EB-2016-0152

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, Sch. B, as amended;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving new payment amounts for its regulated facilities for the period 2017-2021.

FINAL ARGUMENT ON BEHALF OF

ENERGY PROBE RESEARCH FOUNDATION

("ENERGY PROBE")

May 29, 2017

EB-2016-0152

Final Argument On Behalf Of Energy Probe Research Foundation

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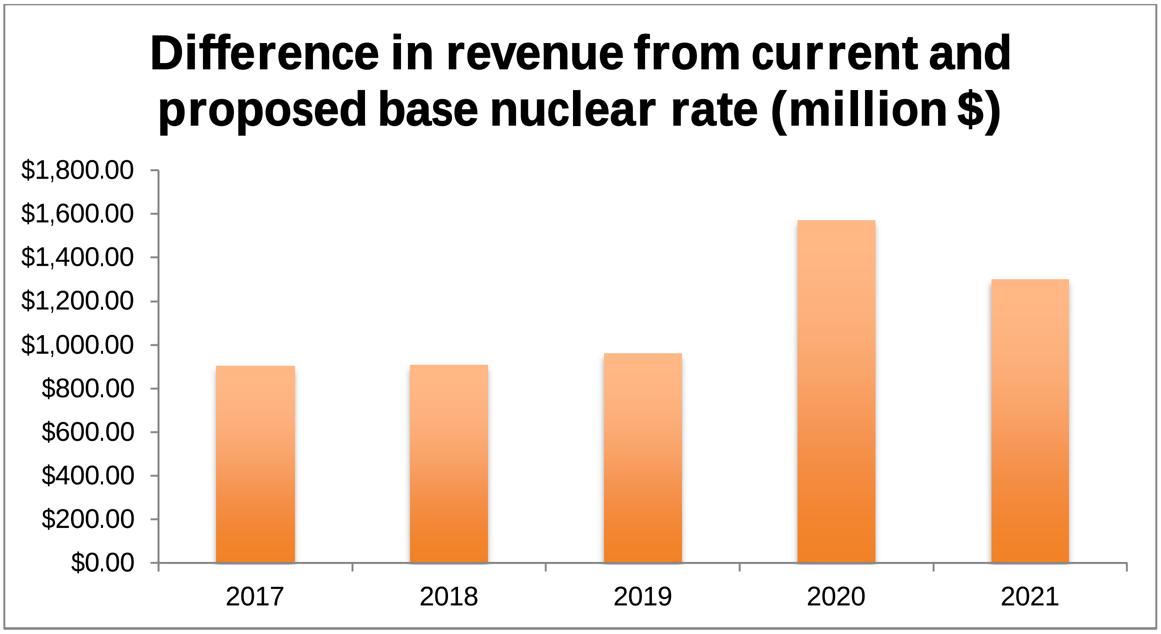
1. Introduction

1.1 On May 27, 2016 Ontario Power Generation (OPG) filed an Application to set payment amounts for its nuclear and hydroelectric facilities for the period starting January 1, 2017 and ending December 31, 2021. Given the amount of material and billions of dollars at stake, OPG was correct in calling this a “significant Application.”[1] The payment amounts relating to OPG’s nuclear business – totalling $16.8 billion over the next five years – are of a scale never seen by the Ontario Energy Board (OEB). Regarding OPG’s hydroelectric business, the company’s application entails revenues of $6.29 billion[2] to $6.88 billion[3] over the test period. In total, OPG’s application proposes more than $23 billion of costs for ratepayers over the next five years. Future rate riders will likely see the total amount of money to be collected from ratepayers be even higher by the end of the test period than forecast in this Application.

1.2 Absent rate smoothing, OPG’s application proposes a base nuclear rate increase of, at one point, more than 70% from its current level.[4] The cost to ratepayers, if nuclear rates were unsmoothed as Energy Probe believes they should be, of OPG’s application are beyond significant. Using the current nuclear base rate of $59.28, the total increase in nominal dollars over the test period in nuclear base rates – using OPG’s production forecasts – is $5.64 billion. While OPG’s proposal for rate smoothing, as required by OReg 53/05, will mitigate those rate impacts, it will do so at a cost to future ratepayers who will be asked to repay today’s deferred amounts plus interest set at the long-term debt rate. The total interest cost over the next five years alone on deferred revenue will cost future customers an additional $470 million[5] by the time OPG starts collecting the deferred revenue.

[1] AIC, page 1
[2] Based on production forecasts in Exhibit I1, Tab 1, Schedule 2, Table 2
[3] Based on production forecasts in Exhibit N3, Tab 1, Schedule 1, Table 2
[4] The current base nuclear rate is $59.29 On an unsmoothed basis, as shown in Exhibit N3, Tab 1, Schedule 1, Attachment 2, Table 5, that rate climbs to $101.28 before slightly declining to $96.03 at the end of the test period.
[5] Undertaking J22.2



1.3 But costs are just one element – certainly the most significant – of the impact that OPG's Application will have for years on the province's electricity grid. While the company's hydroelectric business is in a steady state and will remain predictable in the coming years, its nuclear business is undergoing a massive transformation. OPG has, after nearly a decade of planning, officially begun the $12.8 Darlington Refurbishment Program (DRP) – thereby committing Ontario to another 30 years of nuclear power. As was stated numerous times – and readily acknowledged by OPG – the risks of nuclear refurbishment, for the company, for ratepayers, for taxpayers, for the province's economy and the nuclear industry as a whole, are significant.

1.4 OPG is also asking this Board to approve costs – and, by implication the need – to extend the operating life of the Pickering nuclear plant, otherwise known as Pickering Extended Operations (PEO). The Pickering plant – one of the oldest nuclear plants in the world – is currently scheduled to cease operations in 2020, but OPG is proposing to spend $307 million to extend the operation of all six units to 2022 and four units until 2024. OPG and the Independent Electricity System Operator (IESO) both submitted evidence in favour of extending the life of Pickering. Energy Probe will respond at length to those submissions, but in short, we believe it's premature for this Board to approve costs for a project that has yet to receive regulatory approval – from the Canadian Nuclear Safety Commission (CNSC) – and when a number of the variables that showed PEO would be of "net benefit" to ratepayers have changed in way that's detrimental to the economics of the project.

1.5 OPG has proposed a price-cap index ratemaking plan for its hydroelectric business, which is expected to remain in a steady-state after the in-service addition of the Niagara Tunnel Project. The proposal is in line with the Board's Renewed Regulatory Framework for Electricity (RRFE). As discussed at length below, Energy Probe is supportive of the move towards incentive ratemaking for OPG's hydroelectric assets, but questions the company's proposal for a zero percent productivity factor.

1.6 Due to the size and breadth of OPG's application, Energy Probe has limited its comments to areas of concern to our supporters. We also have broken the argument down into section and provided the issues that each section addresses. We acknowledge throughout the argument areas where we are in agreement with other parties. As other parties have noted, we have worked extensively with other interveners throughout this proceeding in an effort to prevent duplication and have worked diligently to keep our costs as minimal as possible

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2. Summary of Energy Probe's Positions

2.1 To start, Energy Probe has serious concerns over OPG's application and the way in which the company, particularly its nuclear business, is being regulated.

2.2 Through constant interference of regulatory oversight by the province – who is also the sole shareholder of the utility – the regulation of OPG has become limited and subject to growing political interference. OPG is, in our view, increasingly becoming another piece of provincial energy policy, rather than a competitively motivated generator. The recent Fair Hydro legislation, in which OPG will act as the financial manager for debt payments used to lower monthly energy bills, is the most recent example of this interference.

2.3 Yet, the most notable example, in Energy Probe's view, of provincial interference is through the DRP, one of the largest capital projects ever completed in Ontario. As result of legislation passed by OPG's shareholder, the DRP has been shielded from a transparent and thorough examination on whether it is the most cost-effective option for new power in Ontario (essentially, whether it's needed or not). Electricity customers will be footing the bill for this megaproject over the next 30 years without having a clear examination on whether this is the best option for meeting the province's future energy needs.

2.4 OPG is almost entirely shielded from the financial and economic risk of the DRP due to legislation passed by its shareholder establishing the capacity refurbishment variance account (CRVA), which essentially guarantees the full recovery of a majority of its capital costs.

2.5 OPG is also shielded from the risk that the double-digit increase in base nuclear rates needed to bring the refurbished units into service will destroy demand for power and leave OPG with a stranded asset. While OPG's shareholder has made conservation a central component of its energy policy on the premise that it mitigates the risk of "overbuilding" the grid, it passed legislation requiring the OEB to approve a "rate smoothing" plan for nuclear rates, preventing current ratepayers from seeing the "real" cost of nuclear power – and, in short, working against its conservation policies.

2.6 As detailed at length in the Rate Smoothing portion of our argument, the province has determined that the Board should pick "winners" and "losers" between current and future ratepayers – a policy the Board has, admirably, refrained from in the past. The rate smoothing legislation, essentially, ensures that current ratepayers are taking out a loan from OPG – set at the long-term debt rate – in order to catch a break on their monthly bills and passing the cost of that loan onto future ratepayers. We fail to see how the province and OPG can claim this is an example of inter-generational equity.

2.7 And finally, almost all of OPG's generating assets receive regulated rates and no longer bear any market risk – both on the hydroelectric and nuclear side of the business.

2.8 Energy Probe is acutely aware that many, if not all, of these issues are largely out of the scope of this hearing. But we note that the overall objective our organization and our supporters is for a competitive electricity system where the price of power paid by consumers matches the cost of generation. In our view and where possible, OPG should be treated no different than if it were a privately held corporation selling power to Ontario residents. Unfortunately, we find that increased political interference has made that job difficult, if not impossible.

2.9 Nonetheless, Energy Probe supports OPG's proposal to recover the costs of the DRP at a P90 threshold. That said, we believe the Board should consider some form of an Earnings Sharing Mechanism (ESM) for the contingency costs of the DRP, as the current proposal by OPG offers no incentive to the company to bring the project in below budget. As detailed at length below, the P90 estimate, according to OPG, gives the company a 90% chance of hitting its budget, meaning it's reasonable – likely even – that it will beat it. We think the Board should incent the company to beat that target. While we question the veracity of OPG's budget for the DRP, given the history of cost overruns on nuclear projects, we recognize that there is no alternative figure for this Board to consider.

2.10 Energy Probe thinks it's premature to approve the costs for the Pickering Extended Operations (PEO). For reasons explained below, the cost-benefit analyses used to support the project are out of date, OPG's forecasting of capital projects has in the past been subpar and the company has yet to receive approval from the CNSC on whether it will be allowed to operate the plant past 2020 and at what cost. Energy Probe believes that an updated cost-benefit analysis would address many of these concerns.

2.11 OPG's benchmarking metrics show that the company continues to perform poorly compared to its peers. **Energy Probe supports a stretch factor of 0.6% and applying it to both operating and capital costs.**

2.12 OPG's performance on bringing its nuclear capital projects in on budget and on schedule is sorely lacking. OPG has repeatedly said throughout this proceeding that it has learned from its past mistakes and has put in place a process to better forecast in-service costs and schedules. Yet OPG's own evidence shows that it was a breakdown in management that led to a number of delays and cost overruns. Contrary to OPG's claims, the company struggled – sometimes for years – to resolve problems on a number of projects in a timely and cost-effective manner. While Energy Probe doesn't recommend a specific amount of disallowance, we don't believe ratepayers should pay the full price for OPG's mistakes.

2.13 Energy Probe feels that, for the reasons presented below, neither of the LEI or PEG Reports has identified a long-term trend in TPF growth that the Board can rely upon for the IR formula. The alleged trends of both experts are subject to high variability that neither discusses. Energy Probe finds that LEI's reported -1.01% estimate is subject to much greater variability than PEG's 0.29% estimate. Energy Probe shows that the reported growth rates in the experts' aggregate TFP indexes can be replicated by analyzing the unreported sample data; in doing so, it shows that the experts have used very different aggregation procedures and that the PEG Report has not adequately described how its 0.29% estimate was obtained. **With regard to the various differences between the two reports, Energy Probe submits that the Board should adopt PEG's estimate.** Therefore, the Board should also reject OPG's claim that 0% should be adopted as the TFP growth rate for IR."

2.14 OPG's request for a higher equity thickness is misguided and based on the standalone principle, which in Energy Probe's opinion, is difficult to support given the increased and ongoing political interference in the operation of the company. Many of the reasons that OPG cited for why it needs a higher equity thickness don't hold up under closer scrutiny. **Energy Probe sees little reason for why the Board should increase OPG's equity thickness.**

2.15 Energy Probe doesn't support rate smoothing, but recognizes that it is required as a result of legislation passed by OPG's shareholder. **Energy Probe has cited two methods of rate smoothing that either eliminate revenue deferral altogether (though are still in line with the legislation), or limit it to 2020, when the in-service addition of Unit 2 causes a jump in revenue requirement.**

Nuclear

3. DARLINGTON REFURBISHMENT PROGRAM (DRP)

Issues:

4.1 Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?

4.2 Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

4.3 Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

4.4 Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?
4.5 Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?
10.4 Is the proposed reporting for the Darlington Refurbishment Program appropriate?

3.1 At the heart of OPG's application is the Darlington Refurbishment Program (DRP). The total cost of the DRP, if all units are ultimately refurbished, is $12.8 billion and will take a decade to complete. Nearly every witness in this proceeding highlighted the heightened risk of this project – citing the "complexities and the magnitude of this program," [6] pointing out that it will be "statistically unbelievably difficult to get in on budget and on time,"[7] that it throws up a number of "significant financial and operating implications" for the company and, ultimately, that the DRP is a "destiny project for the nuclear industry" by demonstrating that the cost overruns and delays that have plagued nuclear projects are a thing of the past.[8]

3.2 For OPG, the DRP is more than just a megaproject. The DRP is central to the company's future.[9] Without the DRP, OPG's business as we know it today will cease to exist:[10]

> *The closure of Darlington would occur at approximately the same time that Pickering reaches the end of commercial operations and OPG would, therefore, be ceasing all nuclear electricity production.* ***OPG would effectively become a hydroelectric production company****, while implementing a nuclear station safe storage and decommissioning project on 10 nuclear units simultaneously, challenging OPG's project management capacity.*
>
> *The overall reduction in revenue would* ***challenge OPG's ability to meet its future obligations*** *with respect to nuclear waste, decommissioning, etc.*
>
> *If these costs were to be recovered, they would add to OPG's nuclear rates into the early 2020s and would continue to have an approximate* ***20% impact on OPG's regulated hydroelectric rates*** *after all Darlington and Pickering units are shut down. (emphasis added)*

[6] Transcript Volume 5, page 152
[7] Transcript Volume 7, page 54
[8] Transcript Volume 1, page 38
[9] AIC page 3
[10] Exhibit L, Tab 4.5, Schedule 5 CCC-022, Attachment 1, Page 38

3.3 To OPG's credit, it hasn't taken lightly the task of trying to complete a nuclear megaproject on time and on budget. Due to the number and size of the risks inherent in any megaproject, but particularly in the nuclear industry, OPG has tried to meet and exceed industry standards for planning and preparation of a megaproject. Prior to opening Unit 2 for refurbishment, OPG spent a decade and $2.2 billion on planning for the DRP – or about 17% of the project's total budget. Mr. Roberts noted that OPG's planning for the DRP was a "very sound, very prudent approach."[11] He concluded:[12]

> *I would be shocked that if you guys come back four years from now, if this project is over budget, this project is not meeting schedule, it would be very surprising that it was something missed in the planning definition stage. It'd be more -- in my experience,* ***it's going to be highly likely that it was an inability to execute.*** *(emphasis added)*

3.4 OPG's expert also concluded that "OPG had reasonably and prudently prepared itself for the execution of the Darlington Refurbishment Project."[13] The implication from these witnesses and the company itself is that: OPG couldn't be more prepared for the DRP. Given the amount of money and time spent preparing for the DRP, if OPG – and the nuclear industry in general – can't get it right this time, it likely never will. This time really is different, according to OPG.

3.5 From this point forward, at least in terms of the DRP, the risk isn't whether OPG was properly prepared for the DRP – there's no evidence in this proceeding to suggest otherwise – it's whether a). any company can ever adequately plan enough for megaproject, particularly one in the nuclear industry, given the many moving parts and technical complexity b). whether OPG can actually follow through in its execution of those plans. As detailed at length below, Energy Probe is skeptical of OPG's claims that it can handle the execution of DRP, given its struggles on early DRP projects where it experienced cost overruns of more than 200%. Both Mr. Roberts and Dr. Galloway also confirmed that the risk is now largely one of execution.

3.6 But Energy Probe should note here that OPG's budget and schedule forecasts – in which the company built a bottom-up risk registry and then ran those risks through a Monte Carlo model that provided a statistically likely budget and schedule – is only one approach to estimating the final price tag for a megaproject. As detailed in Energy Probe's September 14, 2016 submission to the Board, this is known as a "bottom up" approach. Energy Probe

[11] Transcript Volume 7, page 46
[12] Transcript Volume 7, page 49
[13] Transcript Volume 5, page 138

proposed evidence by world-leading megaproject researchers from Oxford that take a totally different approach to risk and the setting of budgets for megaprojects.

3.7 Many governments and regulatory bodies are now adopting the Oxford approach – known as Reference Class Forecasting – as an alternative to a bottom-up determination of risk and cost and schedule forecasts as performed by OPG. In a follow-up October 3, 2016 letter, the Oxford specialists warned that the bottom up approach "has been demonstrated to lead to optimistic assessments." While there is no formal evidence on record against OPG's approach, our filings highlight that there are experts in the field of megaprojects skeptical of whether those forecasts, even if they meet industry standards, will turn out to be accurate. We should also note that OPG's use of Monte Carlo approach on a nuclear megaproject has never been used before. We have no track record of nuclear new-builds or refurbishments using a Monte Carlo approach as proof that this method will, in any way, be accurate.

3.8 Nonetheless, OPG's response on what constitutes a "success" of the DRP should be telling.[14]

> ***Mr. Lyash****: Well, you know, at the outset, our objective is 12.8 billion for the program, but up underneath that is successful execution of each of these projects at the budget and schedule that we establish in its execution estimate. So the overall objective is 12.8.*

3.9 For OPG, simply hitting a target that it has had nearly a decade and spent $2.2 billion to set would be a glaring success. Given the track record of the nuclear industry, many parties in this proceeding would likely agree that simply hitting OPG's cost and schedule estimate for the DRP would be a giant leap forward for the industry. Energy Probe disagrees for the reasons stated below.

3.10 As part of the in-service amounts for Unit 2, OPG is proposing $677 million of "contingency".[15] Based on its Monte Carlo model and the risk registry that underpins it, that level of contingency means there's a 90% chance that the total budget – both for Unit 2 and the entire DRP – will come in at or below budget. OPG is telling this Board, its shareholder, electricity customers and ratepayers that after a decade and $2.2 billion[16] spent on planning the DRP,

[14] Transcript Volume 1, page 93
[15] Transcript Volume 1, page 114
[16] D2, tab 2, schedule 4, page 2

simply hitting their budget forecast – which its own evidence suggests it will meet nine out of ten times – would be a success. We feel that's a low bar for success.

3.11 Given the statistical probability that OPG will beat that target price and schedule, Energy Probe posits that success should be defined as coming in below the P90 threshold – assuming the Board approves that amount – not simply matching it, which, in our opinion, is the bare minimum. If OPG is correct that its planning and preparation for the DRP was "world class" and "met or exceeded industry standards", then there is no reason for it to define success simply as hitting a target that their own evidence suggests is, statistically, the most likely outcome.

3.12 The concern of Energy Probe is that OPG's application, as presented, provides the company with very little incentive to try and beat its own forecast – doing so would lower its rate base and, subsequently, returns, while any savings from coming in below that target would automatically flow back to customers through the Capacity Variance Refurbishment Account (CRAV). When asked what incentives OPG has to beat its target price, Mr. Lyash pointed to compensation incentives. He noted that the performance scorecard contains annual measures directly related to the DRP, as well as a "longer term set of objectives tied to incentives to ensure that management stays focused not only on just delivering the numbers for this year, but delivers them over the length of a particular project."[17]

3.13 Yet, as highlighted above, Mr. Lyash himself said OPG will declare the DRP a "success" simply if it matches the approved budget and schedule, which in this case is set at the P90 level. Any of the management and other incentives tied to the project will, presumably, be paid out if the project hits what its CEO has defined as a "success", which is, according to OPG's own evidence, 90% likely to occur. Success is, under OPG's framework, essentially a given.

3.14 Meanwhile, OPG is asking this Board to approve $92.5 million in performance incentives tied to its nuclear business over the test period.[18] Under this proposal, OPG is asking this Board to approve incentive payments to be collected from ratepayers before it's clear that any of the performance objectives have been met. When asked why this was reasonable, OPG responded that "the underpinning of performance incentives, which is part of the employment contracts for management group, are based on achieving in effect targeted results over the business plan

[17] Transcript Volume 1, page 121
[18] Exhibit F4, Tab 4, Schedule 1, Table 3

period." Later on OPG noted that part of the business plan meant hitting the target "level of production and costs."[19] Yet, as noted earlier, those business targets simply require the company to meet the P90 level of costs and schedule for the DRP, not exceed that target. As we have already pointed out, OPG's evidence is clear there is a 90% chance they'll hit their budget and schedule.

3.15 Furthermore, as detailed in OPG's performance scorecard, the DRP is just one component of incentives. The DRP could end up missing both its target budget and schedule and OPG management may still collect some level of incentive payments related to other parts of the business. Furthermore, considering that OPG, as the application is currently presented, will already have collected the incentive payments from ratepayers, it may easily find other ways to distribute the money. **The incentive payments, as they currently exist, are not a strong enough tool to bring the DRP under the P90 threshold.**

3.16 Mr. Lyash also pointed to a number of more high-level incentives for OPG to bring the project in below budget – most notably the risk to the company's reputation and the impact that could have on future investments:[20]

> ***Mr. Lyash***: *Perhaps you have a particular incentive in mind that I haven't stated, but I think the incentive to run the company to maximize the opportunity for us to invest, to earn a net income and return on that, to be able to continue with the execution of this destiny project, to be able to deliver this at the lowest possible price and contribute to holding down customer rates as a reputational matter that creates opportunity for us to make future investments in the long-term, these are all very real and tangible incentives for OPG.*

3.17 While those reputational incentives may very well exist, they don't concern how this Board regulates the company. Instead, given that the need for the DRP was established by the company's own shareholder – who is also responsible for determining whether to exercise the off-ramp for the refurbishment of later units – those incentives are largely connected to how OPG's shareholder operates the company in the future. OPG's shareholder also explicitly blocked this Board from examining the economics of moving ahead with DRP, meaning it has little concern over the reputational risks presented by OPG – those are a matter between its

[19] Transcript Volume 21, page 101
[20] Transcript Volume 1, page 122

shareholder (the public) and the company. They simply don't appear to fall under the purview of this Board.

3.18 Energy Probe readily acknowledges that there are incentives to ensure OPG *meets* its budget and schedule targets as they relate to the DRP. But, if OPG's evidence regarding the completeness or accuracy of its risk registry, forecasted budget and preparation activities for the DRP is to be taken at its word – and lacking our proposal for evidence, there is no other evidence to suggest otherwise – it would be statistically unlikely *not* to hit those targets. We fail to see how this application provides a strong incentive for OPG to exceed hitting its bare minimum target.

Earnings Sharing Mechanism

3.19 Energy Probe proposes that the Board approve the P90 budget and contingency – we detail below why a P50 or below threshold is inappropriate – but put in place a 50/50 Earnings Sharing Mechanism (ESM) between the company and ratepayers in relation to contingency costs incurred for Unit 2 below the P90 threshold of $677 million (or an updated figure if one is available). Any costs incurred above the P90 would continue to flow through CRVA and would be dealt with when that account is cleared. As detailed above, Energy Probe believes, as the application is structured, there is little-to-no incentive for OPG to come in below the P90 estimate for contingency and provide greater value for ratepayers. If OPG were to complete Unit 2 below the P90 estimate, the company wouldn't see any of that money – it would instead hand it over to ratepayers, with interest, through the CRVA.

3.20 Energy Probe recognizes that, as opposed to ESMs implemented in other applications that have come before the Board, variances in most of OPG's capital costs flow through the CRVA. The CRVA was established in response to O. Reg. 53/05s. 6 (4) that said OPG should recover "capital and non-capital costs and firm financial commitments" incurred for the DRP and other generation projects. Typically, the ESM is applied to a utility's overall ROE, but in respect to OPG, the Board could specifically apply it to DRP, given it doesn't push the company's total ROE out of the 300 basis point dead band established in the RRFE. Any costs that go over the P90 contingency level continue to flow through the CRVA, as the regulation stipulates, while anything below it would be dealt with through an ESM.

3.21 As it currently stands, the projected cost of the DRP at a P90 level is blended into revenue requirement and rates that OPG is asking this Board to approve. The revenue impact of a P90 contingency is $56 million in 2020 and $67 million in 2021.[21] If there was an ESM in place and OPG only used contingency at a P50 level, the revenue impact in 2020 would, by our rough calculation, be cut by $23 million and $33.5 million in 2020 and 2021, respectively (though we admit those are rough calculations). In our ESM proposal, OPG would be able to keep $11.5 million in 2020 and $16.75 million in 2021. Using OPG's proposed nuclear incentive amounts as an example,[22] annual incentive payments for OPG's nuclear business could potentially increase by 62% and 90% in 2020 and 2021, respectively. Energy Probe feels that's a much stronger incentive for management to find ways to beat their baseline budget, rather than simply hitting it, given that that's the most likely outcome.

3.22 OPG is, in fact, using a type of ESM with the contractors on the DRP. OPG has stated that such incentives will ensure, not only that the cost overruns and scope creep experienced on other nuclear projects doesn't occur, but also that contractors have a very real monetary incentive to come in below cost. We don't see why such a policy shouldn't apply to OPG, the overall manager of the project and the one that, ultimately, bears the risk of the DRP spiralling out of control. Energy Probe doesn't see why a similar model couldn't be applied to the company itself and its management of the DRP.

3.23 We suggest that our ESM proposal is more in-line with the province's Long-Term Energy Plan (LTEP). The LTEP directed OPG to "de-lap" the refurbishment of the first unit of the DRP as a form of insurance policy against "locking in" to refurbing all four units if the costs of refurbishment turns out to be much higher than expected. As such, an ESM dealing only with Unit 2 would encourage OPG to complete that project below cost and leave it to its shareholder to determine what to do with any excess earnings. The shareholder could apply those earnings to compensation incentives, as we detailed above, or it could use that money against future units in the DRP. The key is that if the company is capable of beating a Board-approved budget, it is allowed to benefit from that financially, leaving its shareholder to decide what to do with earnings (who could decide to return it to taxpayers if it wanted to).

[21] Undertaking J8.3. We recognize that this amount is based an in-service amount of a P90 contingency of $694 million, which OPG subsequently lowered to $677 million. But the figures would be close to actuals and provide an illustrative example for the Board to consider.
[22] Exhibit F4, Tab 4, Schedule 1, Table 3

3.24 Energy Probe is aware that many parties may argue for a P50, or lower, contingency. Energy Probe is wary of that argument given the history of nuclear cost overruns in this province, as "lowering" the budget for the project today is likely to be a pyrrhic victory and will hurt ratepayers in the long-run. According to the data from Oxford in our evidence proposal, most megaproject proponents "low ball" the early estimate in order to get the project approved, only to raise the budget later after unexpected events occur. Ultimately, we can be honest with ratepayers and – at least considering what's at stake in this application – apply a budget to the project that is more likely to be real, or we can drop the contingency amount now, only to have it flow through the CRVA and back to the company, at a cost to ratepayers, in the long-run. We can mitigate the rate shock of future ratepayers by dealing with what is a more realistic budget today.

3.25 The risk of cost overruns on the DRP is real and significant. As both OPG's witness (Dr. Galloway) and Board staff's witness (Mr. Roberts) noted during the oral hearing, the Oxford specialists referenced in the paragraph above have detailed at length the likelihood and scale of cost overruns on megaprojects. In the nuclear industry, their database showed that only three out of 100 nuclear projects met their initial cost targets, with 85% of the projects exceeding their initial budget by 10% or more. In total, nine out of ten nuclear projects miss their schedule by more than 10%. Given that a number of early projects related to the DRP, most notably, the D2O building have already come in over budget and highlighted the complexity – and potential for delays, scope creep and increased budgets – inherent on nuclear projects, we take a dim view of OPG's P90 budget.

