed by Ontario ratepayers such that the average residential customer will see a yearly increase of over $63 [11]. As well, OPG estimates of expenditures have hardly been accurate. OPG's Argument in Chief (AIC) even inflates the substantial pre-filed capital expenditures required for 2014 and 2015 respectively to 839.9M and 842.5 M arising from 2013 Actuals of 232.5 M.

[11] OPG Written Argument in Chief, July 28, 2014, p. 2.

Ratepayers cannot afford, nor should they be required to be the shock absorbers for OPG's budget and operational mistakes. Nor should regulatory principles such as the limitation of rate base items to those assets actually used and useful be ignored in the latest efforts to revive its nuclear fortunes. What is called upon is a fair but critical regulatory approach that rewards success not just unforeseen failure. VECC supports the approach urged by CME of strict adherence to regulatory principles and disallowance of expenditures that fall below the prudency standard.

Test Period Capital Expenditures

VECC has had the opportunity to peruse the Board Staff Submission with respect to the level of inexactitude that accompanies this part of its evidence as it is difficult to ascertain which set of capital expenditures that OPG seeks a finding of reasonableness. VECC concurs with the position that, as many of the projects will not be in service, they should be subject to a prudence review before they are closed to rate base. This has been said to be congruent with a release quality cost estimate[12] in that the Board would then establish a framework to adjudicate prudency.

Clearly one part of any exercise in that regard is the use of estimates following the AACE Guidelines that give realistic probabilities ofa particular result and are accordingly incorporated into the Board's contemplated review.

In Service Additions

It is to be noted that most of the construction of in service additions concern the construction of a heavy water storage facility (the "D2O Project") and the auxiliary heating system (the "AHS"). According to the the BMcD/Modus report , these are two projects that "may cause external stakeholders to question management prudence."[13]While the description of the problems caused largely by managerial failings seems to make questionable any recovery of additional costs for these two projects, OPG insists that the additional costs of $260M have added value and as such should be passed on to ratepayers through their addition to rate base.

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[12] See EB 2010-0008 Decsion p.72

[13] BMcD/Modus Report, May 13, 2014 at p.10.

Board Staff suggest a remedy of excluding a finding of prudence even if they are added to rate base. These are not insignificant costs. VECC submits that the Board should order that the OPG obtain an independent expert report that addresses what costs were incurred to remedy the managerial errors identified in the BMcD/Modus along with the costs of the original mistakes. Any additional value brought about by fixes can also be evaluated. Until such a report is accomplished and presented to the Board in a proceeding to determine the same the entire amount of the in service projects and the remedial expenditures should be excluded from rate base.

OPG's Commercial and Contracting Strategy

OPG's contracting strategy that effectively places most of the risk of cost overruns on The Company and ultimately electricity has come under scrutiny in this proceeding. Board Staff has cautioned against too far a migration into areas that are looked upon as the province of management. However, OPG is asking for a finding of reasonableness in respect certain "guiding principles" forming the commercial strategy selected by OPG for the DRP. These strategies include the use of a multi-prime contractor model where OPG remains responsible for the entire project and the use of target pricing where more oversight is needed

Board Staff has argued against the blessing of this contraction strategy and any finding should not be for prudence of the project. However, in an environment where nuclear projects have gone 2.5 times over budget, it is worthy question to ask why only 7% of OPG's outside contracts are fixed price contracts.[14] The result, as Environmental Defense notes, is to effectively do the very thing that the Long Term Energy Plan urges against, namely increase risk for the ratepayer. It also opens the door for more cosy relationships with external contractors particularly when as ED's argument points out there are a number of ways contracts that feature targets can gamed.

VECC submits that efforts to obtain fixed price or turnkey contracts should be documented and the efforts be in good faith prior to the Board's acceptance of external contracts particularly in the nuclear business.

[14] 16 Hearing Transcript, July 17, 2014 (Vol. 15), p. 56 - 57 [Compendium tab 2]; Contracting Strategy for Retube and Feeder Replacement (Ex. D2-2-1, Attachment 6-2), p. 8, 14 [Compendium tab 3].

Alignment with Ontario's Long Term Energy Plan

Apart from our observations concerning risk and its seeming amplification by OPG's contracting strategy, VECC has no submissions on this issue, primarily because it is the execution of its plan that poses the greatest challenges for OPG to meet the goals of the Long Term Energy Plan

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.4 Primary - Is the proposed new incentive mechanism appropriate?

9.8 Secondary - Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

The Currently Approved HIM

OPG currently has regulatory approval of a Hydroelectric Incentive Mechanism (HIM) the purpose of which is to incent the utility to time-shift production from periods when price is low to periods when price is high.

