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26 August 2014

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
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Attn: Ms Kirsten Walli
Board Secretary

Re: EB-2013-0321 OPG Payments – GEC Final Argument

Attached please find GEC's submissions in this matter.

Sincerely,

David Poch
Cc: all parties

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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 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.

GEC FINAL ARGUMENT

August 24, 2014

Contents

Introduction and Executive Summary

The Green Energy Coalition (GEC) represents over 125,000 Ontario residents who are members or supporters of its member organizations: the David Suzuki Foundation, Greenpeace Canada, Sierra Club Canada Foundation and WWF-Canada. All of the GEC's member groups are charitable or non-profit organizations active on environmental and energy policy matters.

In this proceeding GEC has focussed on concerns with respect to the continued poor cost performance of the Pickering nuclear facilities, the cost effectiveness of continued operation of Pickering, and OPG's request for approval of in-service and forecast capital expenditures on the Darlington refurbishment project (DRP). We also address the question of the reasonableness of OPG's commercial and contracting strategies for the DRP and its compliance with the risk minimization principles included in the recent Long Term Energy Plan.

GEC submits that the fact that system planning decisions are made by the government and OPA does not deem OPG's generation to be cost-effective and pre-determine the outcome of the Board's consideration of appropriate payment amounts. Conversely, the Board's determination of the appropriate level of payments does not require OPG to abandon any particular project or facility. If the Board sets payments at a level that reflects an acceptable level of revenue requirement and that does not match OPG's actual spending it is up to OPG and its shareholder to determine if and how to close the funding gap. To determine what is acceptable it is appropriate for the Board to have regard to the cost of comparable facilities and alternatives to new or life extended facilities. In GEC's submission, when such comparisons are made, OPG's Pickering facilities are far from cost-effective and its plans to extend the life of Pickering and to refurbishment Darlington are not the least cost alternatives.

Given that the Darlington refurbishment project is not cost-effective compared to alternatives, GEC submits that the Board cannot find OPG's proposed in-service capital additions and capital spending plans to be reasonable.

OPG has asked the Board to review and approve its commercial and contracting strategy for the DRP. This review is timely given the scale of the project and the government's explicit policy in the LTEP calling for an enhanced risk reduction strategy. The distinction between the LTEP principles and the ordinary regulatory standard of reasonableness is critical. The Government wanted a heightened effort to reduce risk. Given the risks of this mega-project and the dismal history of the sector, OPG has failed to institute a reasonable commercial and contracting strategy and it has failed to reach the higher standard of risk reduction called for in the LTEP.

Issues 6.3 & 6.4 Nuclear O&M Costs, Nuclear Benchmarking Results

Pickering Operations:

In this proceeding the burden lies with OPG to satisfy the Board that the Pickering operating expenses for which the company seeks recovery are cost-effective. Even a cursory review tells us that Pickering, and especially Pickering A, are simply non-cost effective compared to other nuclear generators and certainly are non-cost effective compared to Ontario's non-nuclear alternatives.

Pickering compared to industry benchmarks:

According to OPG, Pickering's total allocated operating costs will be[1]:

2014: $1737.1 million, 81.6 $M/Twh
2015: $1726.7 million, 78.8 $M/Twh

Based on these values[2] the budgeted weighted average cost is 80.12 $/MWh[3]

This compares to the partial 'Total Generation Costs' that OPG utilizes for benchmarking comparisons[4]:

2014: 66.08 $/MWh
2015: 60.25 $/MWh

This distinction is important given OPG's huge pension and OPEB burdens and its high management salaries[5]. The large proportion of centrally held costs and payroll burden allowances that are not included in the partial values used for benchmarking suggest that the benchmarking comparisons may well understate the poor cost performance of Pickering compared to other North American operators.

Even without the pension and OPEB burdens, the benchmarking data clearly indicates that Pickering performs extremely poorly, and remains in the bottom quartile of the industry in stark contrast to the mandate from government: "OPG will benchmark its performance…against CANDU nuclear plants worldwide as well as against the *top quartile* of private and publicly-

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[1] JT1.14 refiled, (L/T1/S1/p2 refilled 2014-06-03)
[2] From these values the implied production estimates are: 2014: $1737.1 million /81.6 M$/TWh = 21.29 TWh, 2015: $1726.7 million /78.8 M$/TWh = 21.91 TWh
[3] [(21.29 X 81.6) + (21.91 X 78.8)]/(21.29 + 21.91). Ignores Pickering's share of the approximately $20 million in stranded nuclear costs that are not on OPG's books.
[4] F2-1-1 p. 15
[5] See for e.g. J7.3 att. 1

owned nuclear electricity generators in North America. OPG's top priority will be to improve the operation of its nuclear fleet." (emphasis added)[6]:

Comparison of 2010 OPG Nuclear Performance to Industry Benchmarks

Metric	NPI Max	2010 Actuals				
		Best Quartile	**Median**	**Pickering A**	**Pickering B**	**Darlington**
Safety						
All Injury Rate (#/200k hours worked)		0.88	N/A[1]	0.77	0.60	0.74
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.05	0.10	0.14 ⇧	0.07	0.09
Rolling Average Collective Radiation Exposure (Person-rem per unit)	80.00	68.64	96.73	138.30 ⇩	93.00	71.55
Airborne Tritium Emissions (Curies) per Unit[2]		2,041	3,784	3,790 ⇧	1,953	969
Fuel Reliability (microcuries per gram)	0.000500	0.000001	0.000036	0.003460 ⇩	0.000205	0.000241
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.06	0.22	0.77	0.24	0.12
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0006	0.0003	0.0000	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0008	0.0077	0.0088	0.0125	0.0067
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0005	0.0010	0.0000	0.0001
Reliability						
WANO NPI (Index)		86.7	77.4	47.7 ⇩	72.6	94.1
Rolling Average Forced Loss Rate (%)	1.00	1.40	3.35	22.52	5.06	1.84
Rolling Average Unit Capability Factor (%)	92.0	91.7	83.7	63.3	80.2	89.4
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.02	1.24 ⇩	1.09 ⇧	1.03 ⇩
1-Year Online Elective Maintenance (work orders per unit)[3]		213	261	333 ⇧	544	281
1-Year Online Corrective Maintenance (work orders per unit)[3]		2	4	14	29	9
Value for Money						
3-Year Total Generating Costs per MWh ($ per Net MWh)		32.54	38.53	90.21	54.79	33.55
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh)		19.00	23.13	75.51	48.49	27.09
3-Year Fuel Costs per MWh ($ per Net MWh)		5.92	6.37	3.70	3.70	3.71
3-Year Capital Costs per MW DER (k$ per MW)		46.30	62.80	62.80	17.41	21.28
Human Performance						
18-Month Human Performance Error Rate (# per 10k ISAR hours)		0.00700	0.01000	0.01150	0.00920	0.00700

Notes
1. No median benchmark available.
2. 2008 data is used for non-OPG CANDU plants because 2010 data is unavailable at the time of benchmarking.
3. Last backlog benchmark in 2010 was as of June 1, 2010.