3.26 Nonetheless the best thing this Board can do, in our opinion, is put in place some sort of mechanism that encourages OPG to not just meet its budget – given, as noted extensively, OPG says this is the most likely outcome – but beat it. Energy Probe is skeptical that OPG will, in fact, meet its expected price tag, but we believe the Board, given the lack of other evidence, should hold the company to it and put in place an incentive for them to come in below that target. An ESM is one way to do that.

3.27 Energy Probe would note that one option that the Board could take would be to consider the tables laid out by Board Staff on page 58 and 59 of their argument. The Board could require OPG could to present such information in its next rate application and the Board could determine whether – even though it approved the P90 contingency level – the spending of that contingency was done prudently. In many ways, OPG's rate application is, in fact, a form of a prudency review of the utility's planning and overall strategy of the DRP. The Board could approve the "prudency" of that planning and strategy, but still review the execution of the Unit 2 portion of the DRP and any contingency spending in the next application. If everything goes as OPG planned, the P90 contingency was prudently managed and any budgets within the Unit 2 that were either over or under were, in essence, done so responsibly within the entire envelope. Ultimately, we believe an ESM is more effective in incenting management at OPG to contain the costs of the DRP, but additional reporting on all contingency spending may also act as a safeguard for ratepayers.

The Third Emergency Power Generator (EPG)

3.28 Energy Probe would like to highlight our concerns on the Third Emergency Power Generator (EPG) project. This project, similar to other early projects under the DRP envelope – as we detail in Section 5 – that fell under the management of the Projects and & Modifications (P&M) organization, experienced significant cost overruns and delays. But unlike those other projects, the EPG remains under the DRP envelope and, as such, its cost overruns will flow through to the CRVA.

3.29 Given that the cost of the EPG has increased from $88 million to nearly $139 million, Energy Probe suggests that some form of disallowance be considered. Similar to other projects overseen by the P&M organization, the Burns & McDonnell/Modus (Modus) audit reports provide a telling picture of a project with a scope and budget estimate that continued to change, while management seemed unable to get it under control.[23] As such, we support Board Staff's submission that the Board only approve the proposed in-service amount of $105.3 million, with the variance between that figure and the eventual final cost undergoing a full prudence review when the company clears the CRVA.

Reporting for the DRP

3.30 Energy Probe thinks OPG's reporting proposal is insufficient. Instead we believe it's more appropriate that OPG file, at least quarterly, more detailed updates as laid out by Mr. Roberts.[24]

[23] See the following reports for a historical timeline of the project: Tab 4.3, Schedule 1 Staff-072, Attachment 5, Page 7, Tab 4.3, Schedule 1 Staff-072, Attachment 8, Page 9, Tab 4.3, Schedule 1 Staff-072, Attachment 10, Page 8, Tab 4.3, Schedule 1 Staff-072, Attachment 11, Page 23

[24] Undertaking 7.1

Energy Probe also thinks the Board should consider putting in place a more aggressive form of reporting, which may entail an independent auditor that reports to the OEB on an annual basis. The problem with megaprojects, generally, is that by the time it's clear that the project has gone off the rails, it's often too late to stop it. In the case of the DRP, OPG's shareholder made it clear that it wants to see how the refurbishment of Unit 2 goes before it signs off on the next three units. In that case, an independent auditor that reports to the OEB would provide a more independent assessment on the performance of the Unit 2 refurbishment than an auditor that is embedded within the company. It will also provide an early metric for whether OPG should continue with planning for later refurbishments and whether those planning costs are prudent given the state of affairs.

4. Pickering Extended Operations

Issues:

6.5 Are the test period expenditures related to extended operations for Pickering appropriate?

Why is Pickering past 2020 needed? Depends on who you ask

4.1 From the outset, it's not clear to Energy Probe what the real reason is to keep Pickering's nuclear reactors operating after 2020.

4.2 The IESO witness, Mr. Pietrewicz, for example, stated that energy demand in Ontario after 2020 could be met by the "existing system, which still has a lot of energy production capability left in it."[25] He noted that meeting energy demand after 2020 – supposing Pickering was shut down as currently scheduled – would be met simply by using current generating assets at a higher capacity.[26]

4.3 Ultimately, Mr. Pietrewicz said that Pickering's real value was to meet peak demand:[27]

> *So if Pickering continues to live a few more years, that pushes out -- that defers the need to invest in those things. And we express those things, those additional resources, in a generic type of cost. And we express it in a generic cost of a peaking gas plant for capacity. So this is capacity that we would require, whether from a peaking gas plant or*

[25] Transcript Volume 8, page 59
[26] Transcript Volume 8, page 59
[27] Transcript Volume 8, page 59

from any other type of resource, we require to satisfy our reliability margins, and then the energy that is not replacing Pickering would from from the existing underlying system, ***so we wouldn't propose to build [a] new plant to replace the energy from Pickering. In fact, they would come from the existing system, just at higher levels of utilization, so our existing plants would operate at higher capacity factors.*** *We would see less curtailments of renewables than we do today, for example.*

So, the energy picture could be addressed by our existing system, which still has a lot of energy production capability left in it. *However, to meet the peak requirements these are requirements to meet a small amount of hours in a year, just at the highest demand hours. We would propose some capacity that is peaking in nature; namely, that is relatively low capital cost that you wouldn't expect to operate very much.*

4.4 Yet, later on, Mr. Pietrewicz said that the continued operation of Pickering past 2020 has other benefits.

I think that's one of the reasons I haven't really highlighted here why, on balance, we supported the continued exploration of this Pickering extension concept, not because we know what gas prices will be or we know what the performance of Pickering will be, but because a lot of things are moving on the system today."[28]

4.5 Mr. Pietrewicz went on to note that the "things" changing on the system include the retirement of 3,000 megawatts of capacity from Pickering coinciding with the refurbishment of eight and half thousand megawatts of nuclear capacity at Darlington and Bruce, as well as the end of contracts for a number of gas generators.

4.6 The risk of those moving parts is significant, according to Mr. Pietrewicz.[29]

"Because any time you have a lot of things moving in a short period of time, there is the prospect of implementation, delay or failure. Things show up late, or not at all. It's easy to drop a ball when you have many balls in the air. This, I think, is a concern for us and that's one of the reasons have 3,000 megawatts at Pickering of an existing assets with access to transmission ***helps to provide some coverage during that period of change."*** *(our emphasis)*

4.7 Mr. Pietrewicz's comments imply that extending the operating life of Pickering offers some sort of insurance policy in a time of significant change for the electricity system as a whole – not simply meeting peak demand, as he originally suggested. As we address in more detail later, Energy Probe questions the "net benefit" of keeping the most unreliable and oldest plants in the

[28] Transcript Volume 8, page 87-88
[29] Transcript Volume 8, page 88

province's nuclear fleet running to provide cover for work on rest of the nuclear fleet. In any case, the continued operation of Pickering, under this argument, is mainly as some sort of insurance policy during the refurbishments of Darlington and Bruce.

4.8 Yet, IESO also said that the economic value of PEO could be positive or negative – in direct contradiction to both OPG and IESO's public comments about it being a net benefit for ratepayers. It's real value, then, at least according to Mr. Pietrewicz, is for "potential coverage" during a time of dramatic change.[30]

> *I'm sorry to go into this long monologue, but the idea here is that the next 10 to 15 years are a source of very significant change in Ontario's power system and with this change, aside from the many opportunities associated with change, there are also risks. And the risks relate to the risks of a many moving pieces variety, which include the risk of implementation delay or failure, which include uncertainties around the future prospects of contracts once they reach their commercial term, and three, uncertainties related to the aging effect on generator reliability.*
>
> *A lot of that is distilled into the early to mid and late 2020s, when we have the maximum refurbishments going on in our fleet. And for that reason, aside from the potential for economic benefit,* ***aside from that potential which we acknowledge here can be plus or negative, right? We don't know. But aside from all that, we think that Pickering provides some important potential coverage during that period of transition.***

4.9 Nonetheless, whether it's being kept operating after 2020 to meet peak demand or provide backup power during multiple refurbishments, IESO was clear that it's not giving this project its full approval. The agency is simply stating that it should taken seriously.

> *Again, I think our view is pretty clear in this deck. We said this has benefit and* ***should be explored further****, and we're categorical about that.*
>
> *What should be explored? We're aware that this is a first cut idea. There are probably details that need to be figured out, and I understand that since that time, OPG has developed this concept further including with information that were provided to us for our October analysis.*

4.10 Similar to IESO, OPG also offered a variety of reasons for why this Board should approve PEO costs, but largely focused its comments on its larger "system value."[31] In fact, according to

[30] Transcript Volume 8, page 91-92
[31] Exhibit F2-2-3, Attachment 2, Page 18 of 22, figure 3.

the company's own cost-benefit analysis, the financial implications, positive or negative, of what it calls "system value" outweighs – to a significant degree – all other variables in OPG's analysis. OPG defined this metric as measuring "the overall systemic economic value and sensitivity...around the demand and the capacity and all of that."[32] To OPG, it appears, the best reason to move ahead with extending Pickering is some sort of overall system value – not peak demand or other more localized variables.

4.11 Later in the oral hearing, OPG narrowed the definition of that system value, by stating that PEO "adds value in terms of being able to provide base load generation during a time of high refurbishment. We understand there is going to be multiple units going off line, and it provides stable base load generation during that period; so there's value that way."[33] In this case, OPG seems to be lining up its support of PEO with one of IESO's points: Pickering will supply base load power while the other nuclear refurbishments increase risk to the system over the next ten years.[34]

4.12 Later OPG also states that PEO is simply good business for the company, as it provides a "revenue stream" for the company while other units at Darlington are being taken offline.[35] So, there's a financial benefit to OPG, as well as a "system wide" benefit to ratepayers.

4.13 Nonetheless, OPG ultimately concluded that, even if the cost benefit analysis was re-run today and it showed a negative value, it would still ask the "Board to approve this project."[36]

> *Yes, I think we would be, because there are other benefits that I think the IESO talked about, and they didn't quantify the value of having Pickering on the system during the time of the high refurbishment cycle that was going on.*
>
> *There's a value for having this asset on the system during that period. It displaces potential future generation that needs to be procured. It mitigates risk associated with the number of contracts that are coming to term, as Mr. Pietrewicz described. It provides sustainable, reliable generation during the period when we are going through a heavy refurbishment cycle.*

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[32] Transcript Volume 13, page 182
[33] Transcript Volume 14, page 53
[34] Transcript Volume 14, page 53
[35] Transcript Volume 14, page 53
[36] Transcript Volume 14, page 55

> ***So they didn't quantify the value of that; it's difficult to quantify the value of that.*** *But that was all incorporated in part of the analysis and the decision-making process. It wasn't just one factor that was a determinant as to whether you should move forward with this project or not.*

4.14 Here OPG implies that the "value" of PEO seems to go beyond any sort of basic cost-benefit analysis and any financial metric it may produce. OPG is also implying in the quote above that the agency responsible for system planning, IESO, didn't actually consider or attempt to quantify these "larger" system benefits.

4.15 Ultimately, it appears to Energy Probe that the PEO is a jack-of-all-trades. At one point, it's being pursued to meet a few hours of peak demand each year. At other times, it's providing "reliable" base load power during multiple nuclear refurbishments. Yet, at other times it's being cited as helping to defer the need for procurement that will eventually be required. At other times, it's providing OPG with a steady source of revenue during a time when its nuclear output will be diminished because of DRP – though we should note that subsequent refurbishments have yet to be approved by OPG's shareholder and are pending the successful completion of Unit 2. And finally, OPG points to some sort of nebulous "system benefit" that appears to go beyond a simple cost-benefit analysis and, as the company suggests, wasn't fully considered by the province's own planning agency.

4.16 In short, before we even consider some of the underlying assumptions that support PEO in IESO's analysis, it's very unclear to us why, exactly, we're keeping Pickering open past 2020. Depending on the question and who is answering, that reason seems to constantly change. Energy Probe understands that the OEB steers clear of system planning issues, but it appears that's exactly what's at issue here: what role does an extended operating life of the Pickering nuclear plant play in the province's energy sector? The answer seems to Energy Probe to be anything but clear.

The Model is Out of Date

4.17 At the heart of the IESO's analysis of whether extending the life of the Pickering nuclear plant would be an economic boost or drain for ratepayers is a number of key variables. Through the oral hearing it became clear that the key variables underpinning the model showing that PEO would be a net benefit for customers have moved against that claim. Energy Probe will walk through those factors below. The three main variables needed to ensure that PEO is of net benefit are:[37]

- The price of natural gas and subsequently, the cost of generating electricity at a gas plant, is above $4.7/MMBtu.
- The capital costs needed to keep the plant running don't exceed 15%.
- Pickering's availability during peak demand remains high.

4.18 According to IESO, if just one of the above risks materializes, then extending the operating life of Pickering will be a net cost for consumers, rather than a benefit. IESO also agreed that if all three of these risks materialize, but any one of them doesn't exceed the threshold, PEO could still be a net cost for ratepayers.[38]

Natural Gas Prices Below Initial Forecast

4.19 Even before we consider the future cost of natural gas prices, IESO's own analysis placed a 70% chance that extending Pickering operations would be a net cost to ratepayers, based on the range of gas prices in recent years.[39] Nonetheless, the price of natural gas, as forecasted by both IESO and OPG in their cost-benefit models, is out-dated and below the threshold in which the PEO becomes uneconomic.[40] For example, using the data confirmed by IESO, it forecast natural gas prices to be $6.12/MMBTu in 2021 in nominal dollars, while the current (in March) forecast for natural gas prices was less than half that at $3.01/MMBTu.

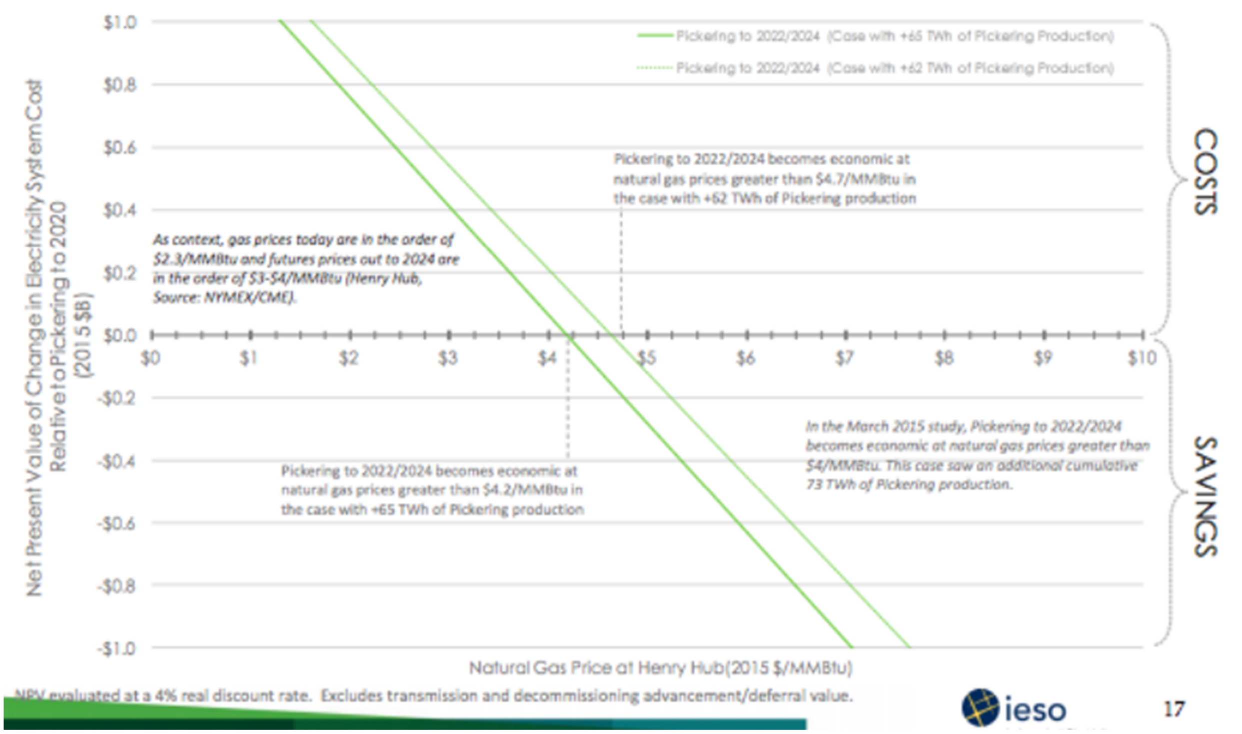
	2017	2018	2019	2020	2021	2022	2023	2024
IESO Forecast (2015 real U.S. $/MMBTU)	5.45	5.45	5.44	5.44	5.43	5.43	5.43	5.43
IESO Forecast (nominal U.S. $/MMBTU)	5.67	5.78	5.89	6.01	6.12	6.24	6.36	6.49
NYMEX Future Prices ($/MMBtu)	3.35	3.05	2.99	3.02	3.01	3.03	3.08	3.16
IESO Price Premium	69%	90%	97%	99%	103%	106%	106%	105%

1 Ex. L, Tab 6.5, Sch. 7 ED-028, Page 5
2 Conversion from 2015 real $ based on assumed 2% annual inflation rate.
3 As of March 6, 2017: http:www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

[37] Exhibit F2-2-3, Attachment 1, Page 3 of 116
[38] Transcript Volume 8, page 56
[39] Exhibit F2-2-3, Attachment 1, Page 3 of 116
[40] Undertaking J8.5

4.20 OPG (and IESO) also stated repeatedly that it excluded the cost of carbon credits from any analysis on PEO. Both OPG and IESO noted that carbon credit costs will increase the price of natural gas and make PEO – and nuclear power in general – more attractive.

4.21 Yet, according to IESO and OPG's own evidence, based on current gas and carbon credit costs, PEO still looks like an uneconomic proposal for ratepayers. OPG's forecast for carbon credit costs between 2021 and 2024 is around $17.47 per tonne.[41] And, according to IESO's PEO analysis, every $20 per tonne increase in carbon credits adds about one dollar per MMBTu to natural gas prices. Using the nominal natural gas forecast for 2021 of $3.01 per MMBTu, that would increase the effective cost of natural gas to around $4 per MMBTu – still well below the threshold of $4.7 per MMBTu that IESO noted was the uneconomic threshold.[42] If those dollar figures were inflated to 2017 dollars, the PEO would likely look even more uneconomic.



4.22 On that figure alone, Energy Probe estimates that extending the operating life of Pickering past 2020 could cost ratepayers as much as $200 million. If carbon costs were excluded, that figure would rise to close to $600 million.

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[41] Exhibit L, Tab 6.5, Schedule 7 ED-029, Page 5 of 5
[42] Exhibit F2-2-3, Attachment 1, Page 64 of 116

Poor Budget Forecasts Could Cost Ratepayers

4.23 OPG has a poor track record when it comes to estimating capital costs (as detailed at length in the following section). In the case of PEO, if those costs exceed the company's current estimate by 15%, the PEO moves from a net benefit to a net cost for ratepayers, holding everything else equal. Given the company's track record on past capital projects, this Board should be concerned about pre-approving costs – and subsequently, it appears to us at least, the need – for PEO.

4.24 For example, OPG has consistently failed to meet its budget forecasts for Tier 1 nuclear capital projects – or those that carry a budget of more than $20 million. OPG originally estimated the total capital cost of its large nuclear budgets to be $1.197 billion.[43] Yet, in its most recent business case summaries, the total cost of those projects has grown by more than $245 million to $1.442 billion – or more than 20%. OPG also has a track record of delays, as the in-service dates on projects from its last rate application with a budget of more than $5 million were, on average, 17 months behind schedule.[44] Of those 25 projects with a budget of $5 million, only 4 projects hit their scheduled in-service date.[45]

4.25 Furthermore, it appears to Energy Probe that OPG's figures for the cost of running the Pickering plant past 2020 and the figures provided to IESO for their analysis don't align. OPG's evidence shows that the full cost of running the plant in 2021 is $1.394 billion and $2.86 billion in 2022-2024.[46] Yet, when asked during the oral hearing what costs OPG had provided to IESO for its PEO analysis, the company said those figures were $1.111 billion and $2.365 billion in 2021 and 2022 to 2024, respectively.[47] The discrepancy between those two figures amounts to $778 million – or about 22%. That discrepancy is well above the threshold (15%) that IESO noted would make the project uneconomic.

4.26 OPG's reasoning for that discrepancy is that the company will lose some "economies of scale" when it shuts down Pickering.[48] That loss of economies of scale is what OPG refers to as

[43] Exhibit L, Tab 4.2 Schedule 2, AMPCO-017 Attachment 1 and excluding projects that have since been deferred.
[44] Transcript Volume 14, page 85-86
[45] Exhibit D2 Tab 1 Schedule 3 Table 7
[46] Exhibit L Tab 6.5 Schedule 1 Staff-118 Page 2, Table 1
[47] Transcript Volume 13, page 141-143
[48] Transcript Volume 13, page 146

its "non-incremental," or non-avoidable, costs – which amounts to, as shown above, $778 million. When asked what costs OPG provided to IESO, the company said that it provided IESO with incremental costs (avoidable costs), as well as the overall nuclear rate if the company were to shut down Pickering as currently scheduled. OPG said that data ensured IESO had a "full view of nuclear costs, if you will, and the incremental piece associated with Pickering."[49]

4.27 Yet, the information OPG gave IESO came from the company's own classification of what it deemed avoidable and unavoidable costs.[50] OPG admitted that it has no "detailed reports or audits" on how it classified what costs are unavoidable if Pickering were to shut down in 2020. The last time the company fully looked at the issue was prior to the 2013 rate application.

4.28 Energy Probe is concerned about the discrepancy between the costs that OPG says are needed to run Pickering past 2020 – which includes both avoidable and unavoidable costs – and the figures given to IESO. As noted above, the difference in figures used by IESO and those by OPG are enough to make the project "uneconomic", according to IESO's cost-benefit analysis. Even if just half the costs that OPG claim are unavoidable actually turn out to be avoidable, the PEO project comes perilously close to becoming uneconomic (holding everything else equal).

4.29 We should also note that the PEO costs are protected by the CRVA and so any overspend will go through a deferral account and it will be up to the Board to prove that the spending was imprudent.[51] If the costs were "prudent", then ratepayers may very well foot the bill for costs that turn the PEO into an uneconomic project. This simply transfers more risk from moving ahead with the PEO to ratepayers and away from OPG. OPG explicitly said it was opposed having the Board look at whether "Pickering extended operations was prudent to continue with" if some of the early cost assumptions turn out to be too low.[52] It appears to Energy Probe that OPG is asking this Board to approve the "need" for PEO now and asking for that determination to be blocked from review in some future proceeding.

[49] Transcript Volume 13, page 138
[50] Transcript Volume 13, page 142
[51] AIC page 23
[52] Transcript Volume 14, page 155

Will Pickering Be Available to Meet Peak Demand?

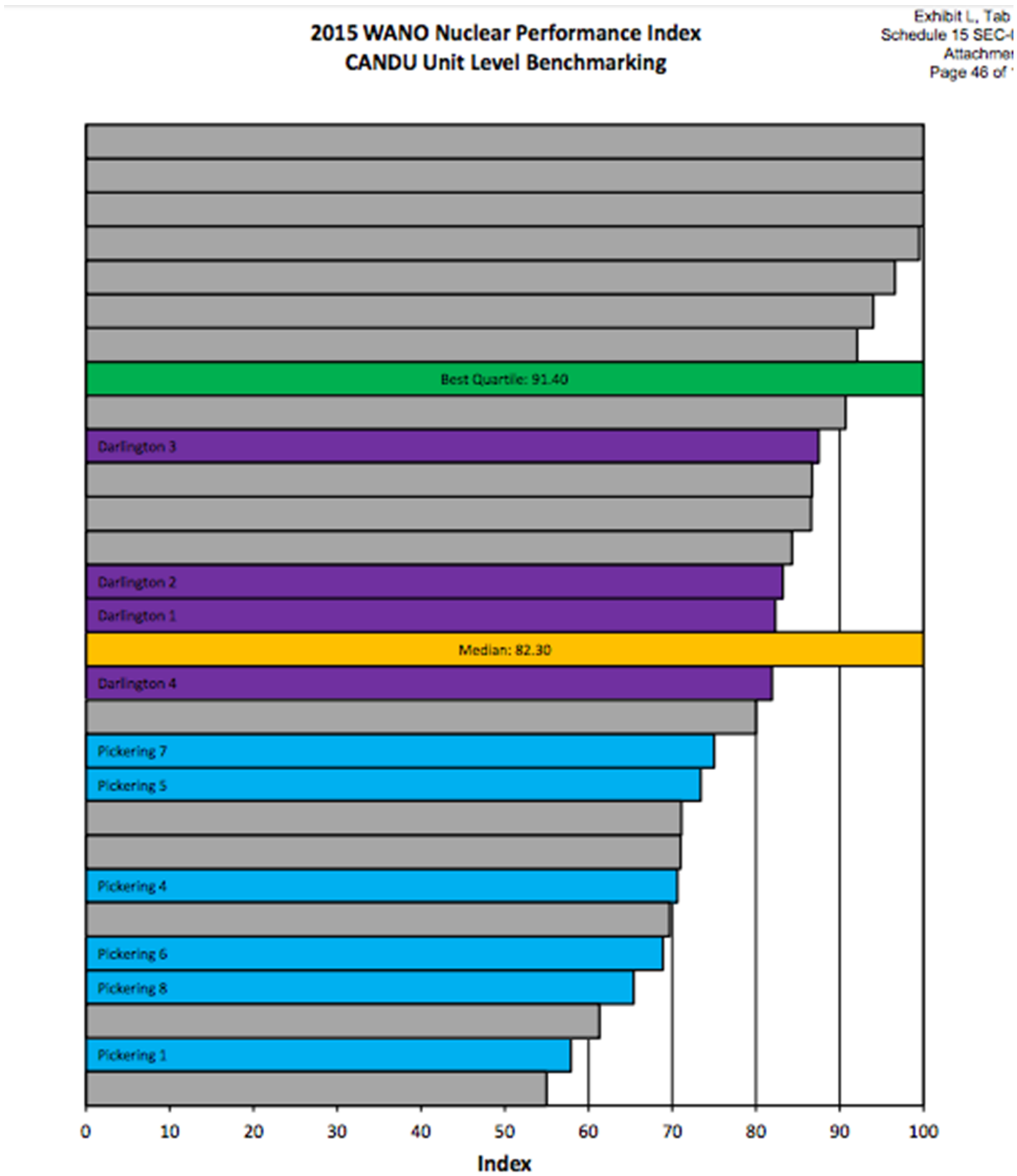
4.30 Pickering, by almost every measure, is a poor performer when compared to other nuclear plants.[53] OPG defends this poor performance, citing Pickering as an early CANDU design and having a lower level of output due to its smaller size.[54] OPG also reiterated that because Pickering is a first generation CANDU reactor, the plant has "substantially more" parts and critical components and, as such, requires more man-hours and outages to keep the plant running.

4.31 Energy Probe sees no reason why the Board should put any weight on those excuses. If Pickering can't be anything more than a third or fourth quartile performer when compared to other nuclear plants, then that's OPG's problem and not one that ratepayers should cover. OPG's argument essentially boils down to: my 1970s vehicle isn't as fuel efficient and cost effective as a newer model, but there's nothing we can do about it, so we may as well just pay up and continue to operate it.