A high-level description as to how the currently approved HIM generates HIM revenues operationally was provided on the record:[15]

> MR. MILLAR: …Currently you have what's called a hydroelectric incentive mechanism, or HIM; is that correct?
>
> MR. WILBUR: That's correct.
>
> MR. MILLAR: I guess the way that that works is -- and you can correct me if I am wrong -- in cases where you are able to produce more power than your monthly average hourly production, you can sell that excess production

[15] Transcript Volume 4, June 17, 2014, pp 15-16

for the market price instead of the payment amount; is that the high-level way it works?

MR. WILBUR: That's correct.

MR. MILLAR: And I guess for the previously regulated, generally the way you would operationalize that is you would store water at the pump generating station when demand and prices were low, you would pump the water, and then you would release that water during high-price times. Is that generally how you made it work?

MR. WILBUR: Correct. Just the other half of the way you described how the incentive mechanism works, when we operate the unit, the hourly production is below the monthly average, then we are buying back the difference from the market, and so assuming we are doing that, we are buying it back at a lower price than what we are selling, in essence.

MR. MILLAR: Exactly. And the reason that the Board approved that, that that's in the public interest, is because actually overall it creates savings for ratepayers; is that right?

MR. WILBUR: That is correct.

MR. MILLAR: Because you are avoiding other higher cost-generating options at those peak hours.

The currently approved HIM provides for a 50:50 sharing of the HIM revenues between ratepayers and OPG by embedding a first tranche of expected HIM revenues as an offset to the revenue requirement[16] (i.e., a ratepayer credit),

[16] For 2013, the embedded offset is $6.5M. The second tranche for OPG is $6.5M for a total of $13M per E1.2.1 page 5.

allocating a second tranche of expected HIM revenues equal in amount to OPG, and splitting any HIM revenues received in excess of the total of these two tranches equally between ratepayers and OPG.[17]

Surplus Baseload Generation (SBG)[18]

Spills can occur at OPG's hydroelectric for a number of reasons other than SBG[19] and OPG's evidence is that it can calculate the amount of spills due to causes other than SBG and, by subtracting these amounts from total spill at each facility, derive the spill related to SBG.[20]

In its EB-2010-0008 Decision, the OEB approved the creation of the Surplus Baseload Generation Variance Account (SBG VA) "to capture the financial impacts of foregone production at OPG's hydroelectric facilities due to SBG spill": the amounts to be entered into the SBG VA are determined by multiplying the foregone production volumes in MWh due to SBG by the regulated payment net of the avoided Gross Revenue Charge (GRC) costs.[21]

Interaction between the HIM and the SBG VA

OPG notes, in its pre-filed evidence and confirmed at the hearing, an unintended feature of the current HIM-SBG VA regulatory construct:

> MR. MILLAR: …Can I direct you to staff 61 of the document I had you pull up before. You discovered there were some unintended consequences

[17] VECC notes that in its pre-filed evidence, OPG discusses the current HIM with respect to its Sir Adam Beck Pump Generating Station only at E1.2.1 page 1
[18] OPG's pre-filed evidence on this issue is presented starting at page 2 of E1.2.1.
[19] Ibid, page 3
[20] Per pp 77-78 of Transcript Volume 4, the spill calculations for Sir Adam Beck are performed by the Niagara River Control Centre while for all other hydroelectric facilities OPG performs spill calculations on an hourly basis. Per page 80 of this transcript, the station operators do the calculations which are not checked by another party.
[21] E1.2.1 page 5. Per page 80 of Transcript Volume 4, this assumes that the price is less than the avoided costs of production as in the opposite case it is not appropriate to spill (waste energy).

to the original hydroelectric -- in fact, the current hydroelectric incentive mechanism, and I think staff summarized it in this interrogatory, so I will read it out. It's about the interaction between surplus base load generation and the incentive mechanism.

What it says, starting at line 11 -- and this is quoted from your evidence: "When SBG spill cannot be avoided because the water cannot be time-shifted or stored, it is irrevocably lost. As a result, the monthly average production falls. The SBG spill, which lowers the monthly average production, is compensated for by entry in the SBG variance account. However, the resulting production profile reduced by the SBG spill volume also generates incentive payments under the HIM. This is an unintended consequence of interaction between the HIM and the SBG variance account."

Is that -- that's the nub of the problem, right?

MR. WILBUR: It is.[22]

Among other things, by way of OPG's proposals in the instant proceeding, OPG proposes to rectify the aforementioned unintended consequence.

