

ONTARIO ENERGY BOARD

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| FILE NO.: | EB‑2013-0321 |  |
| VOLUME:  DATE:  BEFORE: | 4  June 17, 2014  Marika Hare  Christine Long  Allison Duff | Presiding Member  Member  Member |

EB-2013-0321

THE ONTARIO ENERGY BOARD

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

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

Hearing held at 2300 Yonge Street,

25th Floor, Toronto, Ontario,

on Tuesday, June 17th, 2014,

commencing at 9:32 a.m.

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VOLUME 4

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BEFORE:

MARIKA HARE Presiding Member

CHRISTINE LONG Member

ALLISON DUFF Member

MICHAEL MILLAR Board Counsel

VIOLET BINETTE Board Staff

TED ANTONOPOULOS

RON TOLMIE

CRAWFORD SMITH Ontario Power Generation (OPG)

CHARLES KEIZER

COLIN ANDERSON

CARLTON MATHIAS

ANDREW BARRETT

DAVID CROCKER Association of Major Power

SHELLEY GRICE Consumers of Ontario (AMPCO)

HAMZA MORTAGE

VINCE DeROSE Canadian Manufacturers & Exporters (CME)

JULIE GIRVAN Consumers' Council of Canada (CCC)

DAVID MacINTOSH Energy Probe Research Foundation

LARRY SCHWARTZ

KENT ELSON Environmental Defence

TAM WAGNER Independent Energy System Operator

JESSICA SAVAGE (IESO)

PATRICK DUFFY

DAVID POCH Green Energy Coalition (GEC)

PIPPA FEINSTEIN Lake Ontario Water Keeper

FRED CASS Ontario Power Authority (OPA)

RICHARD STEPHENSON Power Workers' Union (PWU)

BAYU KIDANE

TRAVIS ALLAN Retail Council of Canada

LAURA ZIZZO

JAY SHEPHERD School Energy Coalition (SEC)

MARK RUBENSTEIN

MICHAEL JANIGAN Vulnerable Energy Consumers

JAMES WIGHTMAN Coalition

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Tuesday, June 17, 2014

### --- On commencing at 9:32 a.m.

MS. HARE: Please be seated. We are continuing today with panel number 2, and with staff's cross-examination. So Mr. Millar, please proceed -- oh, I should ask, are there any preliminary matters?

MR. SMITH: The KPMG redlined report as directed has been circulated.

MS. HARE: Thank you. Mr. Millar.

# ONTARIO POWER GENERATION - PANEL 2, resumed

**Bill Wilbur, Previously Affirmed**

**Mario Mazza, Previously Affirmed**

**Robby Sohi, Previously Affirmed**

# Continued Cross-Examination by Mr. Millar:

MR. MILLAR: Thank you, Madam Chair, and good morning, panel. I am going to move now to hydroelectric benchmarking. I have a few questions on that topic. And just to set the table, you might turn to page 6 of Staff's compendium, which is K3.7.

And I understand that OPG does some of its own benchmarking on its -- at least its large-scale hydroelectric assets; is that correct?

MR. MAZZA: Yeah, we hire Navigant and ECG to provide the data for benchmarking.

MR. MILLAR: And if we look at this chart, this is one example, I guess, is the OM&A unit energy cost using EUCG data. What does EUCG stand for?

MR. MAZZA: Well, it refers to a group called Electricity Utility Cost Group, but now they've just attained this acronym, EUCG Incorporated.

MR. MILLAR: Ah, so that's their actual name.

MR. MAZZA: Yeah.

MR. MILLAR: So we don't have to spell it out, I hope.

Okay. So just to confirm, what happens is OPG pays either Navigant, EUCG, or I guess it's the Canada Electricity Association? Is that what CEA stands for?

MR. MAZZA: Canadian Electricity Association.

MR. MILLAR: Yes, so you pay them for the raw data, and then you do the benchmarking analysis yourself; is that correct?

MR. MAZZA: With EUCG and CEA we get the raw data from them. With Navigant they do some analysis themselves as well, and we have, as we mentioned in the evidence, some best-practices workshops with them to review high-level data.

MR. MILLAR: Thank you.

Other than what you have just discussed with Navigant, does OPG do any -- does it have any independently prepared reliability or cost benchmarking studies for hydroelectric?

MR. MAZZA: No, we don't.

MR. MILLAR: And in fact, if you could flip to the next page of the staff compendium, this is an extract from the KPMG report. If you look up from, I guess it's the third paragraph from the bottom there, it states that:

"The reports that were used in the study..."