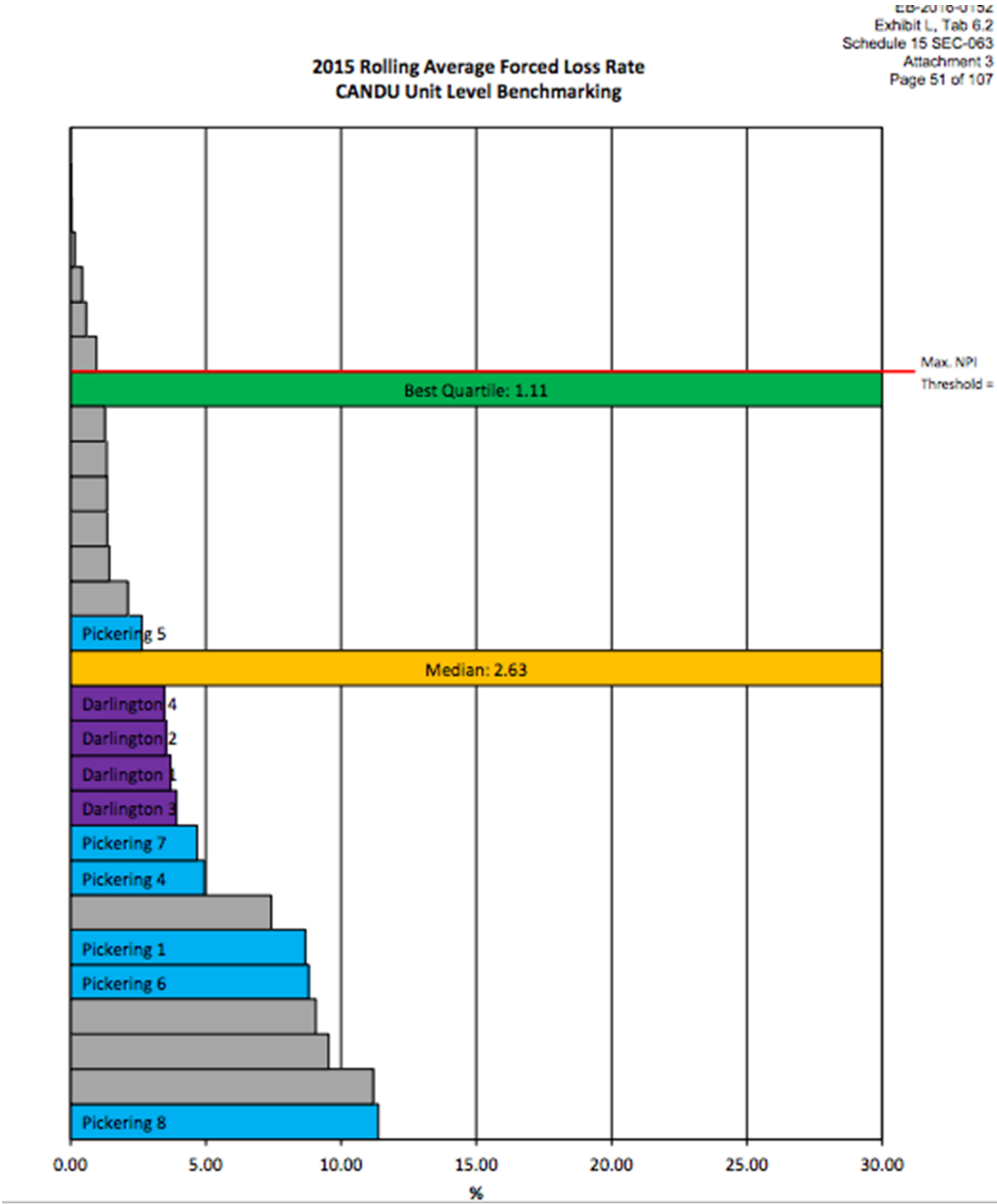
4.32 On the three main reliability metrics – WANO NPI, Unit Capability Factor (UCF) and Forced Loss Rate (FLR) – Pickering is, if not the worst performer, than almost consistently in the fourth quartile.

4.33 Pickering's WANO score, which is an overarching "operational performance indicator" made up of 10 metrics, was well below comparable nuclear plants, with not a single one of OPG's Pickering units scoring above the median in the 2015 study.

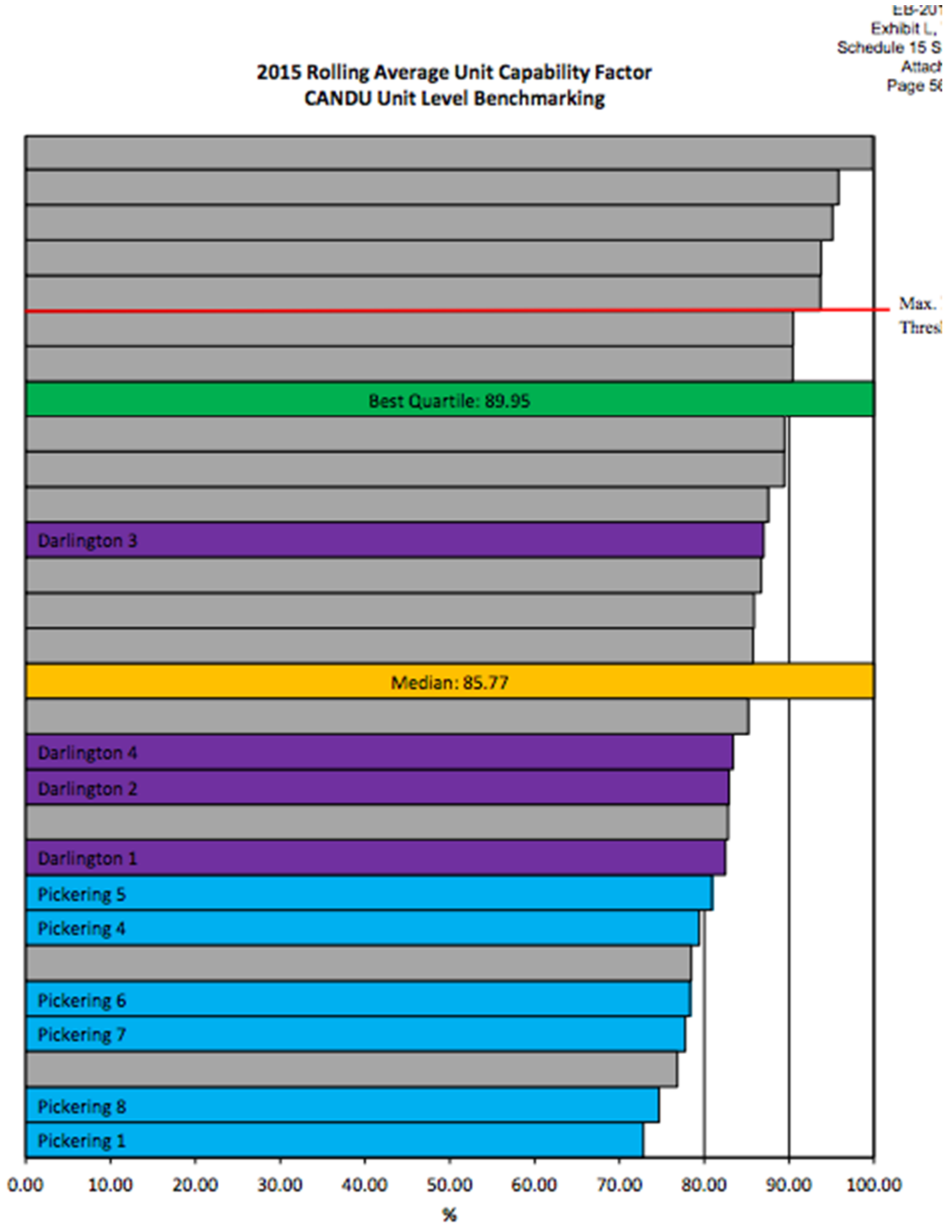
[53] Transcript Volume 13, page 13-14
[54] Transcript Volume 13, page 13 and 30



4.34 Pickering also performs poorly on the FLR, which measures the amount of time of nuclear plant is spent off-line for unscheduled maintenance or repair. One of Pickering's reactors came in dead last in the benchmarking study.

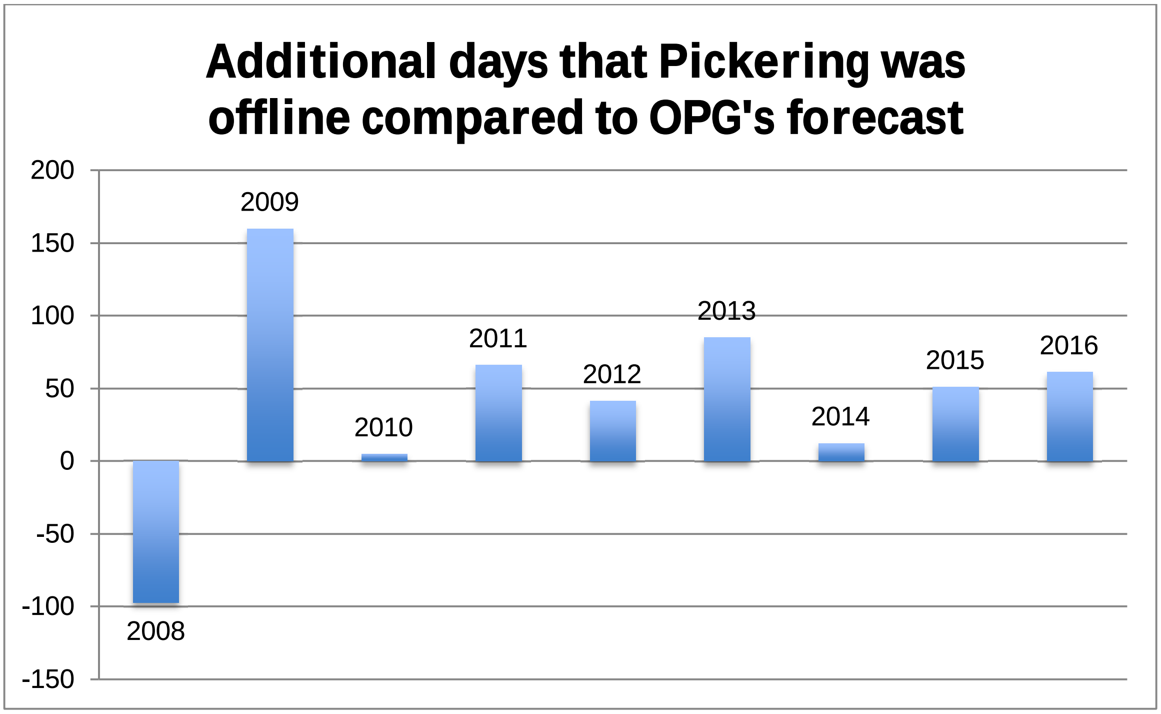


4.35 Pickering's UCF, which measures the amount of power actually generated compared to a plant's nameplate capacity, is, likewise, well below its comparators, with two out of eight units coming in dead last in the benchmarking survey.



4.36 OPG's evidence shows that Pickering often fails to match the company's own forecasts. Looking back at data between 2008-2016, Pickering, on average, required an additional 42 additional days of outages annually than OPG initially forecast.[55]

[55] Undertaking J12.8



4.37 Given Energy Probe's concerns on OPG's benchmarking metrics, we also want to note that, while OPG claims that it's getting better at operating the Pickering units to a higher standard, output from the plant is expected to decline over the test period. The average annual output of Pickering between 2008 and 2016 was 20.06 TWh, while that figure is expected to decline to 19.2 TWh over the test period, or more than 4%, on average, annually.[56] While OPG may be confident in saying that's managed to improve the performance of the Pickering plant, that improvement doesn't actually showup in greater output.

4.38 Furthermore, one reason why output from Pickering is likely to decline over the test period is because OPG is pursuing a far higher number of planned outage days. The average annual number of planned outage days in the test period is 530 days, while it was 283.7 days over the 2008-2016 time frame – marking a more than 86% increase, on average, of outage days annually.[57]While OPG notes that its FLR metric has improved in recent years and will hold at a lower level in the coming years (at 5%), it appears to Energy Probe that, going forward at least, part of that improvement is simply because the company is taking more planned outage days and that, naturally, lowers the FLR – more time offline lowers the need to take forced outages.

[56] J12.9 Attachment 1 Page 1 and Board Staff Compendium Panel 3B
[57] Undertaking 12.10 and Board Staff Compendium 3B, page 120

4.39 Pickering's overall benchmarking metric also gets worse going forward. Of the three four key metrics, only one – the FLR – is stabilizing between 2017-2019. The rest – the WANO NPI, UCF and TGC – all decline over that time period.[58] None of those four metrics will achieve industry best quartile performance in the next three years.

4.40 All of this is to show that, put simply, Pickering is fairly unreliable. Yet, with all of that data highlighting Pickering's unreliability, both OPG and IESO in their cost-benefit analyses determined that the Pickering units would be available during peak demand hours 100% (in OPG's case) or 99% (in IESO's case) of the time.[59] Energy Probe fails to see how that is, in any way, a reasonable assumption, given Pickering's lengthy track record of poor performance. Worse still, is that the IESO witness admitted that as generators reach their end-of-life, their reliability performance gets worse, so we should expect that Pickering's past performance is likely to be better than what we'll see in the 2021-2024 period.[60] The future does not look brighter in terms of Pickering's reliability.

4.41 If Pickering past 2020 is being used largely to meet peak demand, it's not at all clear that it can, in fact, be relied upon to do so. Energy Probe believes this is a major flaw in the "net benefit" argument for extending the operating life of Pickering. Whether it's to meet peak demand or to provide "reliable" base load power, Pickering seems ill equipped to handle either one of those tasks, given its track record and expected performance in the test period and beyond.

CNSC Approval Still Needed

4.42 And finally, underlying OPG's request to this Board for costs needed to extend the operating life of the Pickering nuclear plant is the simple fact that, as of yet, the company has yet to actually receive approval from the Canadian Nuclear Safety Commission (CNSC) to do so. OPG doesn't expect that approval to come until 2018 or later and it's not clear what kind of conditions the CNSC will require in order to keep the plant operating. In Energy Probe's opinion, it's premature to approve costs for a project when it's not clear what level of costs will be needed to keep it operating.

[58] EB-2016-0152 Exhibit N1-1-1, Attachment 1 Page 24
[59] Undertaking J13.13
[60] Transcript Volume 8, page 91

4.43 If, for example, the CNSC grants OPG approval to operate the plant past 2020, but doesn't approve the 261,000 hours that OPG is requesting – say it approves a lesser amount, but above the current 247,000 hours – the entire PEO project could be a net cost to ratepayers, as this Board would have already approved the $307 million in costs needed to keep the plant open past 2020. OPG expects Pickering to produce 62 TWh if kept open to 2024, but IESO admitted that at 56 TWh, PEO becomes uneconomic.[61] This Board should be aware of what amount of power the CNSC will allow Pickering to produce and what level of investment is needed before approving the cost of PEO.

What Should the Board do?

4.44. Energy Probe agrees with the position of Board Staff submitted in an earlier motion that the Board, in this case, is assessing the economic viability of the extending the operating life of the Pickering nuclear plant. Energy Probe submits that the economics of the project are far from certain – if anything, they clearly show that the risk of it being uneconomic are higher than it being of net benefit. We won't reproduce the entire submission – ED already reproduced a large portion of it in its Final Argument – but do think the conclusion made by Board Staff in that motion is important:[62]

> *OEB staff submits, therefore, that the OEB has the jurisdiction to explore the cost effectiveness of ongoing operating costs of Pickering. The results of this enquiry could ultimately be a decision by the OEB to disallow some (or even all) costs related to operating Pickering beyond 2018 or beyond 2020. To be clear, OEB staff is not commenting at this stage on whether or not the proposed costs are reasonable.* ***However, the assessment of the cost effectiveness of continuing to operate Pickering is within the OEB's jurisdiction to consider.***

4.45 Energy Probe would have preferred if a system planning issue such as this was dealt with more clearly by the either the Ministry of Energy, as Bill 135 articulates, or IESO, which can make clear recommendations to the Ministry of Energy regarding supply and capacity issues. Unfortunately, it appears that neither of those bodies has provided the Board with a clear answer whether extending the operations of Pickering past 2020 is the most economic decision for ratepayers.

[61] Transcript Volume 12, page 104
[62] Board Staff, December 9, 2016, page 8

4.46 IESO merely told this Board that it believes that PEO should be "explored further" and that it showed some merit. The province, meanwhile, said the decision rests with the OEB and the CNSC.[63]

4.47 But, as shown above, many of the assumptions and variables in IESO's model purporting to show that keeping Pickering open past 2020 would be of net benefit are now out of date and, in some cases, show the exact opposite – that it would be a net cost to ratepayers. It's clear to Energy Probe that the net benefit of PEO is anything but clear. **We feel the only option is for this Board to order OPG to provide an updated cost-benefit analysis.** In that analysis, OPG – or IESO if it is asked to help – can address many of the concerns raised throughout this hearing. Those concerns largely revolve around updated natural gas prices, a clear and detailed report on avoidable and non-avoidable costs and more realistic assumptions on the availability of Pickering during periods of peak demand.

4.48 In the meantime, the Board could approve costs for 2017 as they relate to PEO, as they may have already incurred (they will go through the CRVA anyways), but refrain from approving costs going forward.

5. NUCLEAR CAPITAL EXPENDITURE AND RATE BASE (EXCLUDING DRP)

4.2 Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

5.1 Energy Probe has left it to other parties and Board Staff to provide detailed recommendations on what levels of capital spend or rate base should be trimmed over the test period. Instead, we want to highlight our view – and the evidence supporting it – that OPG has consistently performed poorly in regards to bringing nuclear capital projects in on time and on budget. While OPG says that it has a new "gated process" that will mitigate – or eliminate altogether – the type of budget creep seen on a number of projects, we question why ratepayers should foot the bill for the lack of such a process in recent years, given that the company already had a similar one in place for the DRP as early as 2010. Contrary to OPG's claims that many of the cost overruns were simply a matter of teething, the company, as highlighted by the

[63] GEC compendium Panel 3A and 3B, page 5

Modus and internal audit reports, has for years faced systemic issues related to the implementation of a number of large capital projects.

5.2 We'll focus our comments primarily on the Auxiliary Heating System (AHS), as we feel this project exemplifies OPG's approach and failures in its capital spending. The original cost estimate for the AHS at the end of 2012 was $45.6 million and was included under the DRP.[64] At the time, OPG's Project and Modifications group (P&M) had an "85% confidence level" in that cost estimate and schedule – even though it had done no detailed engineering and the scope of the project remained unknown. Nonetheless, the AHS project was chosen over seven alternatives, "primarily on the projected cost." By the beginning of 2014, that estimate had jumped to $79.9 million. The original completion date was for 2014. At the time (May 2014), the Modus audit report noted the following deficiencies in the management and execution of the project:[65]

> *The fact this project had so substantially changed from the original BCS was not accurately or timely reported to management. The failure of the gate process was that the Gate Review Board members did not provide adequate oversight in ensuring that the AHS project team had a reliable estimate, schedule, and well-defined scope prior to approving the gate and recommending a funding release. As of January 2014, P&M had already expended nearly $20M, or more than half the approved budget excluding contingency, even though the design was not complete and no construction had begun. However, during this entire time, P&M's estimate at completion ("EAC") in all of the DR Project's and Campus Plan reports* ***never varied*** *from the approved BCS amount. Moreover, the DR Project's Program Status Report for March 2014 showed the AHS at 49% spent with a CPI of 1.10 and an SPI of 1.0, clearly not an accurate representation of the Project's status. Part of this failure was based upon some of the P&M project managers' mistaken belief that the reported EAC amounts should not be changed until additional funds had been approved for the projects.* ***This lack of accurate reporting has deprived senior management and the Board the option of revisiting the original BCS analysis in order to determine if building a new AHS facility continues to be the preferred option—and if not, change course. This is particularly true in light of the fact that as of November 2012, three of the competing options to building AHS were priced at less than $50 M. (emphasis added)***

[64] Tab 4.3, Schedule 1 Staff-072, Attachment 4, Page 9
[65] Tab 4.3, Schedule 1 Staff-072, Attachment 4, Page 9

5.3 By March of 2015, the price tag of the AHS had grown to $85.14 million.[66] In the third quarter of the same year, that price tag had jumped to $99.5 million.[67] The final cost of the AHS system is now $107 million.[68] The AHS is still not complete.[69]

5.4 OPG has defended the growing price tag of the AHS – and other campus plan projects – as growing pains, admitting that the company had an "over reliance on the vendor's proposal."[70] Later on OPG admitted it had "over-confidence" in the companies in charge of executing this and other projects. And later, OPG admits it had an "overstatement of the quality of the cost estimate" related to some of those early projects. [71] Ultimately, OPG readily admits that its estimate of the project and the vendor's capability to complete the work were well off the mark.

5.5 The audit reports from Modus paint a much different picture. They show that, from the beginning, OPG's P&M organization didn't just miscalculate its budget and schedule forecasts, but rather failed on a number of fronts. This wasn't simply an example of growing pains, it was a breakdown on nearly every level – contracting, oversight, an inability to update cost estimates and schedules and a failure to track the progress of the projects. OPG didn't just get the early estimates wrong – it continued to fail to get the project under control years after it had started. The problems, according to the audit reports, were systemic:[72]

> *As noted, these Campus Plan Projects have been plagued by myriad problems that have resulted in significant schedule and cost variances.* ***Our findings show that the predominant cause of these overruns was P&M's original strategy to use a project "oversight" management model for the EPC contracting strategy utilized by OPG that was inappropriate in application and lead to a series of cascading management failures and contractor performance issues.*** *The oversight management model employed a disengaged, "hands-off" approach by the P&M organization which caused the fledgling P&M organization to: (1) wrongly assume that the contractors understood the scope on the basis of performance specifications that outlined scope initial requirements; (2) utilize inexperienced project managers; (3) allow Operations & Maintenance and other OPG stakeholders to initiate scope changes to these projects long after the conceptual design period ended; (4) to accept the poor schedules and cost estimates by the contractors without appropriate vetting and*

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[66] Tab 4.3, Schedule 1 Staff-072, Attachment 8, Page 9
[67] Tab 4.3, Schedule 1 Staff-072, Attachment 10, Page 8
[68] Exhibit L, Tab 4.4 Schedule 15 SEC-046 Attachment 2
[69] Transcript Volume 12, page 150
[70] Transcript Volume 12, page 160
[71] Transcript Volume 12, page 61.
[72] Tab 4.3, Schedule 1 Staff-072, Attachment 4, Page 6

challenge, and which were not updated to incorporate the impact of scope changes on a timely basis; and (5) to inaccurately or untimely report the projects' progress, risks and cost and schedule overruns to the DR Team and senior management. (emphasis added)

5.6 But, even more damning, is that the audit reports show that OPG wasn't simply blindsided by cost increases. In fact, the company *deliberately* attempted to "lowball" the cost estimates on some of these early projects, only to later easily blow past those early forecasts.[73]

> *From interviews with the current P&M staff and the contractors, it appears that these initial BCS estimates were poorly* ***characterized as part of a deliberate management strategy directed by the former VP of P&M****.* ***P&M's managers told us that the contractors were challenged to reduce their bid prices and remove all contingencies for unknowns, despite the extreme immaturity of project definition underlying their respective bids.***
> *…*
> *P&M gave only token consideration to determining which contractor had a better approach for executing the work.* ***P&M chose the "low bidder" even though the other contractor's qualifications and project approach were viewed more favourably. Thus, P&M created the conditions for a perfect storm of cost and schedule overruns.*** *Because the work is largely based on a cost-reimbursable target price with no caps on size, P&M's artificial beating down the contractors' prices in the bid phase was a Pyrrhic victory: P&M's actions did not reduce cost and only served to deprive senior management of realistic cost projections for this work. The budgets for these and other F&I projects were nothing more than paper barriers that were easily surmounted as the design work continued to generate more complex (and expensive) work.*

5.7 When asked why OPG should be able to recover all of the costs associated with this and other early campus projects, the company replied that "the actual work that's performed as [sic] value added work, those are prudently incurred costs so that we deliver the assets that meets the requirements."[74]

5.8 Energy Probe notes the stark difference between OPG and the audit reports on the AHS and other projects. OPG claims that it merely got some of those early estimates wrong, but it's learned from those mistakes and the costs associated with those projects remain prudent. The audit reports, on the other hand, show that OPG made deliberate mistakes right from the beginning and failed to adequately address them, as it simply raised the overall budget for the project through revised business cases as new problems came to light. OPG deliberately

[73] Tab 4.3, Schedule 1 Staff-072, Attachment 4, Page 7-8
[74] Transcript Volume 15, page 131.

pushed the price of the projects down; it chose the lowest bidder even when other companies appeared more qualified; it failed to accurately oversee the contractors performing the work; it used inexperienced managers; and it failed to report the progress of a project that wasn't moving smoothly in regards to its schedule or cost to management.

5.9 It's not just outside auditors that have questioned OPG's ability to bring projects in on time and on budget. OPG's own Refurbishment Construction Review Board Review highlighted that the company had a "cultural tolerance for acceptance of work delays."[75] That review board concluded "there is a lack of understanding of what it means to be an accountable organization."

5.10 We should also note that, while the AHS is no longer part of the DRP, it did initially fall under that project. According to the province's Long-Term Energy Plan (LTEP) – and detailed in OPG's evidence – all DRP projects are expected to have "locked down project scope well in advance of starting construction" and have "fully developed engineering and planning of the work so that it is 100 percent complete prior to the start of construction."[76] Energy Probe submits that the way in which this and other campus plan projects proceeded was in stark contrast to that laid out in the 2013 LTEP. OPG itself admitted that moving ahead with projects prior to completing detailed engineering was a major problem on previous refurbishment projects.[77]

5.11 Energy Probe would also like to note that, while the D20 project was removed from this application mid-way through proceedings, it suffered many – if not all – of the same problems as the AHS project.[78] The D20 project was initially expected to cost $108 million, but has since reached $373 million[79] and counting – marking an increase of 245% [80]

5.12 OPG also had problems on many other projects, according to its own internal audit on the P&M organization.[81] That organization within OPG oversaw $1.1 billion worth of projects over the three-year period from 2015 through to 2017. The findings from an audit on the P&M organization are telling, in Energy Probe's view. The audit reported the following problems:

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[75] Exhibit L, Tab 4.3, Schedule 15 SEC-037 Attachment 2 Page 5
[76] Exhibit D2, Tab2, Schedule 1, Attachment 2, Page 1
[77] Exhibit L, Tab 4.3 Schedule 1 Staff-072 Attachment 25 Page 33
[78] Nearly every Modus report provided detailed findings on the problems with the D20 project
[79] Exhibit L, Tab 4.3, Schedule 'l Staff-072 Attachment 6, Page 6
[80] Tab 4.3, Schedule 1 Staff-o72, Attachment 4, Page 7
[81] Undertaking J7.3, Attachment 1

- The definition scope and accuracy is "sometimes insufficient for the start of a project's execution phase" and led to "significant variances" to estimates.
- Cost and Schedule Control Baselines ("CSCB's") weren't keeping pace with changes to Business Case Summaries ("BCS's")
- The move to a "gated process" had not yet been fully implemented (this audit was completed in March of 2016).
- There were a number of "gaps in governance and procedures."

5.13 OPG says those problems are behind it and it has a new process – which it calls a "gated process" – going forward. When asked about this new process, OPG confirmed that projects would be "finished better" and that this process was put in place by the middle of 2016 (after the audit report cited above).[82] Ultimately, OPG concluded that the "controls are in place today" that will ensure that many of the problems cited in projects reviewed by the audit committee "will not reoccur."[83]

5.14 And yet, OPG acknowledged that, within the company, the gated process and a "center of excellence" were first established as far back as 2010.[84] But those processes were initially only applied to projects within the DRP portfolio. It was a full six years later, after the company experienced multiple cost overruns and management failures, that OPG decided to implement this policy on projects overseen by the P&M organization. Furthermore, OPG failed to bring in this gated process after the Modus audit reports highlighted that the P&M organization was clearly not prepared for the amount of work that it was tasked to oversee, leading to delays, scope creep and poor estimates:[85]

> *Our findings show that the predominant cause was OPG's Projects & Modifications ("P&M") organization, who is managing this work for the DR Project, incorrectly applied an "oversight" project management approach for its EPC contracting strategy, leading to a series of cascading management failures and contractor performance issues, including misunderstandings of scope, uncontrolled scope creep, poor quality cost estimates, unrealistic and incorrect schedules and an inability to manage known risks, additional costs and delays. For multiple reasons described herein,* ***P&M was completely overwhelmed in trying to manage Campus Plan Projects*** *-- in particular, the two largest of these projects, the D2O Storage Facility and Auxiliary Heat Steam Plant ("AHS") which were the "pilot" projects for this new acting model. (our emphasis)*

[82] Transcript Volume 14, page 93-94
[83] Transcript Volume 14, page 105
[84] Transcript Volume 15, page 22
[85] Tab 4 3, Schedule 'l Staff-072, Aftachment 4, Page 2

5.15 Energy Probe questions what took OPG so long to overhaul its procedures for the P&M group, particularly in light of the dollar amount of work the organization was tasked to oversee and the findings from the Modus audit reports.

5.16 And finally, while OPG says these types of issues are behind, it's own evidence shows that the company is *still* experiencing cost overruns on recent projects.[86] According to OPG, on just three projects, it's seen cost overruns of $20.2 million, or about 23%.