The Enhanced Hydroelectric Incentive Mechanism (eHIM) Proposal

OPG begins with a calculation of the expected customer benefits – due to fuel savings of gas-fired generation dispatched off during the peak period and due to increased revenues from export sales by the increase in off-peak export sales revenues as a result of higher prices when OPG's production decreases – of OPG's

[22] Transcript Volume 4, pp 17-18

forecasted time-shifting activities for 2014 and for 2015.[23] These "customer benefits" are estimated to be $36M for 2014 and the same for 2015.[24]

OPG then calculates "an X-factor" for 2014 (35%) and for 2015 (31%) such that, when based on forecasted production volumes and forecasted customer benefits such that, as described below, OPG will receive an incentive payment of $18M in each of 2014 and 2015 in addition to payments based on the regulated price.[25]

The method, by which the total revenues that OPG will receive under its proposal would be calculated, is described as follows:[26]

> MR. JANIGAN: Now, looking at Exhibit 1, tab 2, schedule 1, pages 12 and 13, for your proposed enhanced hydroelectric incentive mechanism, it provides for a regulated payment plus an incentive payment?
>
> MR. WILBUR: You are looking at the formula on page 12; is that --
>
> MR. JANIGAN: Yes, that's correct.
>
> MR. WILBUR: Yes, it does.
>
> MR. JANIGAN: And the regulated payment is just the average hourly production multiplied by the regulated rate, which is then multiplied by the number of hours in the month?
>
> MR. WILBUR: Correct.
>
> MR. JANIGAN: And regarding the incentive payment, is it fair to say that it is an X factor multiplied by the sum of the hourly production differences between actual and average production, weighted by the hourly Ontario

[23] Ibid, page 25 – Note that the increased peak production is partially offset by the increase in GRC costs.
[24] Ibid, page 26 and E1.2.1, page 7, Table 1
[25] E1.2.1, page 13
[26] Transcript Volume 4, pp 44-45

electricity price?

MR. WILBUR: That's correct.

MR. JANIGAN: Now, on page 13, you say you have established X factors of 35 percent and 31 percent for 2014 and 2015, which are set so as to be equal to 50 percent of the forecasted customer benefits of 36 million in 2014 and 2015; is that correct?

MR. WILBUR: That's correct.

MR. JANIGAN: Now, are you proposing to true up, ex post, the X factor, so that OPG gets 50 percent of the forecasted customer benefits?

MR. WILBUR: No, we are not proposing to true that up.

MR. JANIGAN: Are you proposing to true up actual consumer benefits so that OPG gets 50 percent of the actual consumer benefits?

MR. WILBUR: No, we are not.

OPG's proposal is that both the currently prescribed[27] and the newly regulated hydroelectric facilities be subject to its eHIM proposal and SBG VA treatment.[28]

Submissions of VECC on HIM, eHIM, and SBGVA

VECC first notes that the assets underpinning the ability to time shift production are all either currently in rate base (currently regulated facilities) or to be included in rate base subsequent to this proceeding (newly regulated facilities). As such, OPG is either already, or will be, earning a reasonably healthy after-tax RoE on all of these assets.

[27] Transcript Volume 4, pp 28-29 idicates that three facilities that are currently prescribed are subject to HIM treatment for 2013: Saunders (run of river), DeCew (run of river), and Sir Adam Beck (PGS).

[28] Per Transcript Volume 4, page 42, aAlthough there are 48 new hydroelectric facilities to be regulated, the eHIM will only apply to the 21 newly regulated facilities "with modelled production."

VECC further notes that the facilities with the ability to time shift production were designed to be able to time shift production through storage in off-peak periods: as such, VECC submits that time-shifting activity, in and of itself, does not represent any new sort of material incremental risk for the utility.

In respect of the costs of time shifting, the evidentiary record indicates that the only material incremental costs of time shifting production that OPG could provide was $7M per year in 2014 and in 2015 and that these costs were associated with the Sir Adam Beck Pump Generating Station (SAB PGS), as the excerpted exchange below shows:[29]

> MR. JANIGAN: I wonder if you could clarify then. In the Undertaking JT1.4 from the technical conference, you provided that the total time-shifting costs for 2012 as being $7 million and for 2013 $6 million.[30]
>
> MR. WILBUR: Yes, we do.
>
> MR. JANIGAN: These were the costs associated with the Sir Adam Beck pump generating station only.
>
> MR. WILBUR: They are, yes.