And this is the KPMG study we found that:

"1), reports did not exist for all business functions, and therefore some business functions such as hydro have not been reviewed in this study."

Do you see that?

MR. MAZZA: Yes, I do see it.

MR. MILLAR: And I understand you did provide them with the data that we just looked at on the previous page, but I guess as you have conceded their view was that's not independent benchmarking; is that fair?

MR. MAZZA: We actually did provide them with data preceding what's in our filing, so it was data based on 2010 and 2009 benchmarking, because the data that we have in our filing wasn't available yet.

MR. MILLAR: Okay. But from KPMG's point of view that is not an independent benchmarking analysis; is that fair?

MR. MAZZA: It's fair if that's what they state.

MR. MILLAR: Okay. And do you intend to do any independent benchmarking of your hydroelectric facilities similar to what you do for nuclear?

MR. MAZZA: We haven't -- we haven't done that, and we don't intend to. This is typically the process that most of the utilities we benchmark with use, so we weren't planning to do any.

MR. MILLAR: Thank you. So the data we looked at from two pages ago related to O&M costs, and I wanted to ask you a little bit about how you prepared that information. I know you got the raw data and then you used it yourself to compile your statistics.

We asked you -- if you can turn to page 9 of the compendium, Staff undertaking JT1.10. And we asked you to provide the EUCG or Navigant definitions of what actually falls into OM&A for benchmarking purposes, and what you provided us with was -- they don't look to be source definitions from EUCG or Navigant, though I could be wrong, but you provided us with an OPG-prepared table.

So first, looking at that table under "cost categories", down the left-hand column, just to take the first one, for example, "facilities operations, direct and support costs associated with unit dispatch and water management", are those your words or are those EUCG and/or Navigant's words?

MR. MAZZA: Those are words that are taken out of the -- I believe it's mostly modelled after the Navigant report, but the individual that works for me tried to make it as common as he could for the two groups.

MR. MILLAR: Okay. So that's OPG's wording, and it's your best attempt to synthesize what both Navigant and EUCG said?

MR. MAZZA: Correct.

MR. MILLAR: Is it possible to get those source definitions? Are they lengthy or difficult to provide?

MR. MAZZA: It is possible to get them.

MR. MILLAR: Can we have an undertaking for that, please.

MR. SMITH: Yes, we will do that.

MR. MILLAR: So that will be J4.1, to provide the source definitions from EUCG and Navigant, related to Board Staff Undertaking JT1.10.

UNDERTAKING NO. J4.1: TO PROVIDE THE SOURCE DEFINITIONS FROM EUCG AND NAVIGANT, RELATED TO BOARD STAFF UNDERTAKING NO. JT1.10.

MR. MILLAR: If I could ask you to flip to the next page and look for example at line 6, "regulatory fees". And if you look over on the comments section, it says -- I guess these are things that both Navigant and EUCG exclude from their analysis, except there is a note that says:

"Navigant's regulatory fees include environmental costs. Navigant's benchmarking cost data is presented with and without regulatory fees. OPG uses the data that excludes regulatory fees, because these costs are outside of management's control and can vary to a large degree."

Do you see that?

MR. MAZZA: Yes.

MR. MILLAR: Not taking any issue with your conclusions there, but is it fair to say that OPG exercises some discretion into what costs they include in their benchmarking analysis?

MR. MAZZA: Every utility exercises discretion. The big fee that we have in our regulatory file is the gross revenue charge. That is the one that we exclude, because it isn't the norm in the North American utility industry. But we do include some costs, safety -- the safety costs and environment costs that are not considered to be unusual fees. In the U.S. the regime is a little bit different. If you look at the regulatory fee description there, they have what they call FERC fees, and these are different than what utilities in the Canadian industry experience. So that is why a decision was made to exclude these fees.

MR. MILLAR: But it's OPG who looks through all the individual cost items within the data that you collect from -- that you buy from these groups, and OPG exercises its judgment as to what should go in; is that fair?

MR. MAZZA: We exercise some judgment, but there is a group that reviews the data and comes to -- there is data review groups for both of these benchmarking studies, and they try to come to a consensus in order to normalize the data, because every utility treats certain costs differently or they put them in different buckets, so there is some discretion, but we think that our benchmarking captures the fees that are relevant as described here.

MR. MILLAR: Sorry, you mentioned a group. What group is that?