Chart 1

Project No.	Project Name	Total Project Estimate - Last BCS (M$)	Total Project Estimate - Current BCS (M$)	Variance (M$)
31552	Condenser Circulating Water and Low Pressure Service Water Travelling Screens Replacement	24.4	37.6	13.3
40976	Pickering B Fuel Handling Reliability Modifications	37.3	43.0	5.7
66600	Machine Delivered Scrape	24.9	26.1	1.2

5.17 Energy Probe would also highlight that the AHS – and other early DRP projects, such as the Operations Support Building – would have initially fallen under the CRVA and, as such, the Board would have been allowed a detailed prudence review of any cost overruns. But, because of reclassification out of the DRP, those projects are, in essence, shielded from such a review. OPG has provided its reasoning for why those projects should have been reclassified. We don't have any specific comments on the company's reasoning, but do want it made clear that the reclassification appears to have been a beneficial one for the company, given what ultimately occurred regarding double-digit cost overruns and years-long schedule delays.

5.18 Ultimately, many of the management failures that occurred on the AHS project – and the subsequent cost overruns that were incurred as a result of those failures – were also experienced on projects like the Operations Support Building (OSB), which also fell under the management of the P&M organization. Energy Probe supports Board Staff's proposal that the

[86] Exhibit L, Tab 4.2, Schedule 2, AMPCO 20, page 2

Board should approve some level of rate base disallowance, particularly on the AHS and OSB projects, among others overseen by the P&M organization.

6. Benchmarking of Nuclear Operations and Stretch Factor

Issues:

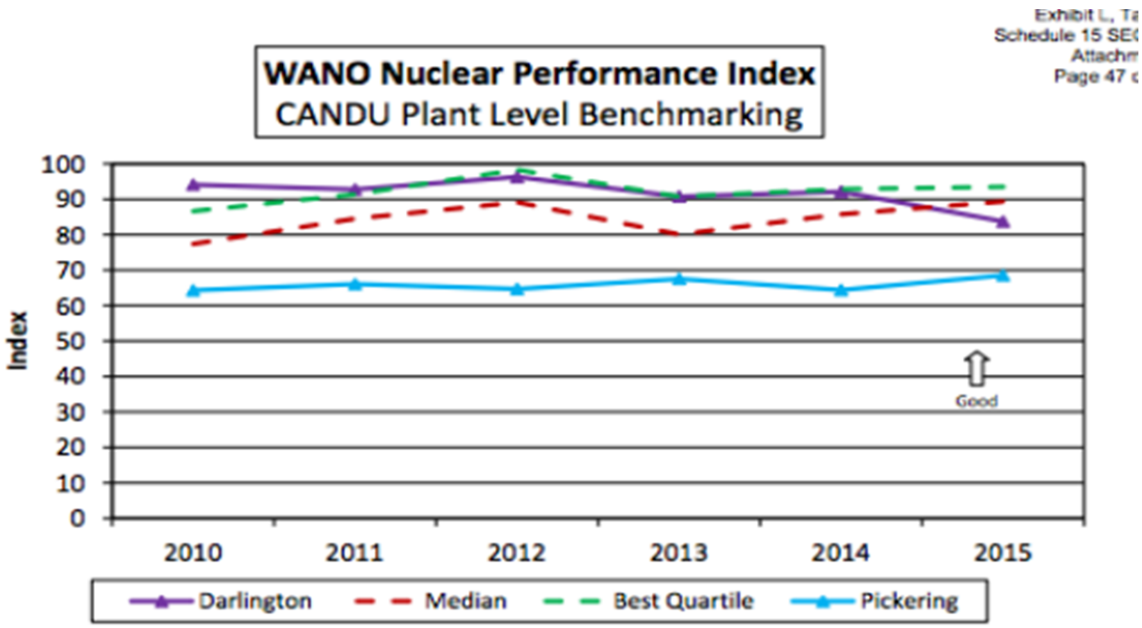
6.2 Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?
11.3 Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

6.1 According to OPG's own benchmarking studies, the company is performing worse than many of its peers in the nuclear industry on many of the most important performance metrics. As such, Energy Probe believes the Board should apply a higher stretch factor of 0.6% and apply it to both OPG's operating and capital costs. There's no reason why Ontario ratepayers should continue to pay rates to a nuclear operator that fails to obtain, and maintain, top quartile status in its own benchmarking studies. Energy Probe will focus on four key metrics from OPG's benchmarking studies:

- WANO Nuclear Performance Index
- Forced Loss Rate (FLR)
- Unit Capability Factor (UCF)
- Total Generating Costs per MWh (TGC)

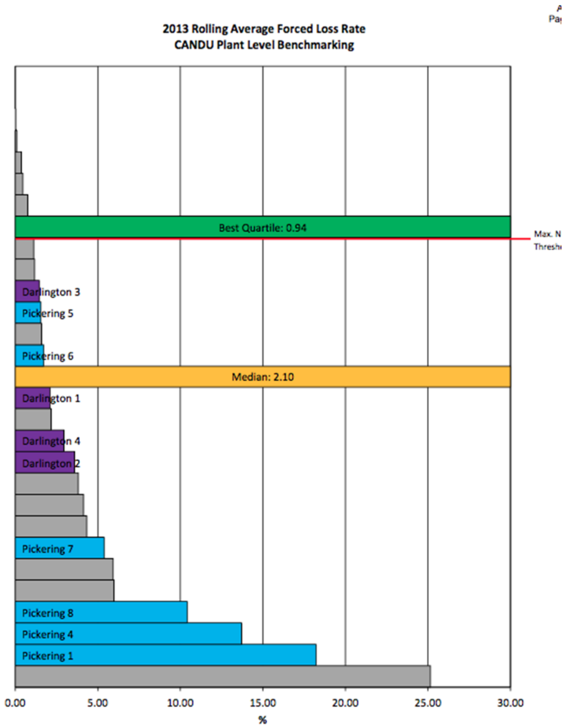
6.2 WANO. Looking at both the 2014 benchmarking report and the 2016 benchmarking report, it's clear that OPG now ranks more poorly to its peers than it did in the past. In 2013, one of the four units at Darlington posted top quartile performance and three units were better than the median, while in 2015, no unit achieved a top quartile ranking, while one unit had fallen below the median. At Pickering, one unit achieved better-than-median performance in 2013, while all of the units had fallen below that threshold in 2015.

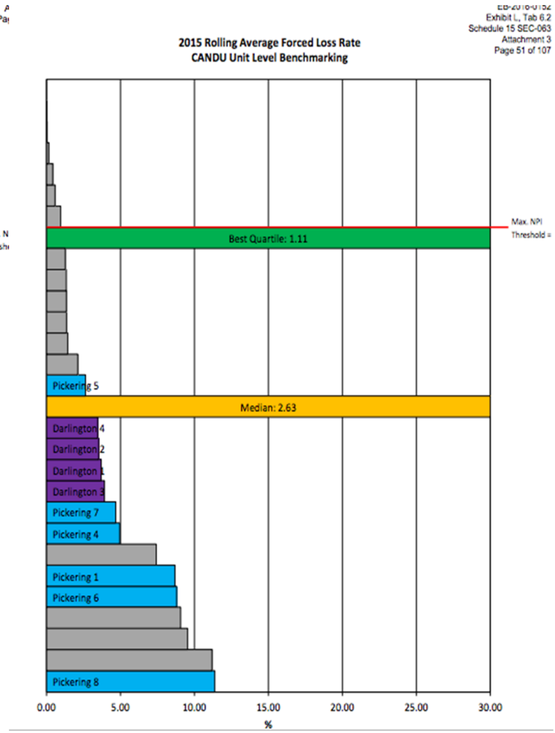
6.3 By 2015, Darlington as a whole had fallen below the median performance, although it historically performed at or above that level. Pickering, meanwhile, saw the gap between its ranking and the median level increase from 2010 to 2015.[87]



6.4 FLR. In 2013, one of the four Darlington units and two of the six Pickering units posted better-than-median results. In 2015, all four Darlington units had slipped below median, while only one unit at Pickering retained above median performance. And while Pickering has, on average, closed the gap between the median level of performance, that gap has grown wider for Darlington.[88]

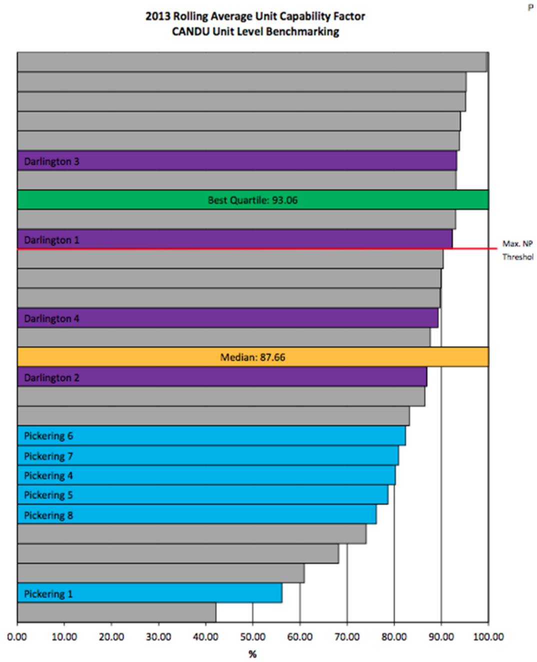
[87] Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 3, Page 46 and Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 1, Page 43
[88] Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 3, Page 51 and Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 1, Page 48

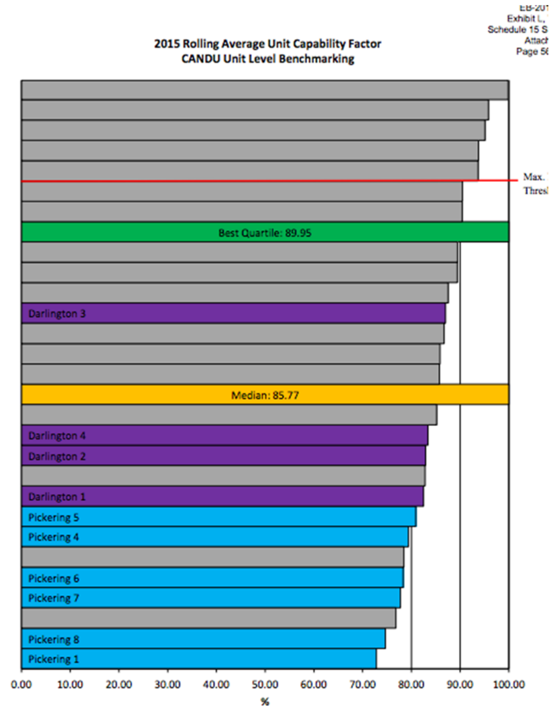




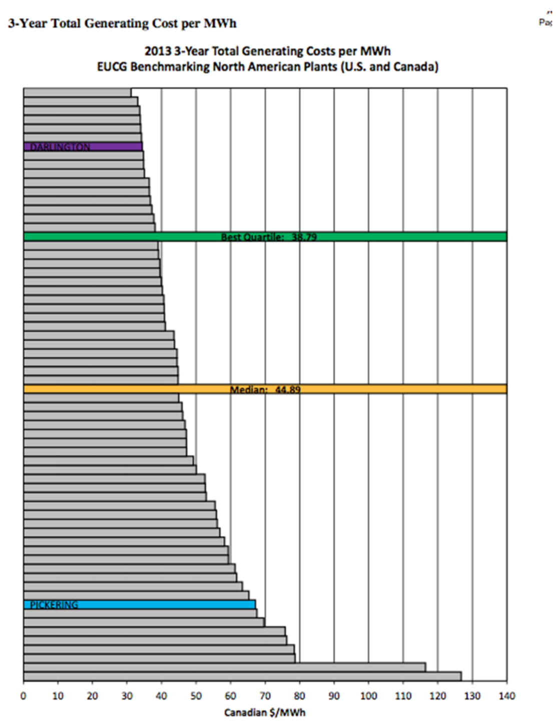
6.5 UCF. In 2013, one Darlington unit performed in the top quartile, while just one unit fell below the median. In 2015, three units performed below median and not a single unit was in the top quartile. Pickering, meanwhile, saw two of its six units come in dead last in 2015.[89]

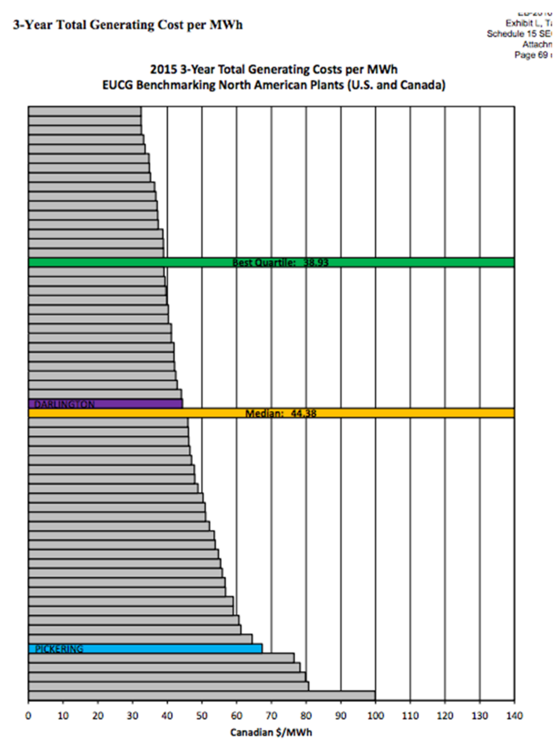
[89] Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 3, Page 56 and Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 1, Page 53





6.6 TGC. In terms of value for money, Darlington's TGC performance slipped from the top quartile in 2013, to just slightly above median in 2015. Pickering, meanwhile, remains one of the highest cost nuclear generators in the sample group.





6.7 OPG has repeatedly tried to explain away this poor performance. In regards to Darlington, OPG called 2015 a "unique year", citing the Vacuum Building Outage (VBO), among other problems.[90] OPG's argument is that VBOs are unique to CANDU reactors and, when undertaken, dramatically reduce output and, as such, hurt the company's benchmarking metrics compared to other nuclear reactors.

6.8 Yet, while Energy Probe would agree that VBOs are unique to CANDU reactors, we believe their impact on benchmarking metrics shouldn't be ignored. In fact, in years when a VBO doesn't show up in the three-year average, one could argue that the reliability metrics of CANDU reactors are overstated, given that VBOs are an essential operating component to CANDU reactors. Other nuclear technologies carry their own differences that OPG makes little effort to acknowledge when they make CANDU reactors look better on benchmarking metrics.

6.9 OPG also cited the failure of the PHT pump motors as another reason why performance at Darlington has gotten worse in its benchmarking studies. Yet again, we believe that these are standard mechanical failures that plague all nuclear reactors in one way or another and shouldn't provide OPG with a free pass on its slipping benchmarking metrics. OPG's argument is, essentially, that my car ran great last year if you ignore that time the wheel feel off.

6.10 We discussed Pickering at length above, but want to reiterate that, while OPG is happy to cite the fact that the plant is a first generation CANDU reactor and shouldn't be held to the same standard as other nuclear reactors, we find that argument lacking. If OPG can't find a way to move Pickering into, at least the median level of performance, Energy Probe questions why the plant should continue to remain in operation.

6.11 Worse still is that OPG doesn't even come close to hitting its own targets for benchmarking performance. Looking back at the forecasts made in EB-2013-0321 for benchmarking metrics to the actuals filed in response to an undertaking, it's clear that OPG failed to hit almost every target (red boxes are metrics that missed OPG's forecasts).[91]

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[90] Transcript Volume 6, page 126
[91] Undertaking 14.4 and Exhibit F2 Tab 1 Schedule 1 Page 15

	2013	2014	2015	20132	20143	20154
	Pickering	Pickering	Pickering	Darlington	Darlington	Darlington
WANO	67.5	64.4	68.5	90.8	92.1	83.7
FLR	9.78	10.88	2.83	5.25	1.53	5.1
UCF	73.71	75.28	79.35	82.92	92.09	76.86
TGC	69.62	68.78	63.91	42.31	39.63	52.32

6.12 And according to OPG's evidence, ratepayers can't expect to see the company's benchmarking metrics improve in any meaningful way in the next three years compared to the actuals in 2013-2016.[92] In many cases, the metrics will get worse. Yet, OPG has already provided a list of excuses for why these metrics will fail to reach top quartile performance going forward.[93]

6.13 Energy Probe fails to see the value of benchmarking if OPG simply looks for a growing number of reasons why it can't match the performance standards of nuclear plants. Through this hearing, OPG cited VBOs, the failure of PHT motors, the DRP and the early design of some of its nuclear reactors, among others, as excuses for why it has in the past performed below median and will continue to do so in the future. Every nuclear plant has its own quirks, yet the other plants still find ways to outperform OPG on a number of key performance metrics. For Energy Probe, that's a telling story.

6.14 Nevertheless, OPG maintains that the Board should only apply a 0.3% stretch factor on its operating costs. That level of stretch factor places it in the middle of the pack on the range of stretch factors – with 0% being applied to the most efficient utilities and 0.6% to the most inefficient. Yet, even OPG's own evidence shows that a more appropriate stretch factor would be closer to 0.45%.[94]

6.15 For Energy Probe, the most compelling argument for a higher stretch factor comes from OPG's most recent benchmarking study. OPG currently ranks 12th out of 13th in the Three-Year Total Generating Cost benchmark. That is the same level it was at in 2010 when it ranked 12th out of 14th, meaning that over the last five years OPG has shown no noticeable improvement in lowering the cost of its output and providing greater value for ratepayers.

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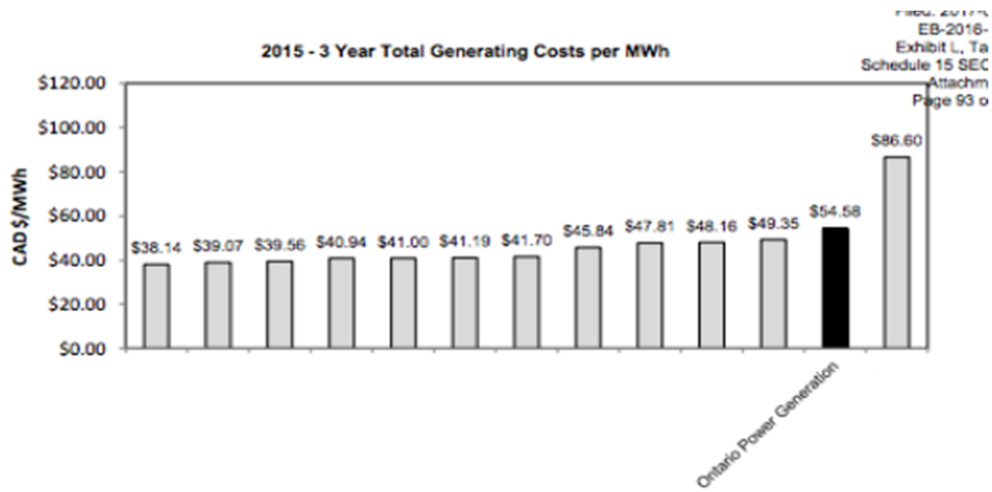
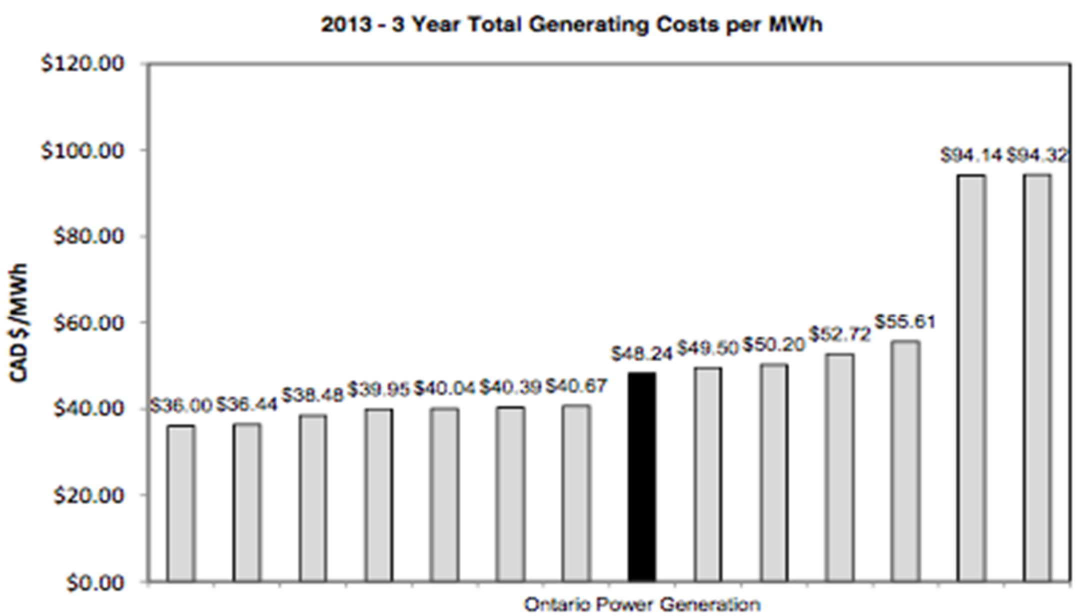
[92] Exhibit F2, Tab 1, Schedule 1, Page 15 of 22
[93] Transcript Volume 14, page 22-26
[94] Transcript Volume 6, page 129





6.16 Furthermore, OPG's TGC metric for Darlington, on a "unnormalized" basis will get significantly worse in the coming years, jumping from $48.09 in 2016 to an expected value of $64.36 – marking a near 34% increase[95] To mask that figure – which OPG says is simply a result of the DRP – OPG has introduced a "normalized" figure. Yet, OPG's own benchmarking experts never signed off on that metric and, in a report on it, clearly laid out a number of its concerns with OPG's approach. They concluded that while the normalization figure was "logical, reasonable and easy to understand," the company should also look at a "more strongly

[95] 2016-0152 Exhibit F2 Tab 1 Schedule 1 Page 15

supported and conventional approach." The benchmarking experts didn't conclude that OPG's method was the best one available and should be adopted by the Board. Energy Probe fails to see why the Board should accept OPG's "normalization" approach when it's own benchmarking experts failed to do so.

6.17 OPG is also proposing to exclude as much as 25% of its annual operating costs from its stretch factor.[96] A large portion of those excluded costs include operating costs for project and outage activities. Summing those costs from 2018-2021 (the stretch factor would first kick in in 2018), that amounts to more than $1.9 billion in spending that, according to OPG, it simply can't find any way to find efficiencies within that budget. OPG's reasoning is that each one of these projects is a "unique endeavour" that does "not lend themselves to that type of gains."[97]

6.18 And yet, OPG's own witness described at length of number of ways in which the company has improved its performance during planned outages.[98] For example, OPG described how it found ways to improve its scaffolding operations during planned outages, which has helped shave days off of those activities. The company also found ways to replace its single fuel channels more efficiently, which has helped shave a week off of planned outages. Put simply, the argument that OPG can't find any savings in its project and outage activities directly contradicts comments from OPG's own witnesses.

6.19 Energy Probe also believes the stretch factor should apply to OPG's capital spending. The most compelling reason why that should be the case is it's in-line with how the Board regulates other utilities and Energy Probe sees no compelling reason why OPG should be treated differently.

6.20 The Board most clearly laid out its position on stretch factors and whether they should apply to operating or capital costs (or both) in Toronto Hydro's EB-2014-0116 application.[99]

> ***The OEB has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach.*** *While the Application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE*

[96] Exhibit F2 Tab 1 Schedule 1 Table 1
[97] Transcript Volume 6, page 135
[98] Transcript Volume 12, page 143
[99] EB-2014-0116, Decision and Order, December 29, 2015

> *is the requirement to continue to make productivity improvements. As discussed later in this Decision, the OEB is concerned that the Application does not contain enough productivity incentives. Application of the stretch factor to the C factor is one way to remedy this deficiency.*

6.21 When asked why the stretch factor shouldn't apply to its capital spending, OPG reasoned that its capital budget is comprised of a number of "discrete projects",[100] which aren't repetitive like those of distributors (according to OPG). OPG also claimed that it "always has more projects than we have budget" and that alone provides it with more than enough of an incentive to be as efficient as possible.[101]

6.22 OPG then went on to say that, unlike its hydroelectric business, its nuclear revenue is 100% variable and doesn't have any production variance accounts. When questioned about the mid-term production review, which clearly offers OPG protection from its production forecasts, the company merely said "there's none currently in effect."[102] Yet, the company is asking for one going forward and, at the same time asking for its capital budget to be exempt for a stretch factor because its revenue on the side of the business is 100% variable. We fail to see how those two comments align with one another.

6.23 Furthermore, OPG's own benchmarking metric that measures value-for-money – the Total Generating Cost metric – includes both capital and operating costs. Yet OPG finds it reasonable, when applying its stretch factor, to exclude capital costs even though they are fully one half of the equation in one of its key value-for-money benchmarking metrics and critical to the company's determination of its stretch factor. Again Energy Probe fails to see why that is reasonable.

6.24 OPG is also set to embark on an aggressive capital spending plan, not including the billions of dollars being spent on the DRP, compared to the company's previous application.[103] Energy Probe is concerned that OPG wants to spend more money on its capital program, but then ask this Board to exclude that increased spending from its stretch factor. We fail to see how that's a good proposition for ratepayers.

[100] Transcript Volume 6, page 135
[101] Transcript Volume 6, page 139
[102] Transcript Volume 6, page 141
[103] Undertaking J 14.1

6.25 Worse still, looking at just non-fuel operating costs, both Darlington and Pickering are firmly in the bottom quartile in its own benchmarking study.[104] So, if OPG were follow its own logic and use only operating cost benchmarks to set its stretch factor, it would clearly be higher than 0.3%. But OPG, again, says the CANDU design means it will always have higher operating costs than other nuclear plants and so that benchmarking metric should be, largely, ignored.

6.26 To recap. OPG is asking for a lower stretch factor on its operating costs than its most recent benchmarking studies show is appropriate. It's then proposing to exclude about 25% of its operating budget from its stretch factor – an amount totalling more than $1.9 billion on project and outage costs alone. It then also wants to exclude capital spending from the stretch factor, even though the Board typically includes it the stretch factor for other custom IR applications. And finally, the metric that OPG used in order to set its proposed stretchmark of 0.3% includes both operating and capital costs, but OPG still doesn't think it's appropriate to include its capital budget in its stretch factor proposal.

6.27 Energy Probe doesn't consider OPG's proposal at all in line with offering value to its customers and becoming a best-in-class generator.

7. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS: HYDROELECTRIC

Ref: London Economics International LLC Report. "Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry", February 19, 2016 ("LEI Report")
Pacific Economics Group Research LLC. "IRM Design for Ontario Power Generation", November 22, 2016 ("PEG Report")
Energy Probe. Note on Data Aggregation, February 28, 2017 ("Note")

7.1 Energy Probe's final submissions on this Issue address the determination of the appropriate Total-Factor Productivity ("TFP") growth rate for the forthcoming incentive-regulation ("IR")

[104] Exhibit L, Tab 6.2, Schedule 15 SEC-063, Attachment 3, Page 74 of 107

regime in hydroelectric generation. Energy Probe includes in these submissions its Note on Data Aggregation that formed part of its Compendia for the cross-examinations of LEI (on March 20, 2017) and PEG (on March 23, 2017).

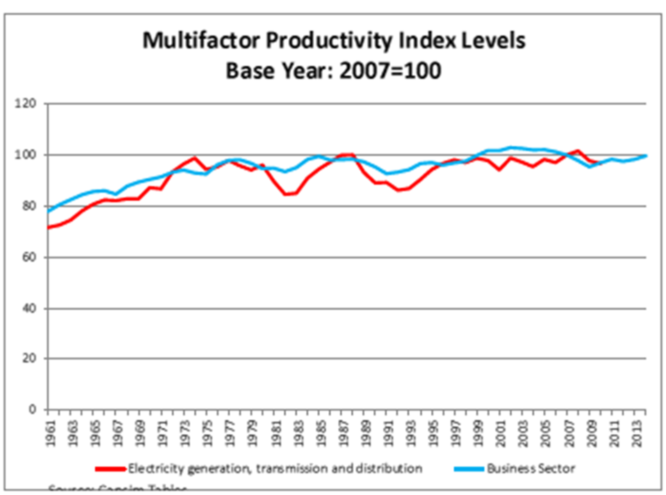
TFP Growth Rates in the Canadian Business Sector

7.2 Energy Probe submits that a baseline or reference point can assist the Board in evaluating the experts' conclusions. In this regard, there are independent statistics of the long-term TPF growth rate derived from Statistics Canada's studies of the Canadian business sector and the Electricity sector. Business-sector TFP growth is a useful benchmark because it includes both regulated and non-regulated sub-sectors and the former would, as a whole, be expected to be lower than the latter.