Green = maximum NPI points achieved or best quartile performance
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = worst quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2009
⇧ Improving Benchmark Quartile Performance vs. 2009

Source: Exhibit L, Tab 6.4, Schedule 17 SEC-092

[6] Exh. A1-4-1 Att 2

In considering this data we note that OPG favours Total Generation Costs as opposed to Non-fuel Operating Costs as a comparator because it is "a more complete value" (indeed, CANDU's cost more to build but use less expensive fuel and have continuous refueling), however the Board should keep in mind that all of these values leave out the full capital costs of OPG's reactors, as approximately $20 million in stranded nuclear costs were not carried over from Ontario Hydro's to OPG's books. Accordingly, while higher capital investment should impart a lower operating cost, comparators that include the fuel savings but do not reflect all of the ratepayer capital invested in OPG's reactors will understate the true costs of OPG's nuclear fleet and give an inaccurate picture of its relative cost performance.

Looking at non-fuel operating costs (which focuses on O&M within management control and leaves aside the capital and fuel distinctions between plant designs), in K5.2 at page 2 we calculated that if Pickering operated at industry median levels the 2014-15 O&M requirement would fall by $1.225 billion[7]. This is despite the fact that CANDU reactors have continuous refueling, which should enable capability factors above industry norms. Accordingly, a comparison of non-fuel operating costs is a conservative one that should favour CANDU reactors.

Pickering does have the disadvantage of small reactor size without a corresponding reduction in staffing requirements. But adjusting for the size of reactors, if Pickering operated at the non-fuel O&M level that Darlington achieves, payments would still decline by $322.42 million.[8] This is likely an underestimate as it does not reflect any economy of scale that Pickering as a 6 reactor station should enjoy compared to Darlington with 4 reactors.

We note that Pickering also performs extremely poorly on most other indicators, including worker radiation exposures and safety system availability indicators (a particularly disturbing reality given Pickering's location adjacent to Toronto). OPG is currently embarking on a multi-year re-analysis of its probabilistic safety assessment that will consider multi-unit events. Given that Pickering A is, on a simple summation of risks basis, already an order of magnitude over its safety target and above its safety limit for large releases, it is not a stretch to assume that the expansion of risk analysis to include multi-unit events will precipitate added safety system expenditures[9]. While safety is not a matter that the OEB regulates, the Board should be alert to the likelihood of costs increasing to address these poor results and the increasing awareness of risk scenarios that will likely emerge from the new analysis.

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[7] Discussed at V. 5, p. 22

[8] K5.2 discussed at V.5, p.24

[9] See discussion at V.5, p. 29. Pickering A's 'simple summation' Large Release Factor risk is 2.68 X 10^{-5} before Fukushima enhancements and 1.26 X 10^{-5}/reactor year after enhancements, compared to a target of 1 X 10^{-6} and a regulatory limit of 1 X 10^{-5} (JT1.15, Att. 2. P. 42).

Pickering A versus B:

As poor as Pickering performance appears, a comparison of the A reactors to the B reactors shows that the A reactors are worse still.

2012 Benchmarking Report Metrics For Pickering A and B

(2011 Actuals)

Metric	Pickering A	Pickering B
Safety		
Rolling Average Collective Radiation Exposure (Person-rem per unit)	136.49	96.86
Airborne Tritium Emissions (Curies) per Unit[1]	3,790	1,953
Fuel Reliability (microcuries per gram)	0.000290	0.000118
2-Year Reactor Trip Rate (# per 7,000 hours)	1.04	0.38
3-Year Auxiliary Feedwater System Unavailability (#)	0.0061	0.0036
3-Year Emergency AC Power Unavailability (#)	0.0152	0.0084
3-Year High Pressure Safety Injection Unavailability (#)	0.0004	0.0000
Reliability		
WANO NPI (Index)	52.8	72.7
Rolling Average Forced Loss Rate (%)	21.39	4.81
Rolling Average Unit Capability Factor (%)	65.1	76.2
Rolling Average Chemistry Performance Indicator (Index)	1.17	1.06

1. 2010 Data is used because 2011 results were unavailable at the time of benchmarking

Source: Exh. L 6.4 S1-Staff 83, p. 2

Value for money benchmarking results that break out the two stations are only available up to the 3 year rolling result for the 2008 – 2010 period, but are presumably indicative of the current relative performance. Those data show that Pickering A's 3 year total generation costs were $90.21/new MWh, close to twice the $54.79 for the B units which themselves are in the 4th quartile[10].

Summary of Nuclear Benchmarking Reports

	---Rolling Actual Results---						---Annual Target ---		
	a	b	c	d	e	f	g	h	i
Darlington	2008	2009	2010	2011	2012	2013	**2014** "Scott Madden" Phase 2 Report	**2014** 2013-2015 Business Plan	**2015** 2013-2015 Business Plan
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.75	98.60	97.90	96.10
2-Year Unit Capability Factor (%	91.99	90.20	89.40	89.60	92.00	90.44	93.30	93.50	86.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	36.75	36.21	42.78
Pickering									
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.52	77.83	72.00	74.20
2-Year Unit Capability Factor (%	67.65	74.47	74.57	72.50	75.62	75.77	82.10	79.90	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	66.84	66.08	60.25
Pickering A									
WANO NPI (Index)	60.84	61.10	47.70				70.90		
2-Year Unit Capability Factor (%	56.60	68.00	63.30				84.30		
3-Year Total Generating Costs ($/New MWh)	92.27	95.41	90.21				70.81		
Pickering B									
WANO NPI (Index)	60.93	70.20	72.60				81.30		
2-Year Unit Capability Factor (%	73.17	77.70	80.20				81.00		
3-Year Total Generating Costs ($/New MWh)	58.68	54.64	54.79				64.80		

Q1 (green) Q2 (white) Q3 (yellow) Q4 (red)