MR. MAZZA: Well, Navigant has -- they have -- they meet, I think, two or three times a year, at least the individual that does work with me, to vet the data, review it, and make sure that all the data is consistently treated by each company.

MR. MILLAR: So do they look at the results of your analysis or was that done beforehand? For example, did they review what you included in OM&A?

MR. MAZZA: No, they review the individual data that's provided.

MR. MILLAR: Okay. Thank you very much.

If we can look down at row 9, now, "administration indirect", and if you just look at that cost category, it says:

"Administrative cost related to hydro business, corporate activities, example, hydro central support costs, IT costs, corporate HR and finance."

These look to be generally what OPG would term as corporate cost; is that fair enough?

MR. MAZZA: These are -- no, most of the costs in this bucket -- and again, these are decisions that are made by the groups that benchmark -- they typically include costs up to the, I guess we call it my boss's level, which means the SVP of hydro thermal, so all those costs are included.

Some corporate costs, if they are -- if they are -- if we are able to get them through an allocation process or if they are deemed to be more direct, like IT costs, they do make a decision at the data collection stage on whether to include them or not.

MR. MILLAR: Okay. If we flip back, could you flip back to page 2 of the staff compendium. This is the chart we talked about yesterday.

Line 4 on table 1 is "Corporate costs"?

MR. MAZZA: Yes.

MR. MILLAR: Are those costs included -- those costs would be included in your OM&A analysis for benchmarking; is that right?

MR. MAZZA: No, not -- as mentioned, not all corporate costs are included. A subset of corporate costs are included, as per the, I guess, decisions that are made at the benchmarking study group.

MR. MILLAR: So why would you exclude corporate costs that have been allocated to hydro OM&A?

MR. MAZZA: Because other utilities don't bucket their costs or don't have those costs available. There are a lot of allocations that have to be done, and I guess if you are not required to extract them, it was deemed by some utilities not to provide them.

MR. MILLAR: Well, you are moving, through your business transformation, you are moving a lot of costs. I am not sure if this is so much the case on O&M -- I don't have the numbers in front of me -- but I believe you're at least moving some people from what would have been considered as hydro to corporate, and then you're allocating them back to hydro through corporate cost allocation.

Do I understand that perhaps not all those costs will be reflected in the benchmarking analysis that we looked at on page 6?

MR. MAZZA: Well, in the benchmarking analysis that you have that includes all the costs, there have been no transfers of the staff that are going to be centrally held in the future.

MR. MILLAR: Going forward, what will --

MR. MAZZA: Going forward.

MR. MILLAR: Once business transformation is finished, will those costs still be -- for the purpose of benchmarking, will they be allocated to hydro OM&A?

MR. MAZZA: I can't answer that at the moment, but we will definitely look at it with the benchmarking groups.

MR. MILLAR: Could you turn back to page 10, please? That is where we were. We were discussing administrative indirect.

Does that include what OPG calls centrally held costs?

MR. MAZZA: No, that does not.

MR. MILLAR: Okay. So are centrally held costs excluded from the benchmarking analysis?

MR. MAZZA: Yes, they are.

MR. MILLAR: And why is that?

MR. MAZZA: Well, they are -- as mentioned, there is a methodology that Navigant uses, and these are costs that are bucketed at a higher corporate level, as I've mentioned. So they would be excluded.

MR. MILLAR: But for OPG's own internal allocations, you do allocate those costs directly to hydro; is that fair?

MR. MAZZA: Yes. They are allocated per the model that is described in the evidence.

MR. MILLAR: Can you flip to the next page, please, page 11 of the Staff compendium?

This is a table taken from the evidence; it is the allocation of centrally held costs to previously regulated hydro. And so these are things like pension and OPEB-related costs, insurance, performance incentives, IESO, non-energy charges and other. That's just looking down the line numbers.

These are costs within OPG's control, are they not?

MR. MAZZA: Yes, they are within OPG's control.

MR. MILLAR: And as of 2014/2015, you are at about $26 million for that; is that fair? I am just looking at the total at the bottom.

MR. MAZZA: Yes, that is correct.

MR. MILLAR: I don't know if you need to flip back or not, but your total OM&A for the previously regulated for those two years is about -- between 142 and $145 million. By my math, the centrally held costs are about 18 percent of the total. Would you take that, subject to check?

MR. MAZZA: Yes, subject to check.

MR. MILLAR: Okay. Thank you.