7.3 In Interrogatory #31 to LEI, Energy Probe submitted the following graph of Statistics Canada TFP levels for the Canadian business sector (for the period 1961-2013) and for the Electricity generation, transmission and distribution sector (1961-2010, since terminated).

7.4 The average annual TFP growth rate was 0.48% for the Canadian business sector for the period 1961-2014. On inspection of the graph, PEG's expert Dr. Lowry opined that it displayed a long-term trend in TFP and that the most recent 10-year period was "off-trend".[105]

7.5 It is noteworthy that for most of the 1961-2010 period, TFP levels in the Electricity sector were below those of the business-sector as a whole. This lower productivity performance may be one indicator of the need to stimulate productivity growth in hydroelectricity generation.



7.6 PEG reported hydroelectric TFP growth rates for the years ending 1996-2014. In those years, the average annual TFP growth rate in the Canadian business sector was 0.21%.

[105] Transcript, Volume 11, cross-examination of Dr. Lowry, Thursday March 23, 2017, at p38.

7.7 LEI reported hydroelectric TFP growth rates for the years ending 2003-2014. In those years, the average annual TFP growth rate in the Canadian business sector was -0.26%.

7.8 In these study periods, Canadian business-sector TFP growth had diverted from its long-term trend of 0.48% per annum. Accordingly, limiting a study of Canadian business-sector productivity growth to the study periods adopted by the experts in this case would produce incorrect results for the long-term trend in the business sector.

7.9 This raises the question whether the study periods for hydroelectric TFP growth adopted by the experts in this case are too short to be considered a reliable long-term trend. Doubtless, as both experts have noted, data limitations have constrained their research efforts. Energy Probe suggests only that the length of the study period is an important variable that should be considered along with all other data and analyses that the parties and interveners have put forth.

7.10 Energy Probe expects that TFP growth rates in hydroelectric generation in Canada would, to some extent, be influenced by the same macroeconomic events that shape business-sector TFP. Accordingly, trends in the latter may assist in evaluating proposed trends in the former.

7.11 Indeed, in the Board's Report in EB-2010-0379, it took note of Dr. Cronin's submissions:

> "In the results of his analysis, Dr. Cronin found an increasingly declining trend in TFP over the period 2000-2011. Unlike the sub-interval 2002-2005, over the 2006-2011 period he found widespread negative growth across a broad sample of distributors. Furthermore, Dr. Cronin expressed the view that the impact of the economic recession would primarily be in 2008-2009. … (Report, Appendix A at p.III)

7.12 Energy Probe is of the view that since TPF growth in the Canadian business sector was negative in each year 2006-2009 inclusive, negative TFP growth in those years for any sector including hydroelectric generation cannot be ruled out. The only issue is whether that negative growth constitutes a long-term trend for the purposes of IR.

Energy Probe's Comments on the LEI Report

7.13 In Energy Probe's view, LEI has not demonstrated any "trend" that the Board can rely on, that its data show a high degree of unreported variability, that conventional statistical analysis reveals that its alleged trends are not significant; that LEI's denial of the relevance of statistical testing due to small sample size is incorrect; and that LEI's estimated TFP growth rate is confirmed by an analysis of its unreported sample data which also confirms the absence of a trend.

LEI's "trend regression method" does not produce a trend.

7.14 The LEI Report proposes "a second method of obtaining a numerical estimate of the TFP growth rate…referred to as the 'trend regression' method; it is a regression-based method that estimates the linear trend of the TFP Index values over the study period timeframe."[106]

7.15 Energy Probe submits that LEI's trend regression analysis produces, at best, a bifurcated trend similar to that observed above in regard to Canadian business-sector productivity. Energy Probe further submits that LEI's reliance on an estimated regression coefficient masks the important differences between the two sub-periods shown below.

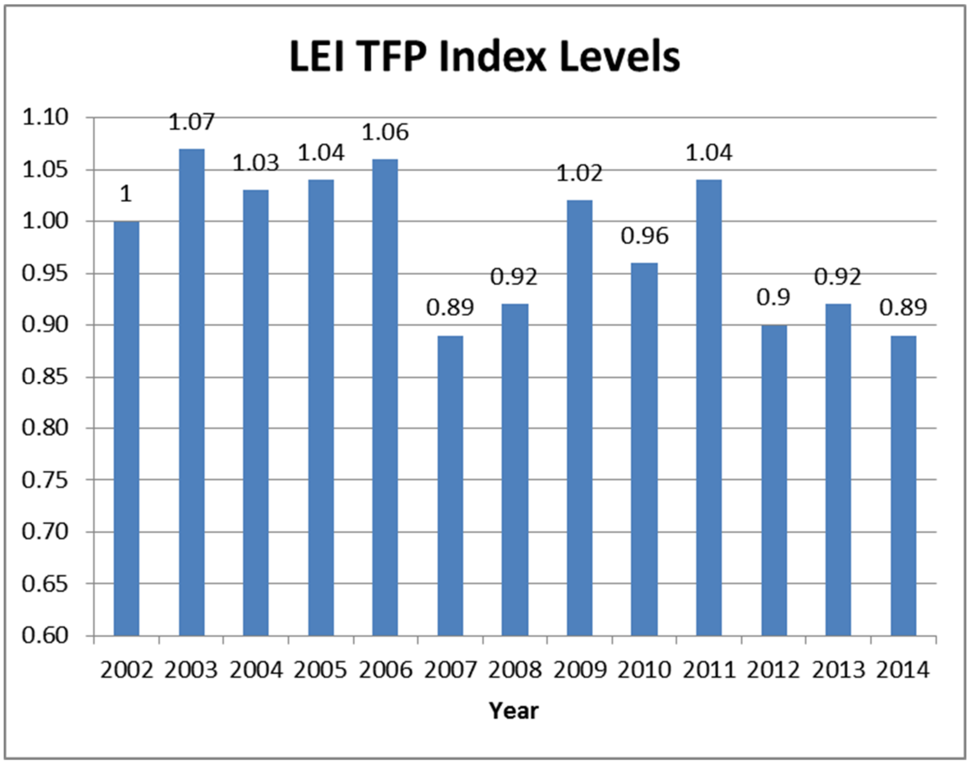
7.16 Note that LEI's focus here is on TFP Index levels, not TFP growth rates. Figure 29 of the LEI Report provides the estimated equation of a linear regression of the natural logarithm of its TFP Index values against time in years for the period 2002-2014, i.e. 13 years in its regression data; the estimated coefficient of the time variable is -1.18%.

7.17 In Undertaking J10.2, Energy Probe requested that LEI provide the usual statistical results that computer-based regression analysis programs typically provide in order to evaluate regression analyses. As provided in greater detail in Appendix A, that summary information indicates that, based on 13 data points, the t-statistic for the -1.18% estimated time coefficient is -2.8. Based on a conventional test of statistical significance, this coefficient estimate is significant at the 5% level.

[106] LEI Report, at p.15.

7.18 However, the indicated coefficient of determination (R-Square) is approximately 42% which means that the progression of time over the sample period explains only 42% of the variation in the natural logarithm of TFP Index levels. Considering that LEI's regression is a time-series regression, this result is unexpectedly low.

7.19 Energy Probe has used the information on TFP Index levels that LEI provided in response to Board Staff Interrogatory #246 to create the bar chart shown below of LEI's calculated Index levels over time.[107]



7.20 On inspection, it is clear that LEI's trend regression equation hides as much as it reveals about the relationship between TFP Index levels and time. To be sure, the index levels toward the end of the period are lower than those at the start.

7.21 However, there appear to be <u>two</u> trends. The bar chart below shows that LEI's TFP Index levels were generally rising in the 2002-2006 sub-period. The average index level for those years is approximately 1.04. A large, and unexplained, decline occurred in 2007, and index levels from 2007 to 2014 averaged only 0.94.

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[107] Exhibit L/Tab 11.1/Schedule 1 Staff-246/Attachment 1

7.22 In other words, there are two distinct sub-periods in LEI study period: 2002-2006 and 2007-2014. LEI's estimated regression coefficient of -1.18% may be statistically significant, but it obscures the presence of these two distinct sub-periods.

7.23 It is noteworthy that LEI provides no discussion of, or explanation for, its falling Index levels in the second sub-period. Had it advanced a reason to think that those declining productivity levels constitute a <u>permanent</u> change in the long-term trend, then that reason could be evaluated on the merits.

7.24 In Energy Probe's view, the only trend that LEI's "trend regression" analysis has identified for its study period closely matches the TFP patterns observed in the Canadian business sector over the same period. Thus, LEI's alleged trend is not an historical trend, let alone a trend that could be expected to prevail in the future.

LEI's "average growth" method does not produce a trend

7.25 LEI adopts the Chained Fisher Ideal Index (report, Fig 4, p.14) and states that its "average growth" method "calculates the year-on-year changes in its aggregate TFP Index and then takes the average of the resulting growth rates over the course of the study period" (LEI Report, p.14). [108]

7.26 LEI reports its year-on-year changes in its aggregate TFP Index in Figure 27 of its Report. In response to Energy Probe's request for Undertaking JT3.24, LEI presents these year-on-year changes together with certain summary statistics in the accompanying chart.[109]

[108] In its discussion of the "average growth rate" method, LEI states that "a mathematical equivalent can be calculated by (i) taking the natural logarithm of the ratio of the last TFP index value divided by the first TFP index value, and (ii) then dividing the resulting value by the number of annual year-on-year observations between the start and end year." (report, p.14)
Energy Probe disputes LEI's stated equivalence of its two approaches to the average growth method, and notes that LEI does not present any results from applying its alleged mathematically equivalent approach.

[109] LEI provides this chart on p.4 of its response to Undertaking JT3.24.

7.27 In its chart, LEI's calculations of the -1.01% sample mean and the 8.40% sample standard deviation confirm Energy Probe's own calculations of these descriptive statistics from the data in LEI's chart.

7.28 Energy Probe additionally calculated the conventional t-statistic in order to test whether, in light of the variability in LEI's sample data of 12 annual growth rates, the -1.01% average could be statistically insignificant. As confirmed by PEG, the t-statistic for LEI's sample data is approximately -0.42 whereas the level required for significance at the 5% level (2-tailed) is -2.20. Since the former does not reach the level required for statistical significance, the hypothesis that the true population mean growth rate is zero cannot be rejected.[110]

Year	Peer Industry
2002-2003	7.11%
2003-2004	-4.35%
2004-2005	1.58%
2005-2006	1.17%
2006-2007	-16.98%
2007-2008	3.40%
2008-2009	9.61%
2009-2010	-5.85%
2010-2011	7.97%
2011-2012	-14.42%
2012-2013	2.22%
2013-2014	-3.60%
AVERAGE TFP	**-1.01%**
STDEV sample	**8.40%**
STDEV population	**8.05%**

7.29 PEG has further confirmed Energy Probe's understanding of elementary statistics that the sample mean is conventionally characterized as a normally-distributed random variable, and as such, the population mean inferred from LEI's data lies between -9.41% and +7.39% with a probability approximately equal to 2/3.[111] Energy Probe suggests that this range of outcomes is too wide to justify a "trend".

7.30 Energy Probe has charted LEI's 12 TFP growth rates to further illustrate whether that data series exhibits a trend. Its Excel chart below also contains a linear trend line and the estimated equation thereof that Excel calculates.

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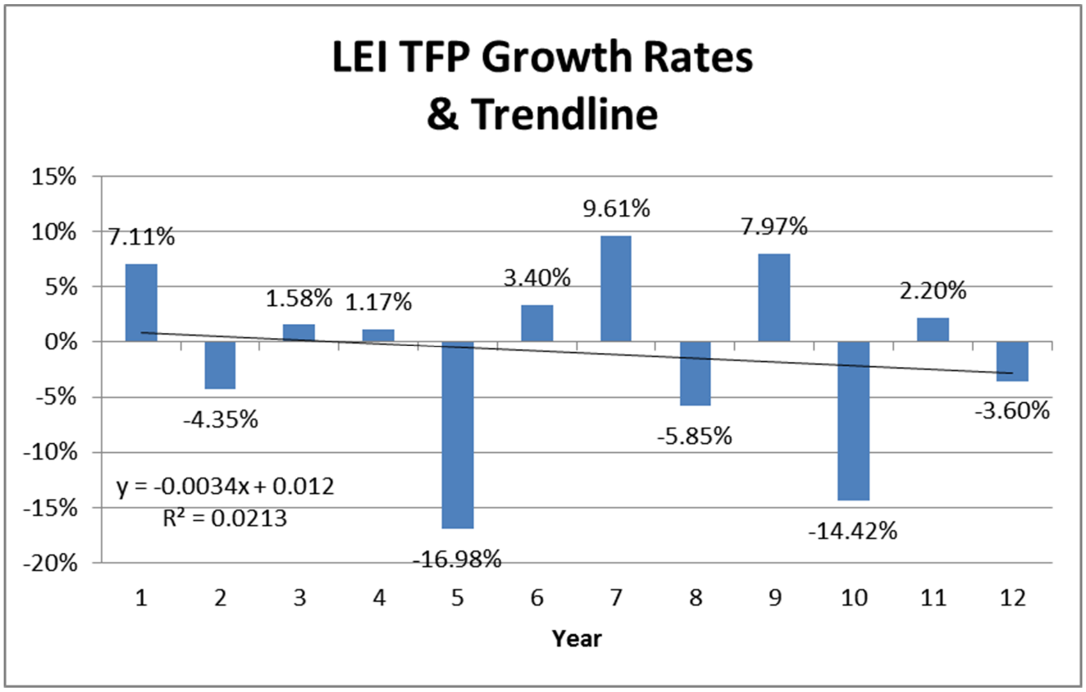
[110] PEG Interrogatory Response to Energy Probe interrogatory (c). Exhibit M2-Tab 11.1-Schedule EP-001-Page 3. While PEG cautions that a small sample can lead to inaccurate results, it does not say that LEI's sample of 12 observations is too small or leads to an inaccurate result. Issues of small sample size are addressed below.

[111] PEG Interrogatory Response to Energy Probe interrogatory (c). Exhibit M2-Tab 11.1-Schedule EP-001-Page 3.



7.31 Energy Probe has analyzed the linear trend line further. Although it has a slope of -0.0034, it is not statistically significant at the 5% level. Due to the variability in the data series, the true slope of the line cannot be distinguished from zero. Energy Probe provides further details of this analysis in Appendix B.

7.32 Energy Probe also notes that the R-Square summary statistic shown on the chart is approximately 2.1%, signifying that only about 2.1% of the variability in LEI's growth rates is accounted for by the passing of time. As a result, there is no obvious time trend in LEI's TFP growth rate data series.

7.33 Energy Probe submits that all that can be inferred from LEI's 12 growth rates is that TFP growth was highly variable over its study period. The range of growth rates is too wide for a "trend", particular the long-term trend of future TFP growth, to be credibly inferred.

7.34 Accordingly, Energy Probe submits that LEI's "average growth method" has not produced any meaningful long-term trend.

Summary of LEI's trend analysis

7.35 Energy Probe suggests that LEI's reported -1.01% average annual TFP Index growth rate should be viewed in conjunction with other measures. Measures of variability such as standard deviation, statistical significance, R-Square and confidence intervals together with the simple charts of LEI's data all point in the same direction, i.e. that neither of LEI's two approaches has identified a trend that is reliable enough for the purposes of IR.

7.36 Energy Probe is of the view that the variability in LEI's data is the principal reason why it has not been able to establish a convincing trend. It may well be, as PEG has suggested, that LEI's choice of "volume" as its output variable is the source of the variability in its growth rate data.[112]

7.37 LEI's arguments that conventional statistical analysis is inapplicable to its data are unconvincing. This is especially so for its suggestion that "small sample size" renders standard deviations and conventional one-sample t-tests invalid. In its cross-examination of LEI, Energy Probe handed up a tabulation of the distribution of the Student's t-statistic, which showed that t-tests are possible and accurate for sample sizes as small as 2, so LEI's sample of 12 annual TFP growth rates is not too small for conventional statistical testing.

7.38 Apparently LEI had no reservations about using the 13 observations in its trend regression analysis which, as noted above, produces a statistically significant coefficient estimate. So its criticism of Energy Probe's use of LEI's 12 TFP growth observations for standard deviation and statistical testing seems overdone. Moreover, LEI cannot simultaneously maintain that its sample size is large enough to warrant confidence in its arithmetic average annual TFP growth rate of -1.01%, yet is too small to justify other simple statistical measures such as standard deviation and R-Square.

7.39 As Energy Probe stated in its Note on Data Aggregation, the result of a conventional test of statistical significance should not, in itself, be dispositive in regulatory proceedings. Energy Probes submits only that the Board should take the results of such tests into consideration in reaching its decision.

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[112] Transcript, Volume 11, cross-examination of Dr. Lowry, Thursday March 23, 2017 at lines 22-28.

LEI's company-level growth rate data do not exhibit a trend

7.40 As stated in its Note on Data Aggregation, Energy Probe sought to replicate LEI's average annual TFP growth rate of -1.01% from the growth rates of the individual companies in its sample. In this sense, it was attempting to replicate LEI's principal result by a different approach, one that LEI had not followed.

7.41 In response to Energy Probe's Undertaking JT3.24, LEI provided the following growth rate data in hardcopy for the 16 companies in its study period 2003-2014.[113]

Chart 1 - TFP index Growth - Average growth method (%)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	AVG
OPG	-3.2	5.9	-5.3	1.1	-4.2	11.1	-1.7	-16.7	6.6	-6.6	6.1	0.8	**-0.49**
AB Power	33.6	-27.0	0.4	-37.4	-82.8	50.2	97.0	-51.4	-12.0	-19.2	72.5	-40.9	**-1.41**
AP Power	50.7	-17.7	-15.2	-7.0	-5.2	-12.1	19.6	-6.4	-3.3	6.2	13.8	-33.3	**-0.82**
Ameren MI - Union	-8.8	30.4	2.7	-76.7	46.8	6.2	2.6	8.0	-6.1	-26.6	21.0	-23.7	**-2.02**
Avista	-14.8	6.5	-5.9	12.4	-11.3	3.9	-3.2	-6.9	24.3	-9.6	-14.2	15.1	**-0.30**
Duke	21.5	-26.7	8.8	-12.8	-6.6	4.7	-1.3	-2.9	-10.8	-6.3	26.5	-3.1	**-0.76**
GA Power	50.7	-35.7	8.0	-35.0	-18.2	-36.5	110.3	-22.2	-13.4	5.8	65.1	-38.1	**3.41**
ID Power	1.7	-2.9	2.8	39.4	-40.4	11.0	16.3	-10.0	40.6	-32.6	-34.5	9.4	**0.06**
PacifiCorp	5.5	-16.1	-3.5	36.5	-21.7	0.0	-7.0	8.3	21.4	-4.7	-32.8	20.4	**0.53**
PG&E	10.3	-7.4	14.5	17.8	-61.0	-0.3	9.6	16.1	13.3	-50.1	-2.3	-25.8	**-5.44**
Portland	-1.3	3.3	-9.4	23.2	-14.9	0.1	-1.1	6.2	7.7	-9.8	-14.9	-4.9	**-1.32**
SCE&G	28.9	-12.2	12.2	-26.5	8.0	-13.9	-3.7	0.8	-13.4	6.7	2.5	-28.4	**-3.26**
Seattle	-12.9	-1.1	-7.5	19.1	-4.2	-4.2	-6.9	-2.9	28.3	-9.7	-16.8	17.1	**-0.15**
SEPA	50.2	-10.8	12.2	-58.7	-0.9	-17.2	28.4	14.8	-13.9	-11.4	34.6	-5.7	**1.80**
SoCal Edison	14.2	-13.2	37.2	-2.5	-70.1	2.1	33.5	11.3	9.6	-48.7	-20.8	-24.3	**-5.98**
VA Electric	6.6	-14.3	-20.6	9.5	15.0	-40.5	30.3	19.8	-12.5	48.1	-38.9	-1.7	**0.06**

7.42 There are 192 TFP growth-rate observations in the data. As Energy Probe further discusses in its Note on Data Aggregation (in Appendix C), the arithmetic average annual growth rate thereof is -1.01% and the standard deviation is 26.4 percentage points. In light of the high variability in this sample, Energy Probe finds that the average TFP growth rate of -

[113] JT3.24, p.2.

1.01% is not statistically significant. Indeed, at the 95% confidence level, the true mean lies between +2.75% and -4.76%.[114]

7.43 The right-hand column of LEI's chart labelled AVG contains, for each company, LEI's calculation of the arithmetic average TFP growth rate for 2003-2014. Energy Probe thanks OPG and LEI for their efforts in providing these data, but notes that certain of LEI's AVG calculations cannot be replicated from the company data in the chart itself. This is, for example, the case for OPG, whose reported AVG of -0.49% cannot be obtained from averaging its annual TFP growth rates over the study period shown. Indeed, using the data as provided in LEI's chart, Energy Probe's own calculation of the AVG for OPG is -0.51%.

7.44 PEG has confirmed Energy Probe's calculation for OPG and notes other similar problems in LEI's AVG column. PEG agrees with Energy Probe that they likely arise from LEI's undisclosed round-off procedures. Energy Probe feels that OPG should have reported the same data that OPG used for its own AVG calculations so that its calculations could be replicated exactly. That OPG has not done so does not disturb Energy Probe's conclusion that the mean AVG calculated from LEI's chart is the same as the mean of its year-on-year changes in its TFP Index discussed above.[115] Thus, LEI's -1.01% average annual TFP growth rate can be calculated in either way.

7.45 As Energy Probe has reported in its Compendium, its own calculations of the AVG's show a standard deviation of 2.37 percentage points; accordingly, the -1.01% mean of the AVG column data is not statistically significant. The associated 95% confidence interval is +2.57% to -2.27%, indicating again that the true AVG growth rate is highly uncertain.[116]

7.46 LEI's sample of 192 TFP growth rates constitutes a large sample. Moreover, Energy Probe's frequency distribution of these data shown below indicates that the sample is approximately normally distributed. Both of these conditions support the valid use of standard deviation and conventional t-testing for significance. Thus, while the statistical analysis of LEI's 192 company-level growth rates confirms LEI's reported annual average TFP Index growth rate of -1.01%, it also supports the view that neither the sample approach nor the analysis of LEI's

[114] Compendium for Cross-Examination of LEI, p.29
[115] Note on Data Aggregation, fn. 5 at p.2.
[116] Energy Probe Compendium for LEI Cross-Examination, p.28

reported growth rates derived above from its aggregate TPF Index, support an inference of a trend.

7.47 Energy Probe submits that LEI bears the burden of showing that its research supports the conclusion that a trend can be identified for its study period and that that trend will hold in the future. LEI has not met either element of this burden, and on this basis Energy Probe submits that the Board should reject LEI's alleged long-term trend TFP annual growth rate of -1.01%.

Energy Probe's Comments on the PEG Report

7.48 The PEG Report concludes that the average annual TFP growth rate for the hydroelectric industry was 0.29% for its study period and that this aggregate growth rate constitutes a long-term trend.[117]

7.49 The only discussion of PEG's research methodology appears to be the following:

> "We gathered historical data on the operations of US investor-owned utilities engaged in hydroelectric power generation. We used these data to calculate indexes of trends in the O&M, capital, and multifactor productivity of each utility in the provision of hydroelectric power generation. Size-weighted averages of those trends were then calculated for the full sample and some subsets." (PEG Report, Exhibit M2, at p.45)

PEG's TPF Index approach does not indicate a trend

7.50 The PEG Reports displays the year-on-year changes in aggregate TFP Index for Capacity in the second column from the right in its Table 3:

[117] The PEG Report refers to multifactor productivity growth ("MFP"), whereas the LEI Report and Energy Probe refer to TFP throughout. TFP and MFP are identical concepts.

Table 3

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1,2]

(Larger Sample)

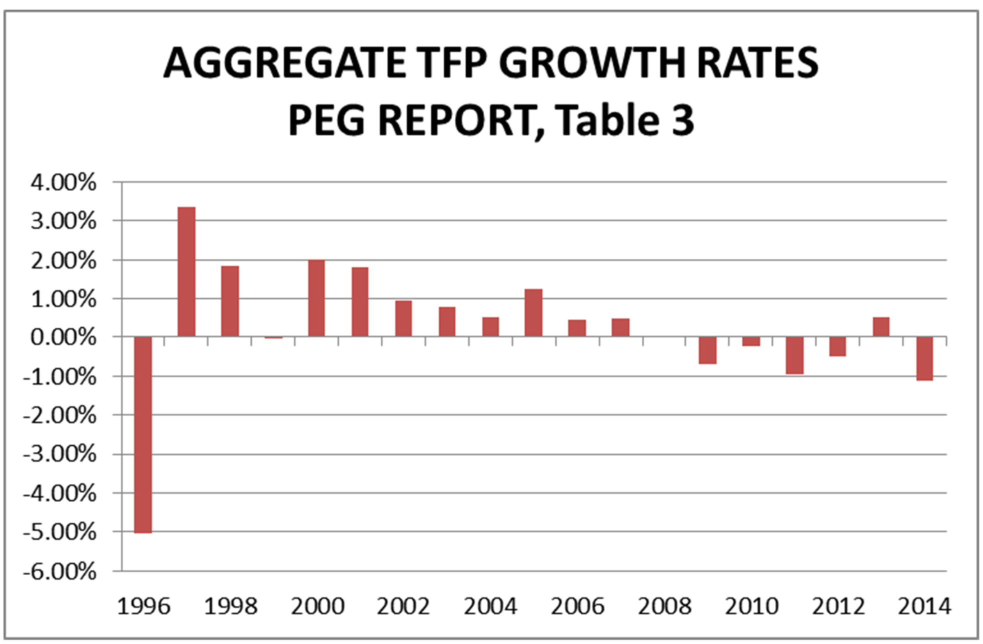
Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1996	-1.14%	1.29%	2.96%	6.88%	3.89%	-5.03%	-2.60%
1997	1.04%	-0.76%	-1.77%	-5.08%	-2.31%	3.34%	1.55%
1998	0.14%	6.75%	-1.21%	-4.56%	-1.70%	1.84%	8.45%
1999	-0.60%	-15.88%	-1.77%	8.21%	-0.58%	-0.02%	-15.30%
2000	0.13%	-10.55%	-1.60%	-11.97%	-1.90%	2.02%	-8.66%
2001	0.38%	-13.19%	-1.70%	5.79%	-1.43%	1.82%	-11.76%
2002	-0.67%	10.04%	-1.64%	-0.16%	-1.61%	0.94%	11.65%
2003	0.12%	17.89%	-1.50%	4.65%	-0.66%	0.78%	18.55%
2004	-0.20%	-9.59%	-1.70%	5.09%	-0.70%	0.51%	-8.89%
2005	0.45%	5.17%	-1.25%	1.89%	-0.79%	1.24%	5.96%
2006	0.20%	0.62%	0.62%	-5.78%	-0.25%	0.45%	0.87%
2007	1.48%	-31.85%	-1.34%	11.12%	0.98%	0.50%	-32.83%
2008	-0.12%	3.15%	-0.92%	2.07%	-0.15%	0.03%	3.29%
2009	0.10%	21.86%	-0.67%	4.82%	0.79%	-0.68%	21.08%
2010	-0.01%	-2.06%	-0.78%	3.57%	0.23%	-0.24%	-2.29%
2011	0.08%	2.38%	0.77%	0.79%	1.04%	-0.96%	1.34%
2012	-0.05%	-20.85%	0.50%	0.11%	0.44%	-0.49%	-21.29%
2013	1.77%	8.36%	1.40%	0.64%	1.24%	0.53%	7.12%
2014	0.72%	-13.04%	2.52%	0.46%	1.83%	-1.12%	-14.88%
Averages:							
1975-2014	**1.40%**	**-0.46%**	**0.15%**	**1.96%**	**0.46%**	**0.94%**	**-0.93%**
1975-1995	**2.49%**	**1.04%**	**0.72%**	**2.38%**	**0.96%**	**1.53%**	**0.08%**
1996-2014	**0.20%**	**-2.12%**	**-0.48%**	**1.50%**	**-0.09%**	**0.29%**	**-2.03%**
2003-2014	**0.38%**	**-1.50%**	**-0.20%**	**2.45%**	**0.33%**	**0.05%**	**-1.83%**

[1] Included in LEI but not PEG Sample: Seattle City Light, Southeastern Power Administration.

[2] Growth rates are calculated logarithmically.