Sources:
Column a - EB-2010-0008 Exh F5-1-1 page 12 (Scott Madden Phase 1)
Column b - EB-2010-0008 Undertaking J3.5 Attachment 1 page 4
Column c - Exh L-6.4-SEC-92
Column d - Exh F2-1-1 Attachment 1 page 3
Column e - Exh L-6.4-SEC-92
Column f - Vol 5 Oral Hearing Transcript June 18, 2014
Column g - EB-2010-0008 Exh F2-1-1 Attachment 1 (Annual Targets agreed based on Scott Madden for inclusion in 2010-2014 Business Plan)
Column h- EB 2013-0321 Exh F2-1-1 page 15 (Annual Targets)
Column i - Exh F2-1-1 Attachment 2 (2013-2015 Nuclear Business Plan - Annual 2015 Target)

OPG Nuclear	2008	2011
WANO NPI (Index)	17th out of 20	24th out of 27
2-Year Unit Capability Factor (%	18th out of 20	25th out of 28
3-Year Total Generating Costs ($/New MWh)	16th out of 16	12th out of 14

Source: J5.2 att.1

[10] J5.2 att. 1

Conclusion: The Board's jurisdiction requires that Pickering costs be disallowed or reduced significantly

There is a fundamental issue before the Board. Where, as here, it is apparent that the costs of operating generators are well beyond industry averages, is it appropriate to allow full recovery of the costs sought? For costs that are committed, the courts have held that a prudence test is to be applied in light of the facts available at the time that the commitment was made. Current and future avoidable (i.e. not committed) costs can be assessed by a reasonableness test in light of current information. In GEC's submission there can be little doubt that OPG's costs do not meet either test. OPG has been tasked by its shareholder to meet benchmarked standards, and the Board in prior cases has called for enhanced benchmarking. Thus OPG has for some time been aware of the facts. Apart from its past long-term capital investments, its commitments and current plans were made, and are all being made, in light of an awareness of industry norms. While OPG and it shareholder may wish to run uneconomic plants for reasons such as transmission system support or system capacity insurance, these are not considerations that are before the Board. The Board's task it is to determine reasonable payments. If reasonable payment levels (judged by way of benchmarking) will not support operations that the shareholder requires for other reasons, it is up to the shareholder to address the cost differential, not the Board through regulated payments unless due to an explicit promulgation of regulations or directives. (The regulation requiring tracking of expenditures on expansion does not apply and in any event does not require the eventual awarding of such costs.) The Board's jurisdiction cannot be said to require it to award payments that ignore continued poor performance or that merely improve on unacceptable performance to a level that is still unacceptable in light of industry standards. The Board has given OPG ample opportunity to present benchmarking data to support its requests and OPG's shareholder has similarly required that the company perform to top quartile standards. OPG has simply failed to perform.

In light of the poor performance of these plants GEC submits that OPG's request for full compensation for its operating costs is unsupportable. Based on industry median levels in the benchmarking data, Pickering's 2014-15 O&M requirement should be reduced by $1.225 billion. However, we recognize that the decision to operate Pickering *de facto* rests with the government and the Board may conclude that to disallow Pickering costs at that level would usurp that function. Accordingly, in the alternative, adjusting for the size of reactors, assuming that Pickering operated at the non-fuel O&M level that Darlington achieves, payments would still decline by $322.42 million and the Board should adjust the revenue requirement accordingly.

GEC notes that the near term payments impact of a complete disallowance of Pickering costs, <u>if</u> it were to lead to a decision to shut down Pickering immediately, would not be equal to the full operating costs of Pickering due to labour contract constraints, accounting cost shifts (including depreciation acceleration and decommissioning and waste management timing impacts) and near term operational costs to defuel the reactors. Most of these costs are, sooner or later, unavoidable, and the differences would be due to timing, a matter that the Board could deal with by way of deferral accounts as part of its consideration of rate mitigation. However, some of these costs such as severance payments can likely be mitigated by good planning. Accordingly, as discussed below in regard to the continued operation of Pickering 5-8, GEC submits that OPG should be required to study the economics of a range of complete or partial shutdowns (Pickering A or B or both) and present those findings in its next payments case. Such analyses should consider alternatives that are available to Ontario including the optimal mix of enhanced renewables, CDM, DR and Quebec imports, not simply gas generation. In addition, GEC submits that OPG should be directed to conduct its labour negotiations and human resources management with a view to mitigating the impacts of a potential shutdown of all or some of the Pickering reactors prior to 2020.

Issue 6.6: Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

While the Board does not make system planning decisions in its payment proceedings, to evaluate cost-effectiveness for the purpose of setting regulated payments it is important that the Board understand the full costs that are incurred by ratepayers due to Pickering operations including indirect costs due to surplus base load generation. The Board should not provide payments or incentives that have perverse effects on customer costs. Further, the Board's record and comments are important input for government planning and the Board may wish to ensure it does not give the false impression that it has concluded that these plants are cost effective compared to other alternatives such as renewables with Hydro Quebec backup or to enhanced CDM and DR.

OPG has canvassed the issue of net benefit before the Board in Exhibits F-2-2-3 attachments 1 and 2. OPG filed these exhibits to support its position that the continued operation of Pickering to 2020 is cost effective. Notably, OPA and OPG differ in their assessment of the benefit of Pickering continued operation (PCO) by more than $400 million. The significant differences are indicated to be due to the treatment of exports, carbon and modelling differences[11]. However, OPG subsequently clarified that the $100 million OPA value and the $520 million OPG value do not include carbon[12] and the OPA memo of Aug. 2, 2012 indicates that the life extension of Pickering, while expected to increase export opportunities, was expected to lower total export net revenues due to its HOEP depressing effect[13]. OPG witnesses took no issue with that assertion. Thus it would appear that the difference in whole or part is due to OPG's estimate incorrectly valuing the export revenue impacts as positive rather than negative.

[11] L.6.6-S.2-AMPCO 52
[12] JT1.19
[13] K5.2 p. 29 Losing Ontarians money on OPG exports is not a new phenomenon: "Based on our analysis of net exports and pricing data from the IESO, we estimated that from 2005 to the end of our audit in 2011, Ontario received $1.8 billion less for its electricity exports than what it actually cost electricity ratepayers of Ontario." http://www.auditor.on.ca/en/reports_en/en11/303en11.pdf (at p.112)

OPG provides the load forecasts utilized by OPG and OPA in their 2012 assessments and the current (2013 LTEP) load forecast in Ex. L.6.6-S8-GEC 7. There we see an approximate 6 TWh/year average drop in the forecast for the period 2014-2020. OPA provides a sensitivity analysis in its April 2012 study that underlies its August 2012 opinion[14]. The sensitivity analysis indicated that a 9 TWh drop would lower the net benefit by $942 million from a $182 million benefit to a $760 million loss. Accordingly, a 6 TWh drop would lower the value by roughly $628 million. This change alone would offset the claimed benefits in OPG's business case even accounting for the money spent to date on continued operations readiness. (OPG's 2014 update shows increased sensitivity to a low forecast scenario going forward[15].)