For the currently prescribed facilities, VECC notes that Sir Adam Beck (SAB PGS) currently has "vast majority" of time shifting capability.[31] Further, the Beck facility can time shift approximately 600 to 700 MW.[32]

[29] Transcript, Volume 4, pp 43-44
[30] Note that in 2012 and in 2013, the Saunders and DeCew facilities attracted HIM as well as SAB.
[31] Transcript Volume 4, page 29
[32] Transcript Volume 4, page 30

VECC further notes that the newly prescribed assets have an aggregate time-shifting capability of about 2100 MW,[33] or about triple the time shifting capacity of SAB PGS, the only major storage facility in Canada.[34]

Notwithstanding the overall quadrupling of existing time shifting capacity, the evidence is that the incremental cost of time shifting for the newly prescribed facilities is not material as the exchange below indicates:

> MR. JANIGAN: Now, given that your forecasted 2014 and 2015 time-shifting costs are 7 million, which includes the costs of Sir Adam Beck pump generation station and the newly regulated hydro facilities, it would appear that the run of river and the non-pump generation hydro facilities, that the time-shifting costs are pretty minimal.
>
> MR. WILBUR: At the PGS the time-shifting costs are easily quantifiable, and they mainly consist of the fact that when we use a specific amount of -- when we pump a specific amount of water into the PGS it takes quite a bit more energy to do that than we will get when we generate that same quantity of water, so there is an efficiency loss.
>
> At the newly regulated facilities there are costs, but they are not as easily quantifiable. I guess an example -- I have two examples which I think I discussed at the technical conference as well. One is, we may operate a facility to get higher output than normal beyond its most efficient operating point, and so there is a cost associated with that.
>
> And also, there are -- there would be additional or lower maintenance costs

[33] Ibid, pp 30-31
[34] Ibid, page 134

if we were to operate the hydroelectric on a flatter profile, do less time-shifting. There would be less starts and stops at these units.

MR. JANIGAN: I am a little confused here. First you told me there was more capacity for time-shifting in the facilities that you are adding, and then you told me that you have difficulty estimating the cost of that time-shifting, so that the only costs that are effectively represented here are the costs associated with Sir Adam Beck.

MR. WILBUR: Yes, so the newly regulated facilities are not the same as Sir Adam Beck. Sir Adam Beck is a pump generating station, whereas the newly regulated facilities are dams where we can store water and choose when to operate those units.

MR. JANIGAN: And they have costs, but they are not reflected here?

MR. WILBUR: That's correct.[35]

VECC submits that the costs of time-shifting, as provided by OPG on the record, are virtually constant for the years 2012, 2013, 2014, and 2015: to VECC this indicates that the incremental financial risk associated with time shifting production at either the currently regulated Saunders and DeCew facilities, or at the 21 newly regulated facilities is not material – otherwise there would be some quantification of these costs at facilities other than at SAB PGS and such costs would be reflected in the evidence and the proposal. The absence of such quantification indicates that OPG does not have any material concerns with respect to the non-SAB PGS time-shifting costs.

[35] Ibid, pp 43-44

Furthermore, VECC notes that there is no evidence on the record that, over any particular year, OPG is at risk of losing money as a result of its time-shifting production volumes.

Given then that OPG is using facilities for the purposes for which they were designed, that they are receiving a return on the assets regardless as to how they are used, that the quantifiable costs of time-shifting are flat, and that OPG does not appear to be bearing any risk by time-shifting, VECC is uncertain as to why any incentive to time-shift production is required.

OPG has contended that they had an incentive to time-shift production at the SAB PGS, even under Ontario Hydro, in the form of reduced costs of operating peaking resources such as oil and coal fired generation.[36]

With respect to the Sir Adam Beck Pump Generating Station, VECC notes that the facility has been in service since 1957/1958 per OPG's webpage; [37] SAB PGS came under OEB regulatory jurisdiction in 2005 and the HIM was established in the EB-2007-0905 proceeding.[38] In any case, SAB PGS was operated, presumably prudently, from 1957/58 to 2007 absent any direct financial incentive payment for time shifting.

However, given that the Board has found a financial incentive appropriate with respect to hydroelectric time shifting activities, VECC submits:

(i) The proposed eHIM is unnecessary because the "double counting" problem could be addressed by OPG under the existing HIM by simply adjusting the balance in the SBG VA appropriately to remove the "double counting" i.e., the increase in incentive payments by spilling

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[36] Ibid page 47 and L S22 Tab 5.4 (VECC 004)

[37] http://www.opg.com/generating-power/hydro/southwest-ontario/Pages/sir-adam-beck-pgs.aspx

[38] Transcript Volume 4 page 48 and page 105

water and thereby reducing the market price. In VECC's view, this is an easy and appropriate easy fix for the problem;[39]