7.51 PEG refers to the period 1996-2014 as its "featured study period". PEG's Table 3 above reports that the average annual TFP growth rate for this period is 0.29%.

7.52 Energy Probe charts PEG's reported TFP year-on-year changes in its featured study period below.



7.53 Simple inspection of this chart suggests that there is a trend toward declining TFP growth rates throughout PEG's featured study period. Indeed, based on inspection, PEG's trend appears more supportive of LEI's alleged trend than LEI's own research.

7.54 However, PEG does not regard this observed pattern of generally-declining growth rates as a trend. Rather, PEG relies on the arithmetic average of the TFP growth rates it has calculated. As shown in Energy Probe's chart, PEG's annual aggregate TFP growth-rates are generally positive in the 1997-2008 period and generally negative thereafter. The PEG Report provides no discussion or explanation why these two sub-periods differ. Apparently, all that matters is the 0.29% annual average that PEG has calculated.

7.55 The PEG Report does not provide any measure of variability of its reported TFP growth rates. In response to Energy Probe's Interrogatory #1(d), PEG confirmed that the standard deviation around its 0.29% estimate was 1.71 percentage points. In response to Energy Probe's Interrogatory #1(g), PEG calculated the associated t-statistic as 0.73 and concluded that since it was below the level of 2.1 required for statistical significance, the null hypothesis that the true mean is zero could not be rejected.[118]

7.56 Energy Probe has additionally calculated the 95%-confidence interval for PEG's estimated average is 0.29% +/- 0.824%. That is, the true population annual TFP growth rate lies in the range +1.114% to -0.534% with a 95% probability. On this basis, PEG's estimated average growth rate is highly uncertain.

7.57 Hence, applying the same criteria to PEG's reported results as it applied to the LEI Report, Energy Probe submits that the PEG Report has not identified a trend.

7.58 It appears that PEG's reported annual growth rates follow the same pattern as that shown above for productivity growth in the Canadian business sector. Some unexplained event occurred in or around 2007, and its effects on business-sector TFP persisted for several years.

PEG's company-level growth rates

[118] Exhibit M2/Tab 11.1/Schedule EP-001/p.3 of 3

7.59 PEG calculated individual annual TFP growth rates for each company in its sample. In Energy Probe's understanding, when aggregated by PEG's procedure, these company growth rates produce a sample-wide average that is equivalent to PEG's average annual growth rate of its aggregate TFP Index. However, the PEG Report does not report or discuss its sample of company-level TFP growth-rate indexes.

7.60 As discussed in Energy Probe's Note on Data Aggregation, PEG's "featured sample" of company growth rates consists of 20 companies over the period 1996-2014, so that it has calculated 380 annual TFP growth rates; see Table 2 of the Note.[119] The unreported sample average thereof is 0.088% with a standard deviation of 6.38 percentage points and, in light of the variability of that data, lacks statistical significance.

7.61 PEG then multiplies each company growth rate by its share of industry costs in each year. Table 3 of the Note shows these 380 "weighted" growth rates by company and by year, the unreported average of which is 0.014% with a standard deviation of 0.374 percentage points.

7.62 Finally, in its third round of calculations, PEG sums the weighted growth rates of all the companies by year.[120] These yearly sums are shown in Table 3 of the Note; they are identical to the annual growth rates of PEG's aggregate TFP Index shown in Table 3 of the PEG Report as charted above.

7.63 In its Note, Energy Probe calculates that average of these annual sums is 0.288% with a standard deviation of 1.711 percentage points. Energy Probe notes that these unreported results are precisely the same as PEG's reported result in its Table 3 and as charted above, except that PEG did not report the variability thereof. On the basis of PEG's unreported sample data, Energy Probe finds that PEG's reported 0.29% average is again statistically insignificant with the same wide confidence interval noted in paragraph 7.56 above.

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[119] PEG has confirmed that Energy Probe's figures in Table 2 of the Note are the ones that PEG had calculated. See PEG response to SEC Undertaking J11.2.

[120] In cross-examination, PEG's expert Dr. Lowry confirmed that Energy Probe had correctly identified the procedures that it had used as described in paragraphs 60-62 supra. Dr. Lowry was not asked to confirm Energy Probe's calculations. See Transcript Volume 11, Thursday March 23, 2017, p.39, line 20 -- page 40, line 5.

7.64 Obviously, PEG's data can be aggregated in different ways with very different results. PEG might have aggregated its sample data by simply averaging its 380 unweighted growth rates which, as noted above, produces a sample-wide annual TFP growth rate of 0.088%. This growth rate could be said to describe the average company in the average year in its sample.

7.65 Alternately, PEG might have averaged its 380 cost-share weighted growth rates which, as noted above, produces a sample-wide annual TFP growth rate of 0.014%. This growth rate gives greater weight to companies with higher cost-shares and could be viewed as emphasizing the growth rates of the more mature companies in the sample.

7.66 PEG does not report these other approaches and does not provide any rationale for preferring its 0.29% estimate reported in Table 3 of its Report. As Energy Probe has shown above and in its Note, this estimate is calculated very differently from the two others.

7.67 Energy Probe submits that the PEG Report lacks transparency in certain critical respects and that the Board would have found it helpful if PEG had provided both a fuller discussion of its sample data and also its rationale for recommending it 0.29% TFP estimate in preference to the other estimates that can be derived from that sample.

Comparison of LEI and PEG Reports

7.68 Energy Probe is of the view that neither expert report has identified a historical trend in TFP growth in hydroelectric generation, let alone a long-term trend that the Board can rely on for the purpose of IR. Each expert appears to rely on the simple arithmetic average annual changes in their respective aggregate indexes. They do not report measures of variability in either their Index growth rates or in their company samples.

7.69 Energy Probe does not say that any one method of data analysis, whether descriptive statistics, conventional statistical testing or simple charting, is dispositive. It submits however, that when taken together, all such evaluations point in the same direction, that no long-term trend in hydroelectric generation is apparent. Energy Probe also submits that the experts' reliance on their reported sample means is misleading in light of the unreported variability.

7.70 However, Energy Probe does not say that both expert reports should be rejected. Indeed, it is far from clear that another expert report would produce a different result. Energy Probe submits that the Board consider the relative merits of the two reports. In this respect, there are several differences that the Board could consider.

Length of Study Period

7.71 In Energy Probe's view, the study periods adopted by both experts may be too short to capture the long-term trend in TFP in hydroelectric generation. As seen with the trend in business-sector TFP and as Dr. Lowry testified, the most recent 10-year period deviates from the long-term trend.

7.72 That data limitations have influenced the study periods adopted by the experts is not doubted. However, since TFP reflects both short-run and long-run influences, the shorter the study period, the more likely it is that the results reflect those short-run influences.

7.73 Since PEG's "featured" study period 1996-2014 is longer than LEI's study period 2002-2014, Energy Probe feels that the Board should give more weight to PEG's results.

Sample Composition: Size

7.74 In selecting their company samples, both expert reports propose criteria that result in the inclusion of larger, older utilities. Energy Probe suggests that such samples may not fully meet the requirement for industry-wide TFP growth, especially if, as Dr. Lowry confirmed, PEG excluded utilities with less than $100 million of plant size even if good data were able.[121] Similarly, LEI limited its sample to "peers" of OPG.

7.75 These limited samples lead Energy Probe to suggest that long-term TFP growth rates that the experts have advanced should be regarded as the <u>minimum</u> growth rates on the basis that a more representative industry sample would contain companies with greater opportunities for productive investment.

[121] Transcript, vol 11, March 23, 2017, p. 32, lines 3-9. In addition, Dr. Lowry stated that younger, smaller utilities taking advantage of more recent technologies may or may not have greater opportunities for productive investment than more mature utilities, and he emphasized that opportunities to build and develop hydroelectric facilities in the US are more limited than in Canada, ibid. lines 10-21. Energy Probe doubts that this statement applies to Ontario.

Sample Composition: US Utilities

7.76 Both experts have created samples of US companies. Energy Probe accepts that this is necessary. To generalize the experts' results to Canadian, and particularly Ontario hydro generators for the purpose of IR, assumes either that macro-economic conditions that prevailed in Canada and in the United States over their study periods have no effect on hydroelectric industry TFP growth or that they affect industry TFP growth in broadly similar ways.

7.77 Energy Probe makes the latter assumption. Both experts have documented the downturn in US hydroelectric generation TFP that occurred in the latter parts of their respective study periods. Energy Probe attributes this downturn to the 2008 financial crisis and the lengthy ensuing economic recession affected both countries and their hydroelectric generation industries. In this sense, Energy Probe accepts that the US TFP experience in hydroelectric generation should be accepted for the purpose of determining the productivity factor for IR in Ontario.

7.78 There are differences between Canada and the United States that might be relevant. Dr. Lowry states that opportunities to build and develop hydroelectric facilities in the US are more limited than in Canada.[122] Energy Probe does not view this difference as germane, either to the issue of sample size or the lack of Canadian hydroelectric generators in either expert's sample.

Sample Composition: CoS regulation

7.79 By virtue of their reliance on a sample of US hydroelectric generators for their respective study periods, the TFP growth rates advanced by both expert reports are those achieved under traditional Cost of Service regulation.

7.80 Neither expert report has called attention to the problem of inferring the appropriate TFP growth rate for IR from samples of companies none of whom are regulated under IR. Energy Probe expects that the productivity growth rates that the experts have advanced understate the TPF performance that the hydroelectric generators in their samples would have achieved under IR in their respective study periods. Indeed, the purpose of IR is to stimulate TFP in the industry relative to the TFP that would prevail under CoS regulation.

[122] Transcript, ibid. lines 10-21

7.81 Energy Probe submits that the TFP growth rates advanced by the experts should be regarded as an underestimate of the growth rate that the Board is seeking to adopt in its IR formula.

The TFP Index Approach

7.82 The Board has stated its preference for inferring the appropriate TFP growth rate from a TFP index rather than from an econometric model, and both experts have created TFP indexes. Energy Probe further understands that the Board's general approach is to adopt a single TFP growth rate for all regulated utilities based on an industry TFP index, rather than to determine an individual growth rate for each regulated company.

7.83 However, the Board does not prescribe how the index should be derived. Both experts appear to have implemented the Board's preferred approach by creating indexes of aggregate output and input and growth thereof in each year, and by calculating the aggregate TFP growth rate for that year as the difference between the growth rates of those two indexes.

7.84 However, both experts have calculated their input and output indexes from the corresponding data of the companies in their respective samples. Thus, they might have calculated TFP growth rates for each company in each year and then aggregated in some comparable way to achieve the same result. However, neither report presents sufficient sample data to conduct this check.

7.85 Energy Probe sought to confirm that the two approaches indeed produce the same result by examining the TFP growth rates of the companies in each expert's sample. As indicated in its Note, it confirmed LEI's reported aggregate growth rate of -1.01% by simple averaging of the 192 annual TFP growth rates in its sample of 16 companies over its 12-year study period.

7.86 Energy Probe's Note confirms PEG's 0.29% aggregate TFP Index growth-rate estimate from the 380 observations (20 companies over 19 years) in its sample. Thus, the confirmation of the reported results of each expert's index approach illustrates that the Board's requirement could be met in either way, and that each way is consistent with the Board's preference to avoid assigning an individual growth rate for each regulated company.

7.87 However, on the basis of its much larger sample of annual TFP observations, Energy Probe submits that PEG's TFP results should be given greater weight than LEI's results.

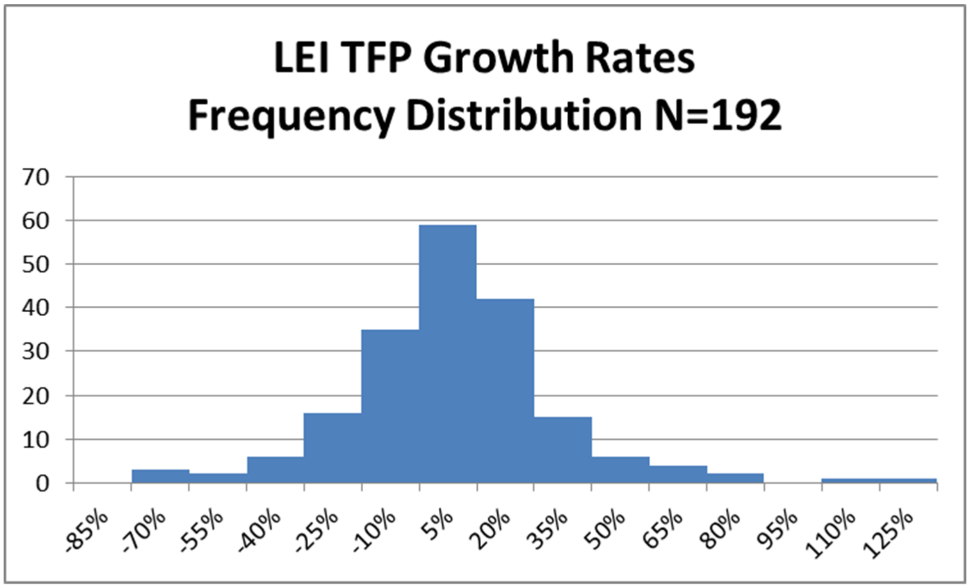
Variability

7.88 The main difficulty that both expert reports display in the identification of trends is variability in the data they have used to create their respective aggregate TFP Indexes. However, this problem is much more pronounced in LEI's report. As shown above, LEI confirmed that the standard deviation around its -1.01% estimate is 8.4 percentage points. For PEG's 0.29% estimate, the unreported standard deviation is 1.71 percentage points, which PEG has confirmed in its response to Energy Probe interrogatory #1(d).

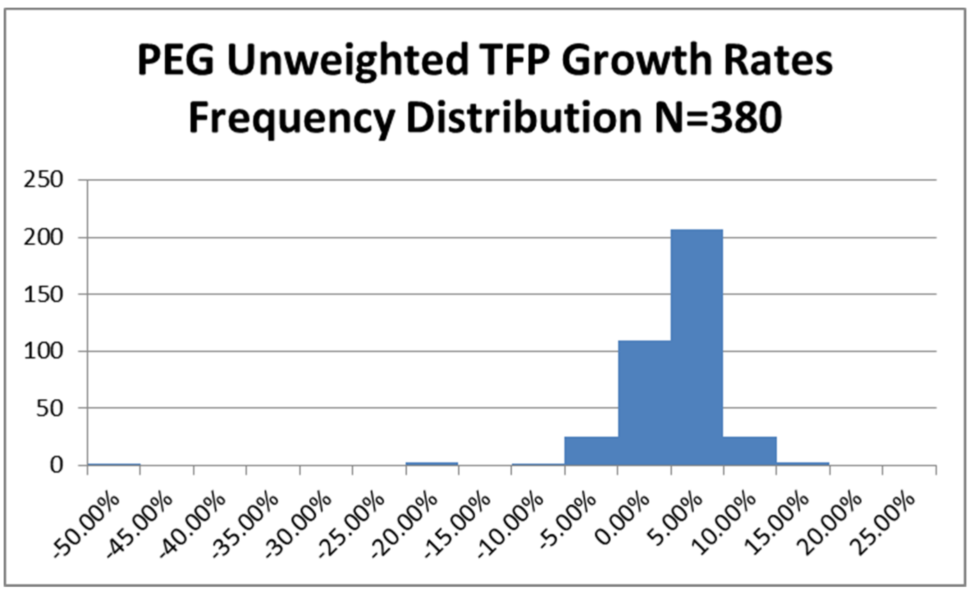
7.89 Table 1 in Energy Probe's Note displays the 192 annual TFP growth rates in LEI's sample data. Without further calculation, Energy Probe has charted the frequency distribution of that data.

7.90 Two points are immediately seen. First, the range of TFP sample growth rates is wide, from -70% to +125%.

7.91 Second, the frequency distribution of LEI's growth rates is approximately normal. Although not necessary for hypothesis-testing, the normal distribution of TFP growth rates supports the claim that the sample mean thereof also follows a normal distribution, hence conventional statistical testing of the significance of the mean is valid.



7.92 Table 2 in Energy Probe's Note displays the 380 annual unweighted TFP growth rates in PEG's sample. The corresponding frequency distribution is presented below.



7.93 Not only is the range of growth rates much smaller than LEI' range, but the distribution is more tightly clustered around the sample mean than is LEI's distribution.

7.94 Energy Probe submits that the much reduced variability in PEG's sample of growth rates is a key finding and confirms the lower variability of PEG's TPP Index growth rates that Energy Probe has shown above.

7.95 In Energy Probe's cross-examination of Dr. Lowry, he stated that LEI's greater variability is a consequence of its choice of volume as the output measure:

> *"…And now to get back to your question, clearly the results are much more variable and it also implies the standard deviation comparisons that Ms. Freyer's results are more variable than ours and that is in big part due – or maybe entirely due to the volume issue."*[123]

7.96 If the Board finds that volume and capacity are, in principle at least, equally valid measures of output, Energy Probe submits that, on the basis of its much higher variability, the Board should reject LEI's alleged annual -1.01% TFP trend and accept PEG's TFP trend.

PEG's various TFP growth rates

7.97 As noted, PEG has reported only one TFP growth rate, its aggregate industry growth rate of 0.29%. However, as Energy Probe has shown, PEG did not report the simple average annual growth rate of 0.088% based on its sample of unweighted growth rates or the 0.014% average of its weighted growth rates. In this regard, Energy Probe submits that Board should consider whether the trend that it seeks for the IR formula is PEG's total- industry TFP trend or the trend that describes the TFP growth of a typical hydroelectric generator given the industry conditions that prevailed over the study period.

7.98 In its Report regarding electricity distributors[124], the Board quoted from its Report in EB-2007-0673 as follows:

> "The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry."

7.99 In Energy Probe's view, the methodology leading to PEG's 0.29% TFP growth rate may provide an unreasonable TFP growth rate in future updatings by the Board. For example, it

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[123] Transcript, vol. 11, Thursday March 23, 2017 at lines 22-28.
[124] OEB. Report of the Board. Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18, 2012 at p.17.

could be the case that future aggregate TFP growth rate in hydroelectric generation would be too large to reasonably expect that any one company could be expected to achieve it.

7.100 However, Energy Probe feels that PEG's estimate is superior to LEI's for the reasons discussed above and is consistent with the positive long-term TFP growth rate in the Canadian business sector, as Energy Probe would expect.

8. CAPITAL STRUCTURE AND COST OF CAPITAL

Issues:

3.1 Are OPG's proposed capital structure and rate of return on equity appropriate?

What level of equity thickness does OPG want and why

8.1 OPG's equity thickness has fluctuated between 45% and 47% since it first came under OEB regulation in 2007. As detailed at length in Board Staff's final argument, the reasons for moves to higher or lower equity thickness over the last decade relate to the perceived "riskiness" – increased or decreased – of OPG's business. OPG's witness, Concentric, provided evidence detailing why it believes the company's risk profile has notably changed and, as such, should retain an equity thickness of 49%. The move from a 45% to 49% equity thickness would increase OPG's potential return on equity over the test period by $114 million on its hydroelectric rate base and $79 million on its nuclear rate base.[125]

8.2 On the hydroelectric side of the business, Concentric notes that OPG's risk profile will remain largely the same going forward "with the exception of regulatory risk."[126] The increase in regulatory risk, according to Concentric, is two-fold. First, the company is moving to a five-year rate-setting period, where in the past it typically operated under a two-year window. And, secondly, OPG is moving towards incentive regulation and away from a more standard cost-of-service form of regulation.

[125] Exhibit L Tab 9.8 Schedule 1 Staff-217 Attachment 1 Table 1 and Exhibit L Tab 3.1 Schedule 2 AMPCO-O16 Attachment 1 Table 1
[126] Transcript Volume 17, page 154

8.3 On the nuclear side of the business, Concentric confirmed that the "execution" risks of completing large and complex capital projects have "increased significantly."[127] Concentric ultimately admitted that the DRP was the biggest driver of increased risk for the company. To a lesser extent, Concentric also noted that OPG is facing greater risks from "emerging safety regulations" and "component degradation." And similar to the hydroelectric business, Concentric noted that OPG's move to a five-year rate-setting plan for its nuclear operations increases risk.

8.4 Concentric also highlighted the significant increase in rate base associated with OPG's nuclear business – notably the in-service addition of Unit 2 of the DRP in 2020. That increase in nuclear rate base will push the nuclear portion of OPG's rate base beyond the level it was at when the Board established a 47% equity thickness.[128] By the end of this rate-setting period OPG's nuclear rate base will account for 51% of the total, up from its current level of 31%[129]

The Standalone Principle Needs Revisiting

8.5 Energy Probe is a firm believer in competitive electricity markets and would, ultimately, prefer less government ownership in the sector – an argument the organization has presented on numerous occasions to this Board. Under that premise, we are supportive of the "standalone" principle and its application to OPG. But Energy Probe feels that the degree of provincial interference in the regulation and operation of OPG means that principle is no longer in force. Establishing a capital structure for OPG based on the standalone principle is flawed.

8.6 First, there's the simple fact that OPG has a direct line of financing from the province through the Ontario Electricity Financing Corporation (OEFC), which, according to that agency's annual report provides "financial assistance to the successor corporations of Ontario Hydro", including OPG. The OEFC has provided OPG financing for the Niagara Tunnel Project, the Portlands Energy Centre and Lac Seul hydroelectric project. The OEFC has also agreed to provide as much as $700 million for the Lower Mattagami project and $800 million for the DRP. Concentric agreed that the OEFC ensures a "ready source of funds...to provide financing to OPG, and they [OPG] don't have to go out to institutions and individuals" to raise capital.[130] The

[127] Transcript Volume 17, page 155
[128] Transcript Volume 17, page 155
[129] Exhibit L, Tab 3.1, Schedule 20 VECC-005, Attachment 1, Table 5
[130] Transcript Volume 19, page 23

Board of OEFC is largely made up of public servants appointed by the province and the Chair is the Deputy Minister of Finance.[131]

8.7 Concentric's response to the OEFC's relationship as OPG's source of financing was that, while the province will go out and raise funds for OPG, investors will be focussed on the "underlying entity's credit metrics, cash flow metrics...that are supporting the credit quality associated with those debt issuances."[132] Just because it's the province raising the funds, it's OPG's financial health – independent of the province – that investors will pay attention to when loaning the company money, according to Concentric. Yet, the reality is a much different picture than the one Concentric is painting.

8.8 For starters, on a standalone basis OPG would be considered "junk" and, if it were to issue debt without the backing of the province – or through the OEFC – then the interest rates it would pay would be significantly higher.[133] In fact, if OPG were considered "non-investment" grade, which is how it is graded on a standalone basis, many investors – such as pension funds – in Canada wouldn't actually be allowed to buy that debt. Provincial support – whether it's explicit or implicit – is the only way in which OPG is, essentially, capable of financing itself.

8.9 Concentric even admitted that OPG would struggle to raise debt using its standalone credit rating and it's only the province's "implicit guarantee" that makes it possible.[134]

8.10 The level of return and equity thickness that OPG would need if the provincial backing were to disappear and it continued to pursue a capital project with a budget as large as the DRP would be dramatically different. Board Staff's witness concluded: "If that was the case, you would see returns way higher than what this Board allows, and equity would have to go way, way high for you to make that feasible."[135] The only reason OPG is capable of financing the DRP is because investors, implicitly or explicitly, know that the province is there to support the company if the project goes off the rails and pushes OPG to insolvency. Ultimately, it's the province's credit rating and support that allows OPG to raise money – and, in fact, raises it for OPG – to move ahead with a capital project as risky as the DRP. OPG's credit rating on its own

[131] OEFC 2016 Annual Report
[132] Transcript Volume 19, page 23
[133] Transcript Volume 19, page 116
[134] Transcript Volume 18, page 47
[135] Transcript Volume 19, page 119

is junk. Energy Probe questions how that can still be considered an "implicit" guarantee and not an explicit one.

8.11 But an "implicit" provincial backstop on debt is just one of the ways that OPG benefits from provincial interference. The province also repeatedly interferes in the operation and the regulation of OPG, notably in the sheer number and value of deferral accounts that, in many cases, directly protect OPG from both construction risk and market risk. As noted above by both capital experts, construction risk is the most prominent risk – to a significant degree – currently facing the company. And yet, the province has largely shielded the company from that risk.

8.12 First, OPG, as determined by legislation passed by its shareholder, is ensured that it will recover all "capital and non-capital costs and firm financial commitments" for investments made in new generation. The province even explicitly named the DRP to ensure there was no confusion around whether it's costs – and any potential cost overruns – should be recovered through the CRVA. Board Staff's witness admitted that without such a guarantee from the province "you probably would not be able to finance" the DRP.[136]

8.13 Secondly, there's the decision by OPG's shareholder to implement "rate smoothing". Concentric admitted that it's unaware of any other utility in its proxy group that is deferring more than $1 billion over a five-year period.[137] While rate smoothing, according to Concentric, increases risk for OPG, no credit rating agency has cited it as an ongoing concern and OPG itself doesn't see it as being a financial detriment (though it does push one of their two financial metrics beyond the level the company prefers). Furthermore, rate smoothing shields OPG's customers from the "rate shock" of a nuclear refurbishment and helps protect the company from the potential demand destruction of such a shock.

8.14 Thirdly, OPG's own shareholder used the legislature to ensure that the company's hydroelectric fleet receives a regulated rate for its generation, thereby shielding the company from the risk of the province's long-term surplus of power. And secondly, its shareholder established the Surplus Baseload Generation (SBG) deferral account, which offers further protection from the province's surplus power.

[136] Transcript Volume 19, page 98
[137] Transcript Volume 18, page 6

8.15 We should also note that it was OPG's shareholder that shielded the DRP from an independent review on its need. At no point will the Board in future proceedings determine that the need for the DRP, and any costs needed to bring it into service, was unnecessary. Given those costs were prudently incurred, OPG is guaranteed to recover all of its spending on the DRP, whether it's a). The most cost effective option to meet future demand compared to alternative sources of generation or b). Unneeded as a result of falling demand.

8.16 From every angle, OPG's shareholder has put in place legislation that protects the company from the many market risks that a merchant generator would typically face. Ultimately, Concentric even agreed that while all of the companies in its study operate in a "highly political environment", no company would "exactly match this type of profile in terms of the role that the government plays in and around its operations."[138]

8.17 And finally, as announced recently in the Fair Hydro Plan, OPG will oversee the financing needed to implement the province's rate smoothing proposal. As part of the financing, OPG will hold tens of billions of dollars of debt in order to smooth the rate impact of clean energy investments made by the province.[139] Energy Probe is unaware of any privately held merchant generator tasked with a similar policy.

8.18 Energy Probe submits that, taken as a whole, OPG is increasingly an arm of the province's energy policy. Upholding the standalone principle, and the increased equity thickness and higher returns that such a principle entails, in the face of such dramatic provincial interference – both in the company's operation and regulation – is a flawed approach. Both of the cost of capital witnesses agreed that, if OPG were to truly operate on a standalone basis, its borrowing costs would be so high that projects like the DRP wouldn't move forward.

Other reasons why a higher equity thickness is inappropriate

8.19 OPG offered no compelling evidence for its argument that its move to incentive regulation is riskier for the company. Energy Probe supports Board Staff's argument that a). OPG's own evidence submits that the company's hydroelectric business is in a steady state and, as such, is

[138] Transcript Volume 19, page 6
[139] https://www.thestar.com/news/queenspark/2017/05/11/electricity-prices-to-soar-after-four-years-says-secret-liberal-cabinet-document.html

“conceptually consistent” with a move towards incentive regulation and b). the Board has explicitly stated in previous decisions that it doesn’t support OPG’s argument that “moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other companies that it regulates.”[140]

8.20 OPG’s cost of capital witness even admitted that it hadn’t looked at other Ontario utilities to see if the move to incentive regulation made it more difficult to attract capital or resulted in “capital flight.”[141] Concentric also didn’t provide any empirical evidence that incentive regulation is, in any way, riskier for a utility.[142] The witness also couldn’t point to any case where a utility’s credit rating was downgraded as a result of a move towards incentive regulation.