Similarly OPA provides its forecast of gas prices (which underlie its assessment of the cost of replacement generation if PCO was not pursued) and a sensitivity analysis that addresses gas price changes. Notably, OPA was (and still is) using $5.5/mmBtu for 2015 onward whereas current futures contracts are for prices in the $4.5 to $5 range[16].

OPG and OPA (based on OPG information) assumed and continue to assume an 81% annual capacity factor. For 2012, informed by OPG's evidence the Board approved an 84.9% capability factor but OPG achieved only 77.8 and is now budgeting 79.9 for 2014[17]. Pickering's 3 year rolling average capability factor for the 2011-13 period was 75.77%, falling from the third to fourth quartile WANO performance group. Capacity factor, which unlike capability factor, takes into account external constraints, will be lower still, further eroding value for ratepayers.

The government in its 2013 Long Term Energy Plan made specific reference to the possible shutdown of Pickering before 2020 depending *inter alia,* on progress with the Clarington transformer project. OPG cites the IESO forecast for Clarington to be on line in the fall of 2017[18]. OPA indicated that a 2.5 year shorter life extension (consistent with the Clarington on line date of Fall 2017) would lower net benefits by $228 million[19]. The explicit mention of this possibility in the LTEP policy document is surely an indication that the scenario has a high probability of occurring.

In his letter to the Board of June 9th, 2014 (*which is not evidence tested in this proceeding*) OPA's counsel states that OPA stands by its conclusion that life extending Pickering is beneficial. Certainly, OPA will have concerns about a range of system planning considerations that inform its view. However, OPA's more recent analyses continue to ignore the option of enhanced CDM, DR and renewables as a replacement for all or part of Pickering output that is not surplus to Ontario needs[20]. Given the low cost of CDM and DR this assumption alone challenges the

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[14] K5.2 p. 22
[15] OPA letter of July 25th with responses to GEC and ED questions
[16] K5.2, p. 22 and 46-51
[17] Ex. E-2-1-2
[18] Ex. 6.6-8-GEC-6
[19] K5.2, p.22
[20] OPA letter of July 25th with responses to GEC and ED questions.

meaningfulness of OPA's bottom line. OPA continues to rely on OPG's 2012 projections of cost and performance which are already unravelling. OPA continues to utilize high gas price forecasts despite lower futures prices. GEC has endeavoured to respect the Board's indication that system planning decisions are not in scope in this proceeding. Accordingly, after satisfying itself that the April 2012 OPA memo showing a net loss was not indicative of an intentional withholding of information, GEC withdrew its request to compel the presence of an OPA witness. However, the analyses from OPA make clear that Pickering continued operation is at best, of marginal value and adjusting for the shortcomings in the OPA analysis it is certainly a net economic loser.

The burden in this case is on OPG and OPG has not provided a complete or current assessment. The only information that is before the Board is that for each of the factors in OPA's sensitivity analysis the marginal economics of Pickering continued operations have declined (dramatically in some cases) since 2012. Adjusting OPG's and OPA's 2012 estimates for just one item, the $628 million drop in NPV due to the drop of 6 TWh in the load forecast[21], results in a bottom line of a serious economic loss. (In OPA's 2014 update the sensitivity to a low demand forecast increases from a loss of $.76 billion to a loss of $1.77 billion.)

Of particular note are the OPA's assessments of potential surplus energy (PSE) which in its 2012 assessment shows an added 45 TWh above Ontario needs and in its update 41 TWh.[22] OPG in 2012 indicated that 93% and 94% of the energy from Pickering continued operations in 2014-15 will be surplus to Ontario needs. Its update finds 62% and 66% is surplus in 2014 and 2015 respectively.

Related to PSE is the impact of Pickering operations on surplus base load generation (SBG). OPG has estimates limited to the SBG impact on OPG. The OPA evaluation of PSE suggests that this will be an increasing phenomenon in the next few years. Moreover, the SBG that OPG estimates (for e.g. the 2.1 TWh for 2014-15 in J4.2) is only the SBG that leads to spill at OPG hydraulic plants, not the SBG that leads to curtailment of other resources that Ontarians must nevertheless pay for. The internal OPA memo noted a 2012 forecast of 9TWh of renewable curtailment in the 2014-2020 period due to PCO (the more recent assessment suggests 4TWh). While the forecast value will fluctuate, it is clear that it is quite significant – 4 TWh is roughly equivalent to the total annual output of wind generation in Ontario[23].

OPG acknowledged that neither it nor OPA has assessed the SBG impact[24].

While the decision to operate Pickering B is ultimately dictated by OPG's shareholder, the cost-effectiveness and the fair value for the energy produced is a matter for the Board to consider in setting payments. At the very least the added costs due to SBG that customers must bear

[21] See discussion at V. 5, pp. 42-43
[22] K.5.2, p. 19 and July 25th letter from OPA
[23] K5.2, p. 18
[24] JT1.18

should be weighed. OPG has simply failed to provide the Board with a current assessment of the overall value of operations and in the case of the offsetting losses to customers due to increased SBG it has utterly failed to account for the impact. And while much of the PCO readiness expense is sunk, the bulk of operating costs including completion of PCO readiness is still avoidable. While PCO readiness expense in 2014 is $37.1 million[25] the bulk of avoidable costs are in the incremental cost of running Pickering for the 2014-2020 period. OPA's 2012 assessment of Pickering continued operations was, and its 2014 update is, based on OPG's 2012 estimates of incremental cost of readiness and operations. As the Board will be acutely aware, actual costs have been climbing each year[26]. While OPG is *budgeting* for reductions, since any shortfall between forecast and actuals is borne by the taxpayer shareholder, actual costs are what matters from a societal perspective. And it is actual costs that the Board must try to protect ratepayers and taxpayers from. OPG witnesses indicated that the incremental O&M costs attributable to Pickering continued operations in 2014-15 are approximately $126M and $310M[27]. These costs should be disallowed as OPG has failed to demonstrate that the continued operation has economic value to Ontarians.