(ii) OPG's proposal de-links the ratepayer benefits from actual financial incentives, instead relying, on an ex ante calculation of forecasted customer benefits while neither truing up for actual customer benefits or adjusting the X-factor ex post to reflect actual customer benefits. VECC submits that the established HIM mechanism is superior to the proposal;

(iii) VECC notes that OPG's incentive revenues under its eHIM proposal would be based on actual incentive revenues,[40] unlike the customer benefit which would not be trued up, either regarding the X-factor, regarding actual customer benefits, or the actual incentive revenues. This leads to the possibility of OPG unduly benefitting from a scheme which, in VECC's view, is inappropriate;[41]

(iv) OPG's proposal does not embed any revenue offsets in its revenue requirement, unlike the current mechanism. VECC submits that it is appropriate to continue the practice of embedding the first tranche of incentive revenues as an offset to the revenue requirement: this provides a strong incentive for OPG to earn beyond this first tranche. With respect to the size of the offset, VECC submits that Board Staff's submissions may provide appropriate direction;

(v) A second tranche of incentive revenues, equal in amount to the first, could be provided for OPG, incenting OPG to earn the full tranche;

(vi) Incentive revenues in excess of the second tranche could be split 50:50 between ratepayers and OPG, providing an incentive for OPG to earn beyond the second tranche;

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[39] Ibid, page 20, OPG admits this can be done

[40] Ibid, page 92

[41] For example, see L Tab 5.4 S 17 SEC 073

(vii) Even under the existing HIM, by bringing the newly regulated facilities under regulation, ratepayers will now be responsible for covering the difference between the GRC and the market price for SBG spill incurred when price is less than the GRC: this provides considerable additional revenue for those 21 facilities, with three times the time-shifting capacity of SAB PGS, for OPG (estimated to be over $30M) that would not be available to OPG had the newly regulated facilities remained unregulated.[42] [43] VECC submits that the existing HIM be applied to all hydroelectric production with modelled production, subject to appropriate adjustment to the first two tranches;

(viii) Given that OPG can correct the current (2013) SBG VA balance to correct for the "double counting" (spills increasing the incentive), VECC believes it is appropriate for the Board to consider whether the 2013 balance should be adjusted to reflect this correction.[44]

(ix) VECC supports the submission of Board Staff with respect to retention of the HIM with adjustments for the sizes of the first two tranches and believes that there is merit in the Board considering the suggestion by Staff for an increased share for ratepayers (i.e., greater than 50%) for incentive revenues in excess of these tranches.

(x) VECC submits that the current HIM should be retained, the proposal to discontinue the HIM VA be denied, the sharing proposal of Staff de approved, and that the SBG VA balance should be adjusted to remove the "double counting" effect whereby spills increase the incentive.

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[42] Ibid, page 37, OPG states that they intend to operate the facilities in 2014 and 2015 the same as they operate them currently. Changing HIM to eHIM appears not to provide an incentive that is required.

[43] Ibid, pp 81-83, the impact on ratepayers of paying for SBG on the newly regulated facilities will increase ratepayers' costs in 2014-2015 by about $34.3M, i.e., the total estimated SBG costs(94.1M) less total GRC (14M) multiplied by the share of newly regulated SBG (0.3+0.6) as a fraction of total SBG (0.6+0.6+0.3+0.6). That is, (94.1M-14.0M)x(0..3+0.6)/2.1 = 34.3M

[44] Ibid, page 161, Undertaking J4.7

6. OPERATING COSTS

Corporate Costs

6.8 Oral Hearing: Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.9 Oral Hearing: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Generally, VECC is concerned with (i) the recent increase in top management positions compared to other positions at OPG reflecting an exacerbation as to what was already a "top heavy" management,[45](ii) the necessity of what appears to be unnecessarily lucrative long term incentive plans provided solely to senior management,[46](iii) the fully loaded compensation costs which appear to indicate that the average non-senior management employee would make "the sunshine list,"[47] and (iv) the potential for employees to assist relatives in securing employment at OPG, undetected by the Chief Ethics Officer.[48]

With respect to the last item, VECC submits that voluntary self-compliance and spot audits may not be sufficient to ensure that issues involving nepotism can be fully addressed.

Otherwise, VECC has reviewed the submissions of Board Staff in respect of Issues 6.8 and 6.9 and supports these submissions.

Costs

VECC submits that its intervention has been responsible, focused and should be of assistance to the Board in determining the issues herein. As a consequence, VECC requests 100% of its costs for participation in the within hearing.

All of which is respectfully submitted this 26th day of August, 2014.

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[45] Transcript Volume 10, page 158
[46] Ibid, page 166
[47] Ibid, pages 161-162
[48] Ibid, pages 167-168.