8.21 When pressed further, Concentric admitted that incentive regulation, if done symmetrically, is not riskier for a utility:[143]

> *Well, you’ve read in these reports in the credit rating agencies that about as far as they’ll go is that they’re [incentive rate plans] neutral if they’re symmetric, and they’re fair in the shorter term.*

8.22 Even OPG, in its most recent Business Plan, doesn’t cite incentive regulation as a risk. While many of the risks cited by OPG in its Business Plan align with those cited by the cost of capital experts (both OPG’s and Board Staff’), incentive regulation is not one of them.[144]

8.23 Board Staff’s witness concluded that, while an IRM is “slightly riskier”, it’s far from the biggest factor, which in the case of OPG, “the all important risk here is capital expenditures.”[145]

8.24 It’s also clear that Canadian utilities have lower equity thicknesses than their American counterparts. As highlighted by Board Staff in its final argument, the two Canadian utilities in Concentric’s proxy have the lowest equity ratios – with Fortis at 43.31% equity and Emera at 40.27%. And according to a Concentric report from 2015, the median equity ratio for Canadian electricity distributors was 40%, while it was more than 51% for U.S. distributors. The median equity ratio for Canadian gas distributors was 39.25% in 2015, while it was 50.48% for U.S. gas

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[140] Board Staff argument, page 6-7
[141] Transcript Volume 18, page 4
[142] Transcript Volume 18, page 160
[143] Transcript Volume 18, page 181
[144] Exhibit N1-1-1, Attachment 1, Page 16
[145] Transcript Volume 19, page 89

utilities.[146] Concentric admitted that the difference in equity ratios between Canadian and U.S. utilities wouldn't have changed "materially" using 2016 data.[147]

8.25 The much larger risk facing OPG and its investors, in Energy Probe's view, is that the company has, historically, failed to come anywhere close to earning its allowed rate of return. Between, 2005 and 2015, OPG's actual rate of return was, on average, just 2.18% – well below its Board-approved rate of return. In many years, the rate of return was negative.[148]

8.26 If, for example, OPG earned its allowed ROE of 9.19% on its nuclear rate base in 2020 (the year unit 2 comes into service), that would amount to $337 million, whereas if it earned what it has averaged between 2005-2015, that figure would drop to $80 million, or about $257 million lower.[149] The difference between those two figures far outweighs the difference between having a 45% or 49% equity ratio (a return of $337 million with a 49% equity thickness and $310 million with a 45% equity thickness).

8.27 And finally, OPG's own evidence shows that – given the significant amount of time and money spent on preparing for the DRP – it's statistically more likely than not (90% to be exact) that the DRP will come in under budget. Both cost of capital experts highlighted that, without doubt, the biggest driver of risk for OPG is the DRP, yet the company's own evidence repeatedly suggests that it's a risk the company is confident it can contain. In fact, if the application, as it's currently proposed, goes as planned, there is little risk to OPG from the DRP as the Board will have already approved a P90 budget. If the DRP comes in on budget and on time, then the risks that OPG says require it to have a higher equity thickness will not have come to fruition. If those risks do become a reality – Unit 2 comes in a year late, for example – than OPG's rate base over this test period will still be dominated by the hydroelectric business, as Unit 2 will not have come into service.[150] If that occurs, OPG's argument about nuclear being "riskier" and, as such, its proportion of total rate base be considered when setting an equity thickness, should be ignored.

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[146] K 18.4, page 29
[147] Transcript Volume 18, page 170
[148] Exhibit L, Tab 3.1, Schedule 020 VECC-006
[149] Exhibit L, Tab 3.1, Schedule 2 AMPCO-O16 Attachment 1 Table
[150] Exhibit L Tab 3.1 Schedule 20 VECC-005 Attachment 1 Table 5

8.28 It appears to Energy Probe that OPG is asking to have it both ways. If the Board takes the company's evidence at face value and there's a 90% likelihood that Unit 2 comes in on time and on budget, then there's little risk to OPG. But, if Unit 2 is delayed and those risks that OPG has highlighted become a reality, the company's rate base will likely remain the same over this test period and its nuclear rate base won't overtake its hydroelectric rate base until the next application – meaning the Board should delay any change in equity thickness until 2022.

8.29 Ultimately, Energy Probe sees no reason to raise OPG's equity thickness to 49%.

9. Rate Smoothing and the Mid-Term Review

Issues:

11.5 Is OPG's proposed mid-term review appropriate?
11.6 Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

9.1 Energy Probe is, in principle, opposed to OPG's rate smoothing proposal. That said, we recognize that regulation 53/05 requires the Board to approve some form of rate smoothing. OPG even admitted that, when it comes to rate smoothing, "it was not an option for OPG", as it's simply following regulations put in place by its shareholder.[151] As such, we recommend that the Board approve the smallest possible amount. We provide two examples below.

9.2 Energy Probe's opposition to rate smoothing comes from our belief that the province – which is the sole reason for why rate smoothing is even being considered – is, in essence, picking "winners" when it comes to electricity rates. In doing so, the province is simply shifting the risk of the DRP from current to future ratepayers . If, for example, the DRP ends up coming in 25% over budget, then current ratepayers will have not paid their "fair share" for their portion of the project. If, for example, the final cost of the DRP is double what is currently estimated, today's ratepayers will not only have paid a smaller portion than is fair for their part of the DRP, but will have been allowed to defer the cost of that less-than-fair amount. Given that the Board can't go "back in time" and charge current ratepayers a higher rate, those increases will be tacked onto the bills of future ratepayers who are already paying interest on the deferred

[151] Transcript Volume 22, page 47

amounts that benefited current ratepayers. It's a game of musical chairs, with only future ratepayers left standing. As has been mentioned repeatedly throughout this hearing, the risk that a capital project of the DRP's size (in dollars) and length (10 years) goes over budget or behind schedule is high – based on the track record of the nuclear industry in this province, it's even likely. Kicking that risk to future ratepayers is poor ratemaking, in our opinion.

9.3 OPG's proposal is also at odds with the Board's own policy. As detailed in the RRFE, the Board typically only considers "mitigation", or rate smoothing, when "the total bill increases for any customer class exceed 10%."[152] The Board has reiterated this policy a number of times, notably in the five-year distribution applications for Hydro One and Toronto Hydro.[153] Furthermore, in its last application, OPG explicitly argued against calls for rate smoothing – an argument that the Board ultimately supported in its decision.[154] It's clear to Energy Probe that the Board has an extensive track record of only approving rate smoothing when the total bill impact is greater than 10%. OPG – when not explicitly directed by its shareholder to do so – typically agrees with that policy

9.4 OPG's application, as proposed, simply doesn't cross that threshold. According to Energy Probe's calculations, the average monthly bill impact for a typical residential customer as a result of OPG's nuclear payment amounts is below 1%. OEB Staff's calculations show a similar amount.[155]

9.5 OPG's updated rate smoothing proposal based on Weighted Average Payment Amounts (WAPA) is, in Energy Probe's opinion, more of a PR exercise than anything else. The 2.5% increase that OPG cites, at first glance, seems reasonable, but simply masks the fact that OPG is, in effect, "borrowing" the relatively low increase in its hydroelectric rate and "loaning" it to the nuclear rate. Under OPG's original rate smoothing proposal, it would have raised the nuclear rate by 11% annually, which from a PR point of view sounds dramatic. Yet, under the new proposal, the company (and its shareholder) can publicly talk about a 2.5% rate increase, which sounds far less dramatic, yet masks the fact that under the new proposal OPG is actually deferring less money – and charging ratepayers more up front. The only reason OPG can rely on the far less dramatic 2.5% figure is that under its new proposal it blends the rate of its two

152 RRFE, page 23
153 K22.4, pages 1-5
154 K22.4, pages 6-7
155 Board Staff argument, Schedule A

businesses – its low-risk and low-cost hydroelectric rate with its high-risk and much high(er) nuclear cost. OPG's new rate smoothing proposal further obfuscates a sector that, to many customers, is already overly confusing. Plus, if OPG's effective date proposal is accepted, the company will "back collect" $435 million from ratepayers.[156]

9.6 Furthermore, rate smoothing adds more risk to the company at a time when, according to its own cost of capital expert, it's already facing a significant increase in risk. OPG's evidence on rate smoothing shows that, even under its new proposal – which defers $600 million less than its original rate smoothing plan[157] – that one of its two key "financial viability" metrics will move beyond the company's standard threshold.

Chart 3: Proposed and Alternative Rate Smoothing Scenarios

	Original 11% Proposal[1]	A	B (Proposed)	C	D	E
2017-2021 Average Annual Change in WAPA	**4.3%**	2.0%	**2.5%**	3.0%	3.5%	4.0%
2022-2026 Average Annual Change in WAPA[2]	**6.9%**	8.3%	**7.0%**	5.7%	4.3%	3.0%
2027-2036 Average Annual Change in WAPA[2]	**(1.9)%**	(1.5)%	**(1.0)%**	(0.3)%	0.5%	1.2%
Peak RSDA Balance ($B)	**$3.3**	$3.2	**$2.9**	$3.0	$3.2	$3.4
Total Interest ($B)	**$1.4**	$1.4	**$1.4**	$1.4	$1.4	$1.4
Interest Cost / Deferred Revenue Ratio	**0.5**	0.5	**0.5**	0.5	0.5	0.4
FFO Interest Coverage > = 3 (2017-2021) / (2022-2026)	**3.6 / 5.3**	4.5 / 5.0	**4.6 / 5.4**	4.6 / 5.8	4.7 / 6.2	4.8 / 6.7
DEBT to EBITDA < = 5.5 (2017-2021) / (2022-2026)	**6.2 / 5.3**	5.9 / 5.3	**5.9 / 5.2**	5.8 / 5.0	5.8 / 4.9	5.7 / 4.7
Nuclear Payment Amount Transition Impact ($/MWh)	**($4.3)**	$1.0	**($3.7)**	($9.3)	($16.8)	($22.7)
Average Annual Bill Impact (2017-2021) in %	**0.7%**	0.3%	**0.4%**	0.5%	0.6%	0.7%
Average Annual Bill Impact (2017-2021) in $	**$1.05**	$0.51	**$0.65**	$0.79	$0.93	$1.07
Average Annual Bill Impact (2017-2036) in %[2]	**0.3%**	0.3%	**0.3%**	0.4%	0.4%	0.4%
Average Annual Bill Impact (2017-2036) in $[2]	**$0.43**	$0.43	**$0.47**	$0.53	$0.60	$0.65

9.7 And finally, before we submit an alternative rate smoothing proposal, Energy Probe would like to highlight that since OPG first tabled its application, the province has announced its own rate smoothing plan (the Fair Hydro Plan) that will apply to all residential customers, among

156 Undertaking J23.1
157 Exhibit A1, Tab 3, Schedule 3, Page 10, chart 4

others. While the province has tabled legislation for the Fair Hydro Plan, it has yet to release the detailed regulations on how it will be implemented. Energy Probe believes it's premature to approve a rate-smoothing proposal for OPG when the province has come up with its own plan to ensure monthly hydro bills don't increase at a rate faster than inflation over the next four years. There's only so much rate smoothing that future ratepayers should have to pay for.

Two rate smoothing proposals to consider.

9.8 The first rate-smoothing proposal that Energy Probe supports is detailed in the updated interrogatory response on how to implement rate smoothing without deferring any revenue. The cumulative interest costs of such a proposal are $28 million over the test period, as opposed to the $116 million in cumulative interest costs recorded under OPG's rate smoothing proposal.[158] We should also note that, while OPG's rate smoothing proposal contains $116 million in interest costs over the test period, the interest costs will total $470 million over the entire life of the deferral period.[159]

Table 5
Updated L-1.3-5 CCC-010 Chart 1
Illustration of the Annual Deferred Revenue Requirement and the Associated Interest

Line No.	Description	2017 Amount (a)	2018 Amount (b)	2019 Amount (c)	2020 Amount (d)	2021 Amount (e)
1	Unsmoothed Nuclear Rate[1] ($/MWh)	82.98	82.81	83.87	101.28	96.03
2	Illustrative Nuclear Smoothed Rates, Based on a Constant Rate of Change[2] ($/MWh)	78.07	82.05	90.14	95.67	101.90
3	Forecast Nuclear Production[3] (TWh)	38.1	38.5	39.0	37.4	35.4
4	Annual Deferred Amount ($M)	187	29	(245)	210	(208)
5	Interest Expense ($M)	5	10	5	4	5
5	Cumulative Interest ($M)	5	14	19	23	28

9.9 The second rate proposal comes from Energy Probe's own calculations and is similar to Board Staff's rate smoothing proposal. Under our method, the Board would only approve rate smoothing in 2020, when the nuclear rate jumps as a result of the in-service addition of Unit 2. Under a fully unsmoothed calculation, the change in the *average monthly nuclear cost* to a typical residential customer increases by more than 15%. Under our proposal, we reduce that change to less than 10%. We should note that even if nuclear rates are fully unsmoothed, at no point does the total bill increase move beyond 10%. Under our proposal, the total amount of

158 Exhibit N3 Tab 1 Schedule 1 Attachment 2 Table 5
159 Undertaking J22.2

deferral over the entire test period is $197 million, or about one-third less than Board Staff's proposal.[160]

Year	2016	2017	2018	2019	2020	2021
OPG Regulated Nuclear Rate (Plus Riders) Exhibit N3, T1, S1, Table 3, Line 9 + Line 11	$72.30	$85.83	$85.66	$83.87	$101.28	$96.03
OPG Regulated Nuclear Rate (Plus Riders) in KWh [Line 2/1000]	$0.072	$0.086	$0.086	$0.084	$0.101	$0.096
OPG's Production Forecast						
Total OPG Production, Nuclear and Hydro (TWh) Exhibit N1-1-1 Attachment 1 Page 5	80.8	69.2	70.7	71.2	68.6	66.2
Nuclear Production (TWh) Exhibit N3, T1, S1, Table 2	47.8	38.1	38.5	39	37.4	35.4
Nuclear Production as % of OPG Total Production [Line 6/ Line 5]	59.2%	55.1%	54.5%	54.8%	54.5%	53.5%
Demand for a typical household and ON as a whole						
OPG's Bill Estimate Exhibit N3, T1, S1, Table 1	$150.58	$150.58	$150.58	$150.58	$150.58	$150.58
Typical Consumption (KWh) Exhibit N3, T1, S1, Table 1	789	789	789	789	789	789
Provincial Demand (TWh) Exhibit N3, T1, S1, Table 1	137.6	137.6	137.6	137.6	137.6	137.6
Typical residential demand supplied by OPG (%) [Line5 /Line 11]	58.7%	50.3%	51.4%	51.7%	49.9%	48.1%
Typical residential demand supplied by OPG (KWh) [Line 10*Line 12]	463	397	405	408	393	380
Amount of power the typical household purchases from OPG's nuclear facilities						
OPG Nuclear Production as % of ON Demand [Line 6/Line11]	34.7%	27.7%	28.0%	28.3%	27.2%	25.7%
Typical KWh coming from OPG's Nuclear Production [Line 7 * Line 13]	274	218	221	224	214	203
Cost to Average Household Ratepayer of Nuclear Revenue Requirement						
Cost of OPG Nuclear Production for Typical Household [Line 3*Line 16]	$19.82	$18.75	$18.91	$18.76	$21.72	$19.49
Annual % change in Nuclear Costs for Typical Ratepayer		-5.38%	0.85%	-0.82%	15.80%	-10.25%

[160] Board Staff argument, page 179

Annual change in $ for OPG Nuclear Costs for Typical Ratepayer		-$1.07	$0.16	-$0.15	$2.96	-$2.23
% change to entire bill for Typical Ratepayer (holding everything else constant)		-0.71%	0.11%	-0.10%	1.97%	-1.48%
Example of change in nuclear rate needed to keep increase between -10% and 10%						
Energy Probe Proposed OPG Regulated Nuclear Rate (Plus Riders)	$72.30	$85.83	$85.66	$83.87	**$96.00**	$96.30
OPG Regulated Nuclear Rate (Plus Riders) in KWh	$0.072	$0.086	$0.086	$0.084	$0.096	$0.096
Cost of OPG Nuclear Production for Typical Household	$19.82	$18.75	$18.91	$18.76	$20.59	$19.55
Annual % change		-5.38%	0.85%	-0.82%	9.77%	-5.05%
Annual % change in total bill		-0.71%	0.11%	-0.10%	1.22%	-0.69%
Energy Probe's Annual Cost of Deferral [(Line 2-Line 23 * Line 6)]	0	0	0	0	$197M	0
OPG's proposal deferred amounts		$251M	$162M	-$38M	$488M	$142M
Difference between OPG's and Energy Probe's example		-$251M	-$162M	$38M	-$291M	-$142M

9.10 OPG's updated rate smoothing proposal will also see the company "back collect" $435-million of revenue if the Board releases its decision in September 2017 and approves an effective date of January 2017.[161] Under its previous proposal, that amount would have totalled $341 million, according to Energy Probe's rough calculations (we recognize our numbers are very rough and hope OPG could provide a more detailed number as it did in undertaking J23.1). In essence, mid-way through this proceeding, OPG altered its smoothing proposal in a way that would see the company collect about $100 million more than it originally proposed.

Mid-Term Production Review

9.11 Energy Probe doesn't believe this Board should support a mid-term production review. We very clearly understand that the company is facing a number of risks – most notably with the beginning of the decade-long refurbishment of its Darlington nuclear plant. But we also note that it was OPG's own shareholder that legislated the company to submit (and the Board to approve)

[161] Undertaking J23.1

a five-year application for its nuclear business. Its shareholder could have simultaneously mandated a deferral account to protect the company from such a production risk if it saw fit – as it's done in so many other situations to protect the company from various forms of risk.

9.12 Furthermore, OPG is not proposing any sort of mid-term production review for its hydroelectric business. The reason seems obvious: nuclear power is, inherently riskier. By not having a mid-term production review, OPG has to live with that heightened risk compared to other forms of generation (notably hydroelectric), which we think better reflects the overall risk that nuclear power presents compared to alternative forms of generation.

COSTS

Energy Probe requests that it be awarded 100% of its reasonably incurred costs. Energy Probe worked with other intervenors throughout the process to limit duplication while ensuring that the record was complete.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

May 29, 2017
Brady Yauch
Consultant to Energy Probe Research Foundation
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Consultant to Energy Probe Research Foundation

APPENDIX A

LEI's summary statistics for its trend regression equation are provided in its response to Undertaking J10.2 and are shown here:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.645446573
R Square	0.416601278
Adjusted R Square	0.363565031
Standard Error	0.056587484
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.02515293	0.02515293	7.855029306	0.017192078
Residual	11	0.035223577	0.003202143		
Total	12	0.060376507			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.047100291	0.029659901	1.588012423	0.140590785	-0.018180711	0.112381292
T (time in years)	-0.011755973	0.004194543	-2.80268252	0.017192078	-0.020988101	-0.002523846

APPENDIX B

Energy Probe has conducted a linear regression of LEI's 12 TFP growth rates shown in Figure 27 of its Report against time. The results of this regression are as follows:

SUMMARY OUTPUT	
Regression Statistics	
Multiple R	0.145915
R Square	0.021291
Adjusted R	-0.07658
Standard E	0.087189
Observatic	12

The t-statistic for the -0.0034 estimated time coefficient is -0.466 and is statistically insignificant at the 5% level.

The very low Multiple R (approximately 15%) and R-Square (2%) are particularly strong indicators that there is no relationship between LEI's TFP growth rates and time over its study period. The negative Adjusted R-Square, the scatter plot and trendline confirm that the regression of LEI's growth rates on time provides a very poor fit for the data.

APPENDIX C

February 28, 2017

EB-2016-0152
ENERGY PROBE RESEARCH FOUNDATION
NOTE ON DATA AGGREGATION

Energy Probe Research Foundation ("Energy Probe") has reviewed the expert reports of London Economics International ("LEI")[162] and Pacific Economics Group ("PEG")[163], and their respective responses and revised responses to its interrogatories and those of other intervenors. Energy Probe seeks further clarification on the experts' calculation and reporting of their respective productivity growth rates and intends to question LEI and PEG at the upcoming hearing about, inter alia, the matters raised in this Note.

Energy Probe provides this Note to assist the Board's understanding of how LEI and PEG have obtained their estimates of the long-run productivity growth rate in hydro-electric generation. Energy Probe hopes that this Note will reduce the time devoted to questions on this material at the hearing.

1. Analysis of LEI Growth Rates

At Figure 27 of the LEI Report, LEI presents the percentage changes in its Output and Input Indexes for each year from 2003 to 2014 and the resulting yearly Total-Factor Productivity ("TFP") growth rate which is the difference between the two. Averaging over these twelve yearly changes, LEI reports that the average growth rate of TFP is -1.01% per year.[164]

Using the data as shown in Figure 27, Energy Probe confirms LEI's calculation of the -1.01% average TFP growth rate, but notes that it may be sensitive to the rounding-off of the various data that LEI has used in its calculation and reporting.

The LEI Report does not present the output, input and TFP growth rates for individual companies in LEI's sample. This is perhaps because, as it appears, LEI has adopted an index methodology and has constructed a TFP Index for each company in its sample. Its research problem was therefore to combine these indexes into an industry (or sample) index and compute the annual growth rates of that aggregate TFP index.

Energy Probe sought to understand how the -1.01% average TFP growth rate reported in Figure 27 relates to company-level data. Further to Undertaking JT3.24, OPG provided in hardcopy the annual productivity growth rates that LEI had calculated for each company in its sample of 16 companies for each year in the 12-year period 2003-2014 using its "average growth

[162] EB-2106-0152. Exhibit A1-3-2, Attachment 1. Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry, February 19, 2016. (the "LEI Report")
[163] EB-2016-0152. Exhibit M2. IRM Design for Ontario Power Generation, November 23, 2016. (the "PEG Report")
[164] See LEI Report at p.44.

method".[165] Energy Probe thanks OPG and LEI for their time and effort in responding to its request.

Energy Probe manually entered this hardcopy company-level TFP growth rate data into an Excel spreadsheet, and reviewed and analyzed these data in order to confirm/disconfirm LEI's -1.01% growth rate in Figure 27. To this end, it has conducted various statistical calculations and analyses. In addition to the company growth rates provided by OPG, Table 1 below shows:

- an additional column labelled COMPANY AVG which shows the average of the yearly TFP growth rates for each company, and

- an additional row labelled YEARLY AVG which shows, by year, the average of company TFP growth rates

All of Energy Probe's calculations below used the LEI hardcopy data as received.[166]

It is instructive to examine the data in Table 1. The data can be averaged in three ways: over that entire sample, by company, and by year.

- In the first, there are 12x16=192 observations of the annual TFP growth rate. Energy Probe has calculated the average annual TFP growth rate thereof as approximately -1.01% with rounding. Energy Probe has also calculated the standard deviation of 26.40%.[167]

- In the second, there are 16 rows in Table 1, one for each company in LEI's sample, each row displaying 12 annual TFP growth rates for the years 2003-2014. Averaging over the 12 years for each company, the COMPANY AVG annual growth rates shown in Table 1 range from 3.40% (GPA) to -5.98% (SoCal). The mean of the 16 COMPANY AVG's provides information on the "average company" in LEI's sample; that mean is -1.01% with rounding and the standard deviation is 2.37%.

- In the third approach, Table 1 contains 12 columns of yearly data, each displaying the TFP growth rates of the 16 firms for each year in the period 2003-2014. Averaging over the 16 firms' growth rates in each year, the YEARLY AVG shown in the final row of Table 1 ranges from 20.17% (2009) to -16.98% (2007). The mean over the 12 YEARLY AVG's provides information on the "average year" in LEI's sample period; that mean is -1.01% with rounding and the standard deviation is 10.77%.

165 EB-2016-0152. JT3.24. Chart 1 – TFP Index Growth – Average growth method (%), at p. 2 of 4

166 Energy Probe notes that LEI has formatted and displayed the percentage TFP growth rates to two decimal places in Figure 27 of its Report. In Chart 1 of its response to Undertaking JT3.24, LEI formats and displays the percentage company growth rates to one decimal place and the company averages (AVG) to two decimal points. Since Excel stores numbers to 15 decimal places and calculations in Excel are performed on the numbers as stored, not as formatted, it could be that LEI's calculations are based on its data as stored, not as formatted and reported. Energy Probe worked with the hardcopy data as received. Accordingly, where LEI and Energy Probe have performed the same calculation, there may be differences in the result.

167 Energy Probe used the Excel functions AVERAGE (.) and STDEV.S(.) for these calculations.

Energy Probe concludes that the -1.01% average annual TPF growth rate reported in the LEI Report at Figure 27 (presumably derived from LEI's aggregate TFP index) is confirmed by its own analysis of the company-level data.

Energy Probe invites LEI to confirm/disconfirm Energy Probe's above calculations of the averages and standard deviations from the annual TFP growth rate data provided by OPG in response to Undertaking JT3.24.

TABLE 1

Annual Total Factor Productivity Growth Rates in LEI Sample

Source: LEI Response to Technical Conference Undertaking JT3.24

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	COMPANY AVG
OPG	-3.20%	5.90%	-5.30%	1.10%	-4.20%	11.10%	-1.70%	-16.70%	6.60%	-6.60%	6.10%	0.80%	-0.51%
AB Power	33.60%	-27.00%	0.40%	-37.40%	-82.80%	50.20%	97.00%	-51.40%	-12.00%	-19.20%	72.50%	-40.90%	-1.42%
AP Power	50.70%	-17.70%	-15.20%	-7.00%	-5.20%	-12.10%	19.60%	-6.40%	-3.30%	6.20%	13.80%	-33.30%	-0.83%
Ameren	-8.80%	30.40%	2.70%	-76.70%	46.80%	6.20%	2.60%	8.00%	-6.10%	-26.60%	21.00%	-23.70%	-2.02%
Avista	-14.80%	6.50%	-5.90%	12.40%	-11.30%	3.90%	-3.20%	-6.90%	24.30%	-9.60%	-14.20%	15.10%	-0.31%
Duke	21.50%	-26.70%	8.80%	-12.80%	-6.60%	4.70%	-1.30%	-2.90%	-10.80%	-6.30%	26.50%	-3.10%	-0.75%
GPA	50.70%	-35.70%	8.00%	-35.00%	-18.20%	-36.50%	110.30%	-22.20%	-13.40%	5.80%	65.10%	-38.10%	3.40%
ID	1.70%	-2.90%	2.80%	39.40%	-40.40%	11.00%	16.30%	-10.00%	40.60%	-32.60%	-34.50%	9.40%	0.07%
PacifiCorp	5.50%	-16.10%	-3.50%	36.50%	-21.70%	0.00%	-7.00%	8.30%	21.40%	-4.70%	-32.80%	20.40%	0.53%
PG&E	10.30%	-7.40%	14.50%	17.80%	-61.00%	-0.30%	9.60%	16.10%	13.30%	-50.10%	-2.30%	-25.80%	-5.44%
Portland	-1.30%	3.30%	-9.40%	23.20%	-14.90%	0.10%	-1.10%	6.20%	7.70%	-9.80%	-14.90%	-4.90%	-1.32%
SCE&G	28.90%	-12.20%	12.20%	-26.50%	8.00%	-13.90%	-3.70%	0.80%	-13.40%	6.70%	2.50%	-28.40%	-3.25%
Seattle	-12.90%	-1.10%	-7.50%	19.10%	-4.20%	-4.20%	-6.90%	-2.90%	28.30%	-9.70%	-16.80%	17.10%	-0.14%
SEPA	50.20%	-10.80%	12.20%	-58.70%	-0.90%	-17.20%	28.40%	14.80%	-13.90%	-11.40%	34.60%	-5.70%	1.80%
SoCal	14.20%	-13.20%	37.20%	-2.50%	-70.10%	2.10%	33.50%	11.30%	9.60%	-48.70%	-20.80%	-24.30%	-5.98%
VA	6.60%	-14.30%	-20.60%	9.50%	15.00%	-40.50%	30.30%	19.80%	-12.50%	48.10%	-38.90%	-1.70%	0.07%
YEARLY AVG	14.56%	-8.69%	1.96%	-6.10%	-16.98%	-2.21%	20.17%	-2.13%	4.15%	-10.53%	4.18%	-10.44%	**-1.01%**

2. Analysis of PEG Growth Rates

At page 49 of the PEG Report, PEG states that "over the featured period 1996-2014 sample period, the average annual growth rate in the MFP of all sampled US hydropower generators was about 0.29%." Table 3 of the PEG Report presents the yearly MFP growth rates that PEG has averaged.[168]

It appears that, similar to LEI, PEG adopted an index methodology and constructed an MFP Index for each company in its sample. Its research problem was therefore to combine these indexes into an industry (or sample) MFP Index and compute the annual growth rates of that aggregate index.