Fuel Channel Life Extension

Related to the PCO costs are the costs of Fuel Channel Life Extension. OPG is budgeting $6.6 million for Fuel Channel Life Extension (FCLE) allocated to the Pickering facilities[28]. The bulk of the program cost is allocated to Darlington. OPG hopes that this investigation will allow for a further extension of Pickering pressure tube life to 263,000 effective full power hours (EFPH) rather than the 247,000 that the Fuel Channel Life Management (FCLM) program has sought to justify. The Canadian Nuclear Safety Commission has not yet approved this program[29]. The program is not needed to achieve the 2020 end of life that is planned for Pickering[30]. Ms. Swami also noted that any life extension of Pickering beyond 2020 would require a major vacuum building outage in 2020 which suggests that there is little or no likelihood of such a change of plan[31]. Accordingly, the allocation of some of the FCLE costs to Pickering would appear to be in aid of lowering the apparent costs of the Darlington rebuilding. These costs (2.6 and 4 million in 2014 and 15) should be disallowed or alternatively, reallocated to Darlington.

[25] Transcript v.5 p. 17, l. 17
[26] J5.2, att. 1
[27] As discussed at volume 5 page 20
[28] Transcript v.5, p, 18, l.17-26
[29] V.5, p. 35
[30] V. 5, p. 18
[31] Transcript Vol 7, p. 98

Distinguishing between Pickering A and B going forward

Recognizing that operation of some of the Pickering units may have value to ratepayers as they may be required due to system planning considerations that are beyond the scope of this proceeding (two units are valuable to support the transmission system pending the completion of the Clarington transformer station in the fall of 2017), it is important to consider whether ratepayer and taxpayer value can be maximized by disallowing the costs of a part of Pickering operations. As the benchmarking data makes very clear, Pickering A significantly underperforms on virtually all indicators and certainly on value for money compared to Pickering B. (As discussed above, the Pickering station as a whole underperforms compared to all available comparators.) Ms. Swami agreed that most of the factors that make operation of the A plants alone too expensive and problematic without the B plants do not apply in reverse as the shared safety and support systems are part of the B station[32].

OPA's own analysis of the continued operation of Pickering indicates marginal economic value for the 6 units together. As discussed above, the shortcomings in OPA's analysis (high gas cost estimate, high capability factor estimate, ignoring of CDM and DR etc.) suggest that a proper analysis would indicate that Pickering continued operation is a net economic loser. But even if we were to accept OPA's conclusion of positive value for the 6 units on its face, given how much worse Pickering A's performance is compared to the B units there can be no doubt that its operation has severe negative value. The Board should not reward OPG for the continued losses it is imposing on ratepayers. At the very least, it is certainly reasonable to assume that the government will direct the closure of the A reactors in the near term and OPG should be directed to plan for that eventuality.

While the Board cannot order the shutdown of Pickering or Pickering A, as discussed above, GEC submits that the costs of Pickering operation should be disallowed or, in the alternative, reduced to those comparable to the size adjusted cost of running Darlington. Mr. Stephenson in his panel 4 cross highlighted how a sudden decision to defund some or all of Pickering that resulted in a partial or full shutdown would avoid few payroll costs *in the short term* and would accelerate accounting costs. This is precisely why it is important for the Board to cause OPG and OPA to begin to address this question now when these impacts can be managed and mitigated, rather than in two years' time.

If the Board is not prepared to control these runaway costs in this proceeding, the Board should require that OPG provide, in the next payment application, a detailed analysis of the net benefit/dis-benefit of continued operation of Pickering units with consideration of shutdowns of either the A or B units or all units. Further, OPG should be advised of the Board's interest in these possibilities and encouraged to conduct its staffing management accordingly to reduce severance costs should it be advisable to discontinue operation of the A plants or of all units prior to 2020. To understand the economic consequences of discontinued operation, this analysis should include consideration of an optimal mix of alternatives such as increased DR and

[32] Transcript V.5, p. 55

CDM as part of the alternative case, and increased imports from Quebec, not simply increased gas fired generation. The analysis should also consider appropriate rate mitigation for the resultant shift in the timing of costs such as depreciation and nuclear liabilities.

Issues 4.7, 4.9, 4.10: Darlington Refurbishment (DRP): In-service Capital and Capital Budget

To evaluate the reasonableness of the proposed 2014-15 DRP-related capital budget or the prudence of 2014-15 in-service capital additions, it is appropriate to first consider the cost-effectiveness of the Darlington Refurbishment Project (DRP). If the overall project has not been demonstrated to be economic, surely its sub-components cannot be found to be reasonable or prudent. If OPG can justify initial subcomponents merely by saying they are needed to keep the door open for the main project, there is never going to be any aspect of the project that can't be so justified. Each step is always needed for the next one. This is a bootstrap argument that cannot justify a poor project.

In its November 14th 2013 Business Case Summary OPG compared the median confidence LUEC of 7-7.5 cents/kWh for the DRP with that of CCGT, 7.5 cents/kWh assuming a median long-term gas price forecast of $6/mm BTU[33]. OPG's board made its decision in part based on this comparison, and its witnesses continue to utilize that yardstick[34], but the comparison is quite misleading for a variety of reasons:

First, OPG included a carbon externality value of 0.6 cents/kWh for gas but no externality value for nuclear (for example for the value of the OEFC borrowing guarantee on the significant capital investment needed for nuclear, or the accident risk borne by the public beyond the token amount required by the Nuclear Liability Act[35]). Disregarding externalities of both gas and nuclear, OPG's partial LUEC values are 7.25[36] for the DRP and 6.9 for gas[37].

Second, as the Board will appreciate, and as evidenced in K5.2, p. 46 *et seq.* and subsequently acknowledged by the OPA in its July 25th materials, long term gas prices are currently forecast to be in the under $5 range.

Third, the LUEC values OPG offers for the DRP at the price of $12.9B including interest and escalation are 8.2 (2013)cents/kWh, 8.3 in 2014 dollars[38]. And while OPG now offers values without "fixed corporate overheads and Other Post-Employment Benefits" at 7.8

[33] Ex. K15.1, p. 5a
[34] E.g. V14, p. 16, l.9
[35] V.15, p. 69
[36] See Figure C3 in D-2-2-1 att. 5 at p. 3
[37] K5.1, p. 5a
[38] Exhibit L, Tab 4.7, Schedule 6 ED-005 Page 2 of 2 (and Ex. L tab 4.7 S1, Staff-038)

(2013)cents/kWh and 7.9 (2014)cents/kWh[39], OPG witnesses agreed that in the longer term, if the nuclear program is wound down, 'fixed' overheads could be reduced[40]. Accordingly, these costs are in whole or part avoidable and therefore should be included in the LUEC.

Fourth, LUECs based on the $10B overnight cost estimate are more realistic than the median confidence estimates OPG compared to gas. OPG acknowledges that the $6B figure in it's 6-10 $billion median to high confidence range is no longer realistic and indicates its median confidence for overnight costs is now $8 billion[41]. More to the point, it is only the $10 billion overnight cost estimate that has and had any relationship to OPG's expectation and that corresponds to a value higher than the 8.3 cent figure (which is based on the point estimate that does not include management reserve). As Modus noted:

> "A concept within the estimate that is commonly misunderstood is the application of contingency. Contingency is included in the base estimate and refers to costs that will probably occur based on past experience. As a result, contingency is *expected* to be spent as the project progresses through its life cycle."[42] (emphasis added)

Mr. Gould confirmed that view:

> Mr. POCH: …Do I understand that correctly to mean that from your perspective the realistic cost estimate that people should have in mind for this project is the 10 billion, roughly 10 billion, depending whether you include interest and escalation, that estimate, rather than the point estimate, which I am not going to mention on the public record, but that is without contingency and management reserve?
>
> MR. GOULD: That's correct.[43]

Fifth, CCGT is simply a proxy for the cost of alternatives. In reality the cost would be lower to the extent that Ontario can utilize enhanced CDM and DR at a much lower cost in combination with hydro imports from Quebec. CDM and DR have LUECs under 4 cents/kWh[44].

Sixth, the currently approved pressure tube life is 210,000 effective full power hours. The Darlington units will reach that in 2019 or 2020[45]. Refurbishment will accelerate the shutdown of unit 2 by 2.5 years. Assuming that the CNSC approves an extended fuel channel life of 235,000 rather than 210,000, unit 2 will be refurbished 6 years in advance of its end of life and the refurbishments of the other units (apart from unit 3 that has particular issues) will likely be

[39] J14.4
[40] V.15, p.71
[41] J15.2
[42] Ex. D2-02-02, Attachment 1, June 26,P. 6
[43] Transcript of July 8th, p. 136
[44] OPA, July 25th, page 12: For the period 2015 – 2020, the OPA's estimate of levelized energy efficiency program costs [for CDM] ranges between 3.5 to 4 cents per kWh.
[45] V.16, p. 115 & 124

shut down in advance of their end of (non-refurbished) life. Any added cost due to more expensive replacement power during that period, an expense that could be avoided absent refurbishment, is not captured in the LUEC.[46]

Seventh, OPG makes an optimistic assumption about capacity factor (88% based on the most recent decade) which ignores the history of teething problems in the early years at Darlington that may recur after a major refurbishment. Indeed, in discussing the deferral of the turbine control update on unit two Mr. Reiner specifically referenced the difficulty of 'burning in' these complex mechanisms during the teething period[47]. Darlington's actual average annual capacity factor has been 83.34%[48]. This would raise the LUEC by a further .4 cents[49].

Eighth, OPG does not include the risk of major prolonged multi-unit outages due to a significant event such as a loss of coolant accident[50].

OPA's analyses are similarly flawed due to their reliance on OPG estimates and out of date estimates for the cost of gas which is the proxy utilized for alternatives. Accordingly, it is apparent that even CCGT at something less than 6.9 cents/kWh is far more economic than the DRP at something over 8.3 cents and that the estimate of CCGT at 6.9 cents/kWh is likely high and the estimate for DRP at 8.3 cents/kWh is certainly an underestimate.

When one considers the history of cost underestimation in the Ontario nuclear sector, this conclusion is inescapable.

Given that no case has been made for the cost-effectiveness of the DRP it is unclear how OPG can assert that its related capital budget or proposed capital additions can be found reasonable or prudent. We will deal with each in turn:

DRP In-Service Capital

OPG seeks to add $18.7 and $209.4 to rate base for DRP related expenditures that it claims will be used and useful in 2014 and 15 respectively and that OPG therefore suggests are prudent. The value of these facilities was subsequently increased to $26.1M and $309.4M[51]. While the revenue requirement OPG seeks does not change with the increase due to the small impact on current rates, OPG does seek a finding that a portion of these facilities, a proportion represented by these larger updated amounts, is reasonable and prudent, used and useful. The

[46] V.16, p.49
[47] V.15, p.82
[48] J14.3
[49] V. 14, p. 18
[50] V.15, p.76 & 79
[51] D2-2-2, S2, p.6 Table 1

costs pertain to part of the campus projects which, according to the Modus analysis are already predicted to be 49% over the previous business case budget[52].

OPG agreed that the two components of greatest concern, the D2O facility and the Auxiliary Heating Plant (AHP) are only 10-20% and 35-40% complete, respectively, and that some engineering work is still underway[53]. The D2O facility was originally due to be completed in April of 2015, then April of 2016, now January of 2017 but continues to be under review[54]. OPG is looking at accelerating that schedule and there could be further costs associated with that[55]. There is also a court challenge to the environmental assessment underway which OPA acknowledges could lead to a reassessment of budgets[56]. The challenge is based on the Federal Court finding in regard, *inter alia*, to the treatment of water and sewage in the new build EA. Water and sewage systems are included in the Campus Plan projects in the DRP.

The primary theme of the May 13, 2014 Modus report on the campus plan is that management inexperience was at the root of the cost overrun problem[57].

OPG apparently expects the Board to conclude at this time that a portion of its eventual expenditure on these facilities is prudent despite the fact that the actual cost of the plants is highly uncertain, and that they are largely incomplete.

No benchmarking of costs for comparable projects was offered.[58]

Neither Concentric nor Modus were asked to review the reasonableness of costs.

Moreover, as discussed above under DRP costs, and below under capital budget, these facilities are justified based on the assumption that the DRP is economically justified, a conclusion that is not apparent.

The Modus report makes clear that in regard to the management of the campus projects OPG has simply failed to exercise proper control.

In GEC's submission, OPG has failed to demonstrate prudence in these expenditure decisions, its project planning or its expenditure management to date. OPG cannot demonstrate that its costs or conduct are reasonable or prudent. Moreover, even though a portion of these projects may be in use, they are not required but for the DRP. As the Courts have held, the used and useful principle requires that facilities be required, not that they are merely in use[59]. As the

[52] K15.1, p. 2
[53] V.15, p.63
[54] TC July 8th, p. 59-60
[55] TC July 9th, p. 41
[56] V. 14, p. 79
[57] V.16, P. 29, ll. 11-20
[58] V.17, p.62
[59] *Alberta Power Ltd. v. Alberta Public Utilities Board* (1990), 66 D.L.R. (4th) 286

DRP has not been found to be prudent and required, its supporting facilities cannot be so found.