Energy Probe submitted interrogatories on the PEG Report on December 2, 2016.[169] In its interrogatory #2 i), Energy Probe requested that PEG provide its calculated productivity growth rate for each company in each year of its sample.[170]

In its response to Energy Probe, PEG referred to several working papers and Excel workbooks that it had provided in response to an interrogatory from Ontario Power Generation which, it noted, contained the information that Energy Probe had requested. PEG did not indicate which working paper or part thereof contained the information that responded to Energy Probe's interrogatory.[171]

From Energy Probe's review of PEG's working papers, it appeared that the information it sought was in Excel workbook M2-11.1-OPG-Attachment PEG-WP-1_20161214.XLSX. That Excel workbook contains a spreadsheet named "Indexes". The Indexes spreadsheet contains the heading "Productivity Calculations". Columns AC, AD and AE thereof contain productivity growth measures by company and by year for "O&M", "CAPITAL" and "MFP" respectively.

On January 8, 2017, Energy Probe requested that PEG clarify certain of its interrogatory responses. In particular, Energy Probe requested that PEG confirm that the Indexes spreadsheet was the document that PEG intended as its response to Energy Probe's Interrogatory #2 i). Energy Probe further requested that PEG confirm that the data in Column AE of that spreadsheet were the data PEG itself used to calculate its 0.29% MFP growth rate, and if not, then to indicate the data source for that number.

On February 8, 2017, PEG filed its revised responses.[172] It did not confirm that the Indexes spreadsheet was the document that PEG intended as its response to Energy Probe's interrogatory. PEG did not indicate the location of the company-level data that it used to calculate its 0.29% average annual MFP growth rate.

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[168] See PEG Report at p.49 and Tables 3 and 4.

[169] EB-2016-0152. Interrogatories of Energy Probe Research Foundation, December 2, 2016

[170] ibid, at p. 4:

> i) As LEI had done, please provide PEG's estimates of annual productivity growth for each company in its sample and for each year in its sample.

[171] EB-2016-0152. OEB Staff IRR, Exhibit M2/Tab 11.1, December 14, 2016. Schedule EP-002 at page 3 states:

> h) The working papers provided in response to M2-11.1-OPG-1 contain year-by-year productivity growth rates for the individual companies in the sample.

[172] EB-2016-0152, OEB Staff M2 11.1 Energy Probe 002 Revised IRR OPG 20170208

a. PEG's Indexes Spreadsheet: Analysis of Column AE growth rates

Energy Probe has downloaded the MFP growth rate information for PEG's "larger sample" of twenty U.S. companies[173] from Column AE of the Indexes spreadsheet for the years 1996-2014 (its "featured sample period"[174]) to an Excel spreadsheet. The information is displayed in Table 2 in a format that facilitates comparisons with the LEI data provided by OPG.

For comparability with Table 1, Table 2 also shows:

- an additional column labelled COMPANY AVERAGE 1996-2014 which shows the average of the yearly MFP growth rates for each company, and
- an additional row labelled Yearly Average which shows, by year, the average of company MFP growth rates

Similar to the LEI data in Table 1, the data in Table 2 for PEG's featured sample period can be averaged in three ways: over that entire period, by company, and by year.[175]

- In the first, there are 20x19=380 observations of the annual productivity growth rate. Energy Probe has calculated the average annual MFP growth rate thereof as 0.088…%. Energy Probe has also calculated the standard deviation of 6.38%.

- In the second, there are 20 rows in Table 2, one for each company in the larger sample, each row displaying 19 annual growth rates for the years 1996-2014. Averaging over the 19 years for each company, the annual growth rates shown in the COMPANY AVERAGE 1996-2014 column range from 3.37% (Virginia Electric and Power) to -3.75% (Puget Sound). The mean thereof provides information on the "average company" in the larger sample; that mean is 0.088…% and the standard deviation is 1.56%.

- In the third approach, Table 2 contains 19 columns of yearly data, each displaying the growth rates of the 20 firms for each year 1996-2014. Averaging over the 20 firms' growth rates in each year, the Yearly Average row shown in the table ranges from 2.46% (1997) to -2.62% (2009). The mean of the 19 Yearly Averages provides information on the "average year" in the featured sample period; that average is 0.088…% and the standard deviation is 1.35%.

As these averages drawn from the data in Table 2 differ from PEG's 0.29% figure, all that can be concluded is that PEG's approach to aggregating company-level MFP data differs from LEI's approach thereto.

173 See PEG Report at p.46
174 ibid.
175 Energy Probe notes that PEG has formatted and displayed the MFP growth rates in Column AE of the Indexes Excel spreadsheet to two decimal places. In Table 2, Energy Probe displays the same data to three decimal places. This is possible because Energy Probe downloaded PEG's Excel data as stored (i.e.to 15 decimal places).

Energy Probe invites PEG to confirm/disconfirm Energy Probe's above calculations of the averages and standard deviations from the annual MFP growth rate data from Column AE of the Indexes spreadsheet.

TABLE 2

				Annual Multi-Factor Productivity Growth Rates in PEG Sample															
				Source Workbook:	M2-11.1-OPG - Attachment PEG-WP-1_20161214.XLSX														
				Spreadsheet:	Indexes														
				Based on Output Capacity															COMPANY
				Logarithmic Annual Growth Rates															AVERAGE
YEAR	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	1996-2014
Alabama Power	0.787%	2.034%	0.330%	1.471%	1.799%	3.481%	0.712%	0.853%	8.300%	1.046%	0.524%	-0.786%	2.353%	4.582%	-3.029%	3.625%	0.436%	4.501%	-3.409%	1.558%
Union Electric	-0.088%	3.158%	-0.493%	1.902%	0.976%	0.535%	0.485%	1.140%	-1.543%	4.435%	0.975%	-2.143%	-2.574%	-2.499%	-6.512%	-5.074%	2.485%	-2.824%	2.465%	-0.273%
Applachian Power	5.959%	-0.076%	1.609%	0.059%	2.355%	-2.640%	4.015%	2.931%	-1.168%	-0.029%	1.791%	-2.569%	7.071%	-9.387%	3.434%	-0.861%	3.534%	-3.364%	-2.853%	0.516%
Avista	-1.719%	2.022%	1.534%	0.617%	-2.935%	6.449%	2.009%	1.355%	0.812%	1.072%	2.599%	3.733%	-0.421%	-9.018%	-1.649%	-3.313%	1.331%	-1.078%	2.697%	0.321%
Duke Energy Progress	-5.687%	5.632%	0.055%	1.234%	0.229%	2.651%	-0.010%	-7.123%	3.097%	1.824%	-0.790%	-1.535%	4.426%	-5.085%	7.778%	0.759%	-1.601%	2.559%	-7.119%	0.068%
Duke Energy Carolinas	3.227%	-1.539%	2.607%	2.125%	-0.101%	4.141%	-0.165%	0.789%	-0.096%	0.735%	3.944%	-0.635%	1.202%	-0.526%	1.169%	0.311%	-5.302%	16.301%	2.134%	1.596%
Georgia Power	-31.228%	8.347%	1.587%	-0.754%	3.661%	-2.747%	5.445%	2.826%	0.338%	0.461%	2.393%	3.397%	-0.638%	6.676%	-4.107%	2.703%	1.754%	1.674%	-4.414%	-0.138%
Green Mountain Power	0.780%	1.491%	0.389%	-2.922%	6.551%	-2.047%	3.016%	-2.047%	3.461%	-0.842%	-4.116%	1.482%	-5.500%	7.568%	-0.528%	13.499%	0.170%	4.058%	2.630%	1.426%
Idaho Power	-3.838%	3.108%	2.783%	-0.053%	2.550%	2.243%	0.989%	1.406%	0.157%	1.422%	0.773%	-0.005%	-1.288%	0.935%	0.457%	1.539%	0.637%	1.423%	1.160%	0.863%
ALLETE (Minnesota Power)	1.400%	8.336%	1.366%	-2.739%	6.157%	0.939%	2.427%	-0.004%	-0.431%	1.826%	-0.466%	2.325%	-3.238%	4.824%	-6.221%	-1.060%	-2.388%	5.384%	-3.884%	0.766%
New York State Electric & Gas	-3.742%	7.567%	3.643%	-8.843%	2.465%	2.065%	2.048%	3.471%	-0.530%	0.453%	4.065%	-3.105%	3.879%	-1.852%	1.061%	0.619%	0.375%	0.149%	2.750%	0.871%
Pacific Gas and Electric	-2.206%	5.820%	1.292%	-1.884%	2.995%	2.713%	0.571%	-0.639%	2.291%	1.189%	3.482%	-3.117%	-0.343%	1.101%	0.151%	-2.362%	-3.461%	-3.089%	-0.312%	0.221%
PacifiCorp	-0.940%	-0.266%	2.079%	2.025%	-0.947%	2.004%	-0.854%	1.321%	-6.125%	1.249%	3.432%	1.782%	-0.540%	-0.265%	-0.999%	-3.147%	-0.969%	-8.258%	1.526%	-0.415%
Portland General Electric	-3.810%	-1.090%	2.172%	-7.218%	3.456%	6.996%	-8.483%	0.099%	2.457%	-0.564%	0.822%	-2.508%	-12.577%	-4.293%	8.608%	-9.447%	-1.435%	-3.457%	14.990%	-0.804%
Public Service Company of Color	-1.449%	3.047%	2.430%	-1.890%	1.410%	-5.949%	2.721%	0.828%	-0.539%	-8.126%	5.857%	-7.442%	6.583%	-14.439%	4.703%	-0.504%	-6.228%	4.748%	-1.065%	-0.806%
Puget Sound Energy	3.147%	-2.253%	1.899%	-0.952%	-2.925%	2.934%	0.828%	0.436%	-21.094%	8.490%	3.890%	-5.651%	-1.246%	-22.190%	1.205%	-1.627%	2.122%	13.232%	-51.532%	-3.752%
Rochester Gas and Electric	5.066%	-2.136%	1.124%	2.604%	1.689%	-0.700%	3.571%	4.087%	-20.736%	0.332%	0.104%	-0.238%	4.834%	-8.367%	-2.940%	-6.772%	4.267%	-50.595%	7.961%	-2.992%
South Carolina Electric & Gas	2.422%	2.467%	1.771%	1.853%	2.280%	0.012%	2.042%	1.326%	0.859%	0.323%	-44.639%	2.033%	0.402%	0.746%	2.816%	2.532%	2.370%	1.948%	1.530%	-0.785%
Southern California Edison	-0.774%	1.145%	4.884%	0.980%	0.490%	-1.229%	0.839%	1.725%	0.318%	1.899%	-2.414%	-1.452%	2.137%	-3.269%	-3.267%	-3.839%	4.171%	-5.174%	5.617%	0.147%
Virginia Electric and Power	3.780%	2.397%	1.455%	1.892%	8.087%	-0.877%	3.518%	2.180%	2.242%	1.246%	1.921%	24.532%	0.495%	2.356%	2.875%	1.380%	3.025%	2.730%	-1.123%	3.374%
Yearly Average	-1.446%	2.460%	1.726%	-0.525%	2.012%	1.049%	1.286%	0.848%	-1.396%	0.922%	-0.793%	0.405%	0.251%	-2.620%	0.250%	-0.552%	0.265%	-0.957%	-1.512%	0.0881%

b. PEG's Aggregation Spreadsheet: Cost-Weighted Growth Rates

Based on Energy Probe's review of PEG's working papers, it appears that PEG has used the information in its "Aggregation" spreadsheet that is contained in Excel workbook M2-11.1-OPG-Attachment PEG-WP-1_20161214.XLSX. Column I contains the MFP growth rates by company and by year for its featured sample of twenty companies over the years 1996-2014.[176] These growth rate data are identical to the data in Column AE of the Indexes spreadsheet referred to above.

Column F of the Aggregation spreadsheet contains PEG's calculated total cost by company and by year, and Column G contains each company's share of the annual aggregate cost of all sample companies in each year.

PEG uses these cost shares as weights for the MFP growth rates it reports in Column I. More precisely, it calculates the average of the current-year cost share and the previous-year cost share and multiplies by the current-year growth rate.

To illustrate using the data as displayed for PEG's company #2's (apparently, Alabama Power), the MFP growth rate in 1996 was calculated as follows:

MFP growth rate: 0.79%
1995 Cost share: 8.12%
1996 Cost share: 6.08%
Weighted MFP growth rate: 0.79% x (8.12% + 6.08%)/2 = 0.056%

Energy Probe has extracted PEG's cost-weighted MFP growth rates for each company and each year of its sample from Column I of the PEG's Aggregation spreadsheet[177] and reported same in Table 3 below. The Table contains 20x19=380 observations of the annual MFP growth rate. Note the weighted MFP growth rate for company #2 in 1996 shown in Table 3 is 0.056%, confirming the calculation immediately above.

As with Table 2, Table 3 also shows an additional column labelled COMPANY AVERAGE in which Energy Probe has calculated the average growth rate for each company over the 1996-2014 period. Table 3 also has an additional row labelled YEARLY AVERAGE in which it has calculated the average of the company growth rates in each year. Once again, the mean COMPANY AVERAGE, the mean YEARLY AVERAGE and the average of all 380 observations are the same and equal 0.014%. The associated standard deviations are 0.085%, 0.086% and 0.374% respectively.

The final row of Table 3 shows Energy Probe's calculation of the year-by-year sums of PEG's calculated growth rates. For example, the sum of all company growth rates for 1996 was found to be -5.034%. These growth-rate YEARLY SUMs in Table 3 are the same as the growth rates reported in Table 3 of the PEG Report.[178]

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[176] In its Indexes spreadsheet, PEG refers to MFP. In its Aggregation spreadsheet, PEG refers to TFP. Energy Probe agrees that the two terms have identical meanings and uses MFP consistently in discussing and analyzing PEG's data.
[177] In extracting the data from the Aggregation spreadsheet, Energy Probe followed PEG's practice and extensively used the advanced Excel data-handling function SUMIFS.
[178] See PEG Report at p. 50, Table 3.

Averaging across the row of YEARLY SUMs, Energy Probe finds that the mean is 0.288% which, upon rounding, becomes 0.29% which, as noted above, is the PEG Report's "average annual growth rate in the MFP of all sampled US hydropower generators"[179]. The standard deviation of the YEARLY SUMs is 1.711%.

Energy Probe invites PEG to confirm/disconfirm Energy Probe's above calculations of the averages and standard deviations from the annual MFP growth rate data in the Aggregation spreadsheet.

3. Interim Comparisons

Subject to confirmation from PEG, Energy Probe believes that its analysis of the PEG data has replicated the procedures that PEG followed in obtaining its 0.29% average annual MFP growth rate as reported in the PEG Report.

More importantly, Energy Probe has shown that LEI and PEG appear to have aggregated their sample data into a final estimate of long-term industry MFP growth in very different ways. LEI has obtained its estimated -1.01% average annual MFP growth rate by *averaging* over its calculated growth rates of each company in each year of its sample. PEG, on the other hand, has obtained its 0.29% estimate by *summing* its calculated weighted annual growth rates of the companies in its sample in each year and then averaging those annual sums.

As suggested immediately above, Energy Probe feels that it may be premature to conclude that LEI and PEG have undertaken very different approaches to deriving their final aggregate estimate from their underlying sample growth rate data. This hesitation springs, in part, from Energy Probe's limited understanding of LEI's sample data. It is not yet clear whether LEI has weighted its sample growth rates in a manner similar to (or different from) PEG's weighting as discussed above. Similarly, the fact that Energy Probe has not identified aggregation by summing in LEI's company-level data does not indicate that LEI has not done so.

[179] See PEG Report at p.49.

TABLE 3

		Weighted MFP Growth Rates by Company and by Year																		Company
pegid	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	**Average**
2	0.056%	0.144%	0.027%	0.118%	0.155%	0.303%	0.057%	0.068%	0.658%	0.081%	0.041%	-0.063%	0.193%	0.389%	-0.254%	0.283%	0.034%	0.343%	-0.253%	0.125%
8	-0.003%	0.092%	-0.016%	0.064%	0.035%	0.019%	0.017%	0.040%	-0.056%	0.159%	0.033%	-0.073%	-0.093%	-0.094%	-0.263%	-0.219%	0.103%	-0.115%	0.100%	-0.014%
9	0.117%	-0.001%	0.036%	0.001%	0.060%	-0.067%	0.091%	0.063%	-0.026%	-0.001%	0.037%	-0.054%	0.137%	-0.167%	0.066%	-0.019%	0.078%	-0.075%	-0.065%	0.011%
12	-0.051%	0.067%	0.056%	0.022%	-0.105%	0.206%	0.065%	0.052%	0.033%	0.043%	0.102%	0.146%	-0.017%	-0.406%	-0.079%	-0.159%	0.063%	-0.051%	0.119%	0.006%
20	-0.044%	0.045%	0.001%	0.012%	0.002%	0.027%	0.000%	-0.074%	0.034%	0.019%	-0.008%	-0.015%	0.045%	-0.054%	0.083%	0.007%	-0.015%	0.023%	-0.064%	0.001%
47	0.362%	-0.170%	0.338%	0.281%	-0.014%	0.566%	-0.021%	0.095%	-0.012%	0.093%	0.474%	-0.074%	0.134%	-0.055%	0.125%	0.034%	-0.586%	1.780%	0.228%	0.188%
64	-4.946%	1.353%	0.094%	-0.044%	0.224%	-0.172%	0.316%	0.155%	0.018%	0.025%	0.130%	0.188%	-0.036%	0.369%	-0.223%	0.145%	0.091%	0.084%	-0.220%	-0.129%
67	0.006%	0.011%	0.003%	-0.024%	0.059%	-0.019%	0.025%	-0.016%	0.030%	-0.007%	-0.035%	0.013%	-0.050%	0.066%	-0.004%	0.118%	0.002%	0.039%	0.024%	0.013%
73	-0.198%	0.164%	0.167%	-0.003%	0.154%	0.124%	0.056%	0.088%	0.010%	0.088%	0.047%	0.000%	-0.074%	0.058%	0.028%	0.087%	0.034%	0.077%	0.064%	0.051%
109	0.013%	0.072%	0.013%	-0.027%	0.063%	0.009%	0.022%	0.000%	-0.004%	0.018%	-0.005%	0.023%	-0.032%	0.047%	-0.060%	-0.011%	-0.024%	0.052%	-0.037%	0.007%
124	-0.038%	0.077%	0.036%	-0.091%	0.032%	0.028%	0.024%	0.035%	-0.005%	0.005%	0.042%	-0.028%	0.030%	-0.014%	0.009%	0.005%	0.003%	0.001%	0.027%	0.009%
142	-0.505%	1.277%	0.307%	-0.454%	0.615%	0.562%	0.144%	-0.162%	0.564%	0.296%	0.885%	-0.782%	-0.084%	0.248%	0.034%	-0.548%	-0.811%	-0.719%	-0.073%	0.042%
143	-0.048%	-0.014%	0.121%	0.112%	-0.057%	0.124%	-0.050%	0.079%	-0.388%	0.080%	0.213%	0.111%	-0.035%	-0.017%	-0.059%	-0.192%	-0.062%	-0.561%	0.107%	-0.028%
148	-0.109%	-0.033%	0.073%	-0.230%	0.118%	0.240%	-0.237%	0.003%	0.067%	-0.015%	0.022%	-0.067%	-0.363%	-0.129%	0.247%	-0.274%	-0.044%	-0.108%	0.476%	-0.019%
153	-0.010%	0.022%	0.020%	-0.015%	0.013%	-0.054%	0.022%	0.007%	-0.005%	-0.068%	0.049%	-0.067%	0.064%	-0.143%	0.048%	-0.005%	-0.064%	0.048%	-0.010%	-0.008%
158	0.065%	-0.045%	0.043%	-0.022%	-0.076%	0.078%	0.019%	0.010%	-0.496%	0.197%	0.089%	-0.128%	-0.032%	-0.654%	0.038%	-0.051%	0.064%	0.412%	-2.059%	-0.134%
159	0.021%	-0.009%	0.006%	0.013%	0.009%	-0.004%	0.017%	0.018%	-0.116%	0.002%	0.001%	-0.001%	0.026%	-0.043%	-0.018%	-0.048%	0.036%	-0.544%	0.094%	-0.029%
167	0.063%	0.060%	0.050%	0.052%	0.068%	0.000%	0.058%	0.037%	0.024%	0.009%	-1.597%	0.087%	0.017%	0.032%	0.121%	0.107%	0.103%	0.083%	0.061%	-0.030%
169	-0.045%	0.072%	0.352%	0.068%	0.034%	-0.088%	0.066%	0.141%	0.024%	0.136%	-0.186%	-0.118%	0.171%	-0.273%	-0.269%	-0.304%	0.328%	-0.400%	0.429%	0.007%
195	0.263%	0.161%	0.111%	0.145%	0.636%	-0.066%	0.247%	0.145%	0.150%	0.083%	0.118%	1.408%	0.029%	0.159%	0.192%	0.082%	0.179%	0.159%	-0.063%	0.218%
Yearly Average	-0.252%	0.167%	0.092%	-0.001%	0.101%	0.091%	0.047%	0.039%	0.025%	0.062%	0.023%	0.025%	0.001%	-0.034%	-0.012%	-0.048%	-0.024%	0.026%	-0.056%	**0.014%**
Yearly Sum	**-5.034%**	**3.345%**	**1.835%**	**-0.023%**	**2.024%**	**1.816%**	**0.940%**	**0.782%**	**0.506%**	**1.241%**	**0.452%**	**0.504%**	**0.029%**	**-0.682%**	**-0.239%**	**-0.959%**	**-0.489%**	**0.530%**	**-1.116%**	
																	Yearly sums average		**0.288%**	

4. Other Issues

Energy Probe intends to raise the following related matters at the upcoming hearing.

a. Logarithmic and Simple Growth Rates

PEG and LEI have constructed productivity indexes for each firm in their samples. These indexes differ in important conceptual ways, but it is also important to understand how the experts have calculated and reported growth rates from their respective indexes.

The PEG Report points out in several places that the growth rates it has reported are logarithmic growth rates.[180] This raises the possibility that PEG and LEI have calculated and reported growth rates in different ways. If LEI's reported growth rate is a simple growth rate, it will only be comparable to PEG's corresponding logarithmic rate where the former is close to zero. However, some reported growth rates in both expert reports exceed 25% so the differences may be substantial.

Accordingly, Energy Probe seeks to determine whether LEI's reported growth rates are logarithmic rates in order to determine their comparability with PEG's reported rates.

b. Variability and Statistical Significance

Energy Probe Interrogatory #1, parts f) and g) asked PEG to perform tests of statistical significance on certain of LEI's and PEG's estimates of annual average MFP growth. PEG concluded that on the basis of these tests, the null hypothesis that the population productivity growth rate differed from zero could not be rejected.[181]

PEG's response to Energy Probe's Interrogatory #1, part f) also includes the statement:

> "However, we note that the small sample can lead to inaccurate results when performing the requested test."

In its expert report, PEG argues for a longer sample period because it "more effectively smooths the effects of volatility in the sample. …".[182] It appears that PEG is asserting a relationship among sample size, variability of sample data, and the accuracy of tests of statistical significance.

Energy Probe wishes to pursue this asserted relationship with the experts and to seek their view on an alternate explanation for the lack of statistical significance: i.e., that there is too much variability in the data, hence increasing the sample size would not necessarily reduce that variability.

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[180] If the one-period growth rate is g, then the logarithmic growth rate is $ln(1+g)$. If g=0.15 (15%), then the logarithmic growth rate is $ln(1.15)$=0.13976… which, after rounding, might be reported as 14%. The logarithmic growth rate is equivalent to the continuously-compounded growth rate.

[181] EB-2016-0152, Exhibit M2, Tab 11.1, Schedule EP-001, p.3. Energy Probe had calculated the 8.40% standard deviation using the data for LEI's TFP Index Growth in Figure 27 of the LEI Report. PEG confirmed Energy Probe's calculation.

[182] See PEG Report at p.60.

Energy Probe also wishes to have the experts' further view on the proper interpretation of a failure to reject the null hypothesis in a conventional statistical test. In particular, does the failure to reject the null hypothesis provide evidence that the true population parameter is in fact zero? Alternately, does the failure to reject simply mean that, on the available evidence, there is no basis for making any conclusion at all about the true value of that parameter?

c. The Research Question

If LEI and PEG have indeed pursued the very different data-aggregation methods discussed above, Energy Probe suggests that they may have interpreted the basic research question differently. It appears that LEI has understood the goal of its research (providing "the industry TFP growth over the study period"[183]) as determining the average productivity performance of the companies in its sample of peer-group hydro generators, i.e. of a typical hydro generator.

It appears that PEG has understood the research question as asking for the aggregate productivity growth of the hydro generation industry over a particular time period. From this perspective, summing the growth rates of the companies in its sample is one way to estimate that aggregate MFP trend.

d. Other Measures of the MFP Growth Rate?

Because of the substantial variability in the annual productivity growth data used by both PEG and LEI, Energy Probe suggests that other growth-rate measures and statistical tests should be considered for determining the appropriate long-run growth MFP rate in North American hydroelectric generation.

One such alternative is the conventional compound annual growth rate ("CAGR"). The CAGR calculation requires only two data points: the value of a company's productivity index at the very beginning of the sample period, and the value of that index at the end of that period. Because the CAGR involves only the endpoints of the sample period, its calculation is unaffected by the intermediate year-to-year variability that contributes to the lack of statistical significance of virtually all of PEG's and LEI's calculated growth rates.

Neither PEG nor LEI report these productivity index levels in their expert reports. An alternate but equivalent CAGR calculation can be made using the annual MFP growth rates from the data already provided.[184]

Using sample data again raises the question of how CAGR's of individual companies should be aggregated into a measure of central tendency. Energy Probe suggests that the *median* CAGR is a better indicator of productivity growth than the arithmetic average thereof. Firstly, it is less affected by extreme values than the average. Secondly, it requires only the endpoints of the sample period and is unaffected by the inherent variability in the data. Thirdly, a negative average productivity growth rate is unacceptable to the policymaker.

Table 4 below shows Energy Probe's CAGR calculations for each company in PEG's larger sample and both the arithmetic average and the median CAGR for the sample. The average is

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[183] See LEI Report, footnote 1 *supra* at p.48.

[184] As PEG and LEI are undoubtedly very familiar with CAGR calculations, it is not necessary to discuss the relevant mathematics in this Note.

-0.154% but the median is 0.147%. On Energy Probe's further tests, neither estimate is statistically significant.[185,186,187]

Energy Probe is interested to have the experts' views on whether the use of the median CAGR or any other particular measure would be an improvement that would assist the Board in determining the appropriate long-term MFP growth rate in this and future cases.

It is apparent to Energy Probe that statistical significance is not, and cannot be, the sole or even the most important criterion for deciding which long-term MFP growth rate the Board should adopt for the purposes of incentive regulation. Indeed, Energy Probe agrees with the Board's policy of rejecting proposed negative growth rates even if the supporting research could demonstrate statistical significance in the conventional manner.

Since, as it appears, neither of the experts' MFP growth estimates are statistically significant, Energy Probe is of the view that the parties and their experts should put forward other criteria that the Board could consider in evaluating the two experts' recommended long-term MFP growth rate.[188]

[185] The sample average is tested on a conventional one-sample two-tailed t-test with a 5% significance criterion.
[186] The sample median is tested with a sign test. Of the 20 CAGR's, 10 are above the median and 10 below. The binomial probability of observing this outcome is approximately 17.6%. With a 5% significance criterion, the null hypothesis is not rejected.
[187] **CORRECTION March 14, 2017:** The test described in footnote 25 incorrect because it tests the wrong null hypothesis. The correct null hypothesis states that the true CAGR is zero. Of the 20 CAGR's, 11 are positive (+) and 9 are negative (-). The binomial probability of observing 11 +'s and 9 -'s in 20 trials is 16.02%. With a 5% significance criterion, the null hypothesis is not rejected.
[188] For example, having regard to its discussion of issues surrounding sample size, Energy Probe suggests that, in this case, larger sample size would not be a good criterion.

TABLE 4

YEAR	Compound Annual Growth Rate
Alabama Power	1.525%
Union Electric	-0.312%
Applachian Power	0.446%
Avista	0.269%
Duke Energy Progress	-0.013%
Duke Energy Carolinas	1.519%
Georgia Power	-0.526%
Green Mountain Power	1.335%
Idaho Power	0.851%
ALLETE (Minnesota Power)	0.702%
New York State Electric & Gas	0.809%
Pacific Gas and Electric	0.190%
PacifiCorp	-0.456%
Portland General Electric	-1.010%
Public Service Company of Color	-0.955%
Puget Sound Energy	-5.092%
Rochester Gas and Electric	-4.162%
South Carolina Electric & Gas	-1.551%
Southern California Edison	0.105%
Virginia Electric and Power	3.251%
Average	-0.154%
Median	0.147%