Darlington Refurbishment Project (DRP) Capital Budget

OPG asks the Board to approve a capital budget for DRP activities of $839.9M in 2014 and $842.5M in 2015[60]. However, OPG's economic analysis supporting the DRP (discussed above) demonstrates that the project is uneconomic and the history of cost overruns in this sector suggests that the eventual outcome is likely to be worse. Neither Concentric nor Modus reviewed the project cost estimates or the capital budget in this case.

As exemplified by the 50% cost overrun on the Campus Plan (thus far), costs and affordability of a project for which engineering is not complete and no release quality estimate exists are anything but clear.

Given that an acceptance of a capital budget as reasonable leads to a presumption of prudence (unless subsequently challenged when the expenditures close to rate base), the Board should be cautious to avoid any determination of reasonableness without adequate and convincing evidence. Both are lacking here.

Can the Board find a budget reasonable for a project that on its face is uneconomic compared to alternatives and for which cost estimates are immature? In GEC's submission, the Board cannot so find.

Issues 4.11 & 4.12: Darlington Refurbishment Commercial and Contracting Strategy – reasonableness – compliance with LTEP

OPG has asked the Board to review and approve its commercial and contracting strategy for the DRP. This review would not ordinarily be included in a consideration of the payments for regulated facilities but is timely given the scale of the project and the government's explicit policy calling for a risk reduction strategy.

Throughout the hearing of this application OPG and its experts repeatedly noted how risk is inherent in megaprojects, and in particular how difficult and expensive it would be to transfer much of that risk to contractors given the uncertainties. In particular, it was noted that until the reactor vaults are entered, there are numerous unknowns that could affect scope or difficulty. In short, OPG says that contractors would charge too much to buy a pig in a poke.

[60] OPG Argument page 55

The consequence of that approach means that the Board is asked to accept, and ratepayers and taxpayers are being asked to assume, the uncertainties of a pig in a poke.

Given the history of dramatic cost excursions for major nuclear projects in Ontario and elsewhere, such projects are in a special category where we submit it is unreasonable to structure the commercial arrangements and contract strategy before every effort is made to understand and monetize the risk. Thus far, OPG and its contractors have not monetized the risk and will not do so until the release quality estimate is complete. GEC submits that the choice of commercial and contracting strategy should be informed by an understanding of the risks to enable the optimal allocation of those risks (and to enable full compliance with the LTEP principles as discussed below) .

As the Board heard during panel 5, there are periodic shutdowns of all units to accommodate major outages such as vacuum building inspections. On such occasions it is possible to enter the reactor vaults. OPG could have scheduled inspections (and allowed potential contractors to inspect) to better understand the risks and enable more risk transfer to the contractors. It did not do so.

Had OPG evaluated and identified risks more fully it could have enhanced its ability to choose a differing contracting strategy that places more risk with the contractors. GEC submits that OPG has accepted an undue risk in its approach that is not a reasonable strategy and is certainly not in compliance with the Long Term Energy Plan (LTEP) principles.

The distinction between the LTEP principles and the ordinary regulatory standard is an important one that OPG has ignored in practice (and in its argument-in-chief) in this case. In the ordinary course the Board would, at an appropriate time, review the proposed capital budget for reasonableness, and at the point where capital is being added to rate base, a prudence test would apply if the presumption of prudence is challenged. However, the LTEP includes six principles applicable to OPG to be applied in pursuing nuclear refurbishments that must be considered in reviewing contracting strategy, principles that extend beyond the ordinary requirement of reasonableness. Three of the principles make explicit reference to cost risk reduction:

The nuclear refurbishment process will adhere to the following principles:

> 1. ***Minimize commercial risk*** on the part of ratepayers and government;
>
> 5. Require OPG to hold its contractors accountable to the nuclear refurbishment ***schedule and price***;

> 6. Make site, project management, regulatory requirements and supply chain considerations, and **cost *and risk containment, the primary factors*** in developing the implementation plan; (emphasis added)

If the government had just wanted the ordinary reasonableness standard for capital budget review or the prudence standard for eventual rate base additions it didn't need to add this explicit list – those tests already applied.

Clearly the government was well aware of the history of significant cost overruns experienced in the Ontario nuclear sector, experienced in many nuclear projects around the world, and experienced by OPG in mega-projects such as the Niagara expansion. The government wants more cost control, i.e. more risk reduction than is business as usual for nuclear proponents. The government wanted OPG to, in effect, buy some insurance by way of risk allocation in its contract structures.

The LTEP principles don't say reasonable or prudent, or lowest contracting cost, or the usual balancing of cost and risk implied by those terms -- they say ***minimize*** risk, and it costs extra to minimize risk.

OPG simply refuses to acknowledge that instruction:

> **MR. REINER: Again, I will say there is no instruction -- I don't read in this any instruction that says: We want you to pay money to shift risk. I am not reading that in these principles[61].**

Despite what GEC submits is a crystal clear instruction to go the extra mile to reduce risk, OPG has used a multi-contractor approach and in the main utilized a cost reimbursable/target pricing approach rather than a maximum cost guaranteed or turnkey approach. Of the total $10B estimate, 93.45% is either 100% OPG costs or subject to target price risk sharing[62]. OPG simply says that further allocation of risk to the contractors would be at a significant cost.

[61] V. 15, p. 37
[62] V.15, p.56

The target pricing approach was used in the initial 'campus' projects that are already expected to exceed the business case estimates by close to 50% (almost all of which is being borne by OPG not the contractors).

OPG retains 100% of the risk on the non-contracted aspects of the DRP budget – i.e. the OPG project management and engineering and the contingency and reserve amounts.

GEC pressed for an analysis of the incentives structure and cost overrun risk allocation in the target contracts. Eventually, OPG provided confidential Exhibit JT3.17 which displays these allocations for various cost overrun scenarios for the expected RFR contract and which OPG explained was representative of the other target pricing contracts. Of note are the facts that OPG pays the cost of any overruns unless under warrantee, contractor penalties are capped, OPG must bear its own project management cost overruns, and OPG must bear costs of delay (interest and escalation) unless the penalty provision kicks in to allow some sharing of that burden (the added costs of replacement energy would be borne by ratepayers). We also note OPG's inclusion in its exhibit of foregone contractor profit and overhead on cost overruns[63]. It must be emphasized that these 'foregone' profits are simply a fantasy, not part of the $10 billion or $12.9 billion project cost estimates, and not relevant to a consideration of the allocation of cost overruns (though OPG apparently considers the 'loss' of fantasy profits on overruns that are the contractor's fault and that were never anticipated in the project to be part of the incentive structure…). The picture painted by JT3.17 is certainly not one of risk externalization that minimizes ratepayer and taxpayer risk. It is clear that OPG bears the lion's share of risk due to contractor under-performance and 100% of all other risks.

And as Concentric points out, a multi-contractor approach means OPG ends up fully carrying risk on those aspects not contracted out and it means OPG carries risk for coordination problems.[64]

For these reasons we conclude that the strategy is not only contrary to the LTEP principles, it is also unreasonable given the scale of the risks and the history of cost overruns in this sector.

OPG provided Concentric's reports on contracting strategy but Concentric analysed the strategy prior to the LTEP and based on the regulatory prudence test. As discussed above, this is not equivalent to the LTEP requirements. Accordingly, Concentric's reports are of little assistance in addressing compliance with the LTEP principles. As to the reasonableness or prudence standard, we submit that Concentric has simply applied the usual test of prudence that is

[63] V15, pp 42-43
[64] K15.1, p. 23A et seq

applicable for routine capital projects to a situation that has extraordinary risk, where there is a history of failure, and where there has not been sufficient effort to quantify and therefore appropriately monetize and allocate that risk. To do so is unreasonable. Mr. Reed views the LTEP principles as requiring nothing more than a business as usual balancing of cost and risk[65]. In GEC's submission that position reduces the LTEP principles to a redundant recital of the status quo approach and could not be what the government intended.

Modus purported to look at LTEP compliance in its March 4, 2014 report noting a few gaps. OPG did not seek to qualify Mr. Gould as an expert witness capable of offering opinion evidence. Thus, all Mr. Gould can offer is a factual look at OPG's actions compared to the more specific LTEP requirements. He was not qualified to offer an opinion on compliance with either the reasonableness standard or the higher LTEP standards. Nevertheless, Mr. Gould (like Mr. Reed) does not suggest that that the LTEP principles require anything more than a business as usual balancing of cost and risk (apart from the unlapping of the unit overhauls). Accordingly, the Modus review cannot be taken as a meaningful review of compliance with the LTEP cost minimization principles unless the Board finds that the LTEP principles are largely window dressing and are not intended to change anything significantly. Moreover, Modus subsequently makes some critical comments in its May 13th report at page 19 under the heading RFR Commercial Risks that indicate contract structure issues. (Modus' comments are not repeated here due to confidentiality but we urge the Board to review them and to have particular regard to those comments and the discussion at Tr. July 9th, p. 91, line 22 *et seq*.).

It is also notable that Modus' critical comments on the Campus Plan commercial strategy only came to light in its July 2014 filing despite the fact that cost overruns triggered a 'deep look' in February 2013. Such a deep dive has not occurred in regard to the balance of the project[66].

The witnesses did not disagree that the most successful example of cost control on a CANDU refurbishment was AECL's work on the Wolsung reactor in Korea.[67] That work was done under a fixed price contract not a risk sharing target pricing contract.[68]

Undoubtedly, even a turnkey contract leaves the owner responsible for scope changes that it requires. But the target pricing approach adds the further sharing of the price risk for contractor failures and delays not covered by warrantees and the retention of major project management and coordination roles leaves OPG and thus the taxpayer and ratepayer holding

[65] See V. 15, pp. 49-50
[66] V.15, p.11-12
[67] V.15, p. 50-51
[68] K15.1, p.27

100% of the risk for much of the project expense. OPG's own descriptions use the phrases: "OPG would retain ultimate control and risk", "with OPG bearing the primary risk" [69] Given the scale of risk and the history, to take that approach is neither reasonable nor in compliance with the LTEP.

OPG in the hearing and in its argument in chief suggests that a turnkey approach would not permit the transparency and hands on oversight that OPG has sought in its arrangements[70]. There is no basis for that conclusion. OPG could have used a primary contractor under a turnkey approach *and* required transparency. Indeed it is clear that under the terms it did utilize it does not direct the work, it merely observes and engages in active discussion to try to minimize problems before they get out of hand. This feature could be included in any commercial and contracting strategy including a single contractor turnkey approach. Similarly, despite OPG's suggestion to the contrary, there is no reason that a turnkey contract could not transfer schedule risk to the contractor. It is just a matter of trading off risk for price.

Apart from vague assertions that more risk and responsibility allocated to contractors would have 'significant cost' and that one of the seven contractors initially under consideration[71] was reportedly not prepared to consider another approach, OPG has offered no evidence to demonstrate that greater compliance with the LTEP principles is infeasible or unreasonable in cost. Modus did not review the price that would be required to further externalize risk and indicated that discussions with contractors would be required to do so[72]. *But OPG did not even attempt to negotiate a fixed price or turn-key arrangement*[73]. The fact that the Lepreau contract ended in litigation due to resulting schedule delays is no reason to dismiss a guaranteed maximum price approach, it is simply indicative of the need to include adequate schedule penalties that reflect actual costs in such a contract. Further, if compliance with the LTEP principles is infeasible or 'too expensive', the correct approach is not to ignore the principles, rather it is to reconsider the project because its true societal cost, including the value of risk, is too high based on the considerations and the rules defined by the LTEP.

[69] Ex. D2-2-1, Attachment 6-2, p. 8 & 14

[70] In its Argument at page 45 OPG states: "This approach is contrasted with the turnkey contracting approach where one contractor is responsible for delivering to the owner a completed project after taking full responsibility for design and execution. The turnkey contracting approach provides for minimal visibility and limited ability for the owner to monitor risk issues and require corrective action. OPG has incorporated key lessons learned in its multi-prime approach. For example, as indicated by OPG, this was a key lesson learned from the Point Lepreau project where decisions were made by the contractor without owner involvement that led to significant delays and costs…"

[71] Three to five can do this work according to Concentric's Mr. Reed: V.14, p. 48

[72] V.15, pp. 31-32

[73] V. 14, p. 40-41 and at p. 51: "No. We did not ask them for a lump sum quote to fix-price the entire job."

GEC submits that it cannot be concluded that OPG has followed a commercial and contracting strategy that is reasonable, nor one that appropriately respects the added cost minimization standards imposed by the LTEP principles. Indeed, it appears that OPG did not seriously investigate options that would adhere to that policy objective.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 26th DAY OF AUGUST, 2014

David Poch
Counsel for GEC