I am going to move on to my next area, a few questions about surplus base load generation, and then I have a couple of questions about the enhanced hydroelectric incentive mechanism. I think some other people may cover this in more detail than I will, so it's not really going to necessarily get to the heart of any of these issues. So forgive me if this comes across as a bit disjointed. I thought I was thought I was going to come after some people on this, but I have some limited cross.

So let's talk first about SBG, or surplus base load generation.

First of all, in the evidence there is no actual forecast for surplus base load generation for 2014 or 2015. Is it possible to provide a forecast of surplus base load generation? Is that something you can provide?

MR. WILBUR: Yes, it is.

MR. MILLAR: And you can provide it for 2014 and 2015?

MR. WILBUR: We can, yes.

MR. MILLAR: Is it possible to segregate it between newly regulated and previously regulated, or is it not broken out that way?

MR. WILBUR: It is broken out.

MR. MILLAR: So you can provide all that?

MR. WILBUR: We can.

MR. MILLAR: Why don't we call that Undertaking J4.2?

UNDERTAKING NO. J4.2: TO PROVIDE FORECAST OF SURPLUS BASE LOAD GENERATION FOR 2014 AND 2015, BROKEN OUT INTO NEWLY REGULATED AND PREVIOUSLY REGULATED.

MR. SMITH: That's fine.

MR. MILLAR: I just have some high-level questions about surplus base load generation and how it works operationally. I think some other people may get into the details more than I do, but I just want to understand what happens.

When there is a surplus base load generation condition, what I understand is that the IESO gives instructions to OPG to curtail production; is that correct?

MR. WILBUR: I would describe it a little bit differently than that. Basically, we, as all other generating participants in the market, we put offers into the market for our generation, and when -- and as -- and so the IESO stacks all those offers up in order of price. And as demand in the market falls, the IESO will start going through those offers and dispatching various units off or reduce -- to reduce. And that's -- and that is what happens as they get to as SBG as well.

MR. MILLAR: So you just get dispatched off?

MR. WILBUR: We get dispatched off or reduced, or down.

MR. MILLAR: But there's a special feature with OPG. Obviously, you are paid -- you are not paid the same way that others are; you are paid for how much you generate, whether or not it is used by the system or not.

So you get paid for the amount that you are dispatched off; is that fair?

MR. WILBUR: Are you referring to the SBG variance account?

MR. MILLAR: Yes, I think I am.

MR. WILBUR: So when we spill because of surplus base load generation -- and that is tracked. We keep track of that, and we have a method to determine what that is described in our evidence.

And we will go to E2.1 –- yeah, there is a high-level description there on page 3 of Exhibit E2.1, where we talk about how we determine what the -- what's going to go into the SBG variance account.

So we start with basically the total volume of spill for all reasons, and then there are various reasons for which we -- not related to SBG that we may have some spill, that are listed here: production capability, water conveyance constraints, market constraints, contractual obligations.

So we remove those volumes of spill from the total, and then we are left with what is potentially SBG spill. And then we apply a price, a price threshold to that. And that, if it's below the -- if the spill occurred at a price that is below the GRC value, then we put that into the variance account.

MR. MILLAR: And again, I apologize if I am just sort of figuring this out as we go along. The reason you dispatch off hydro instead of nuclear is, I guess -- I know you can't tell me anything about prices, so don't answer this if it makes you uncomfortable, but I assume that you have nuclear bid probably -- I am not even going to ask that question.

You figure out how to make sure that you get your hydro dispatched off and not nuclear; is that fair?

MR. WILBUR: That's correct. Our nuclear in general can't follow price.

MR. MILLAR: So when there is a surplus base load generation situation, you will dispatch off water, not nuclear?

MR. WILBUR: That is correct.

MR. MILLAR: And there is a couple of ways you can shed production from your hydro facilities, as I understand it.

One is what you just discussed, which is to spill water; is that right?

MR. WILBUR: Yes.

MR. MILLAR: And that's just to let the water over the dam, or let water go without running it through the turbines and producing electricity; is that right?

MR. WILBUR: That's correct. At most stations, it involves opening spill gates to let the water bypass the generators.

MR. MILLAR: You can record how much water you spill and what that would equate to in megawatt-hours?

MR. WILBUR: We can.

MR. MILLAR: There are some other ways you can avoid generates at a hydro facility as well, right? Many of them, especially some of the newly regulated, has forebays or what I think of reservoirs or behind dams. You can actually let water built up for a while; is that fair?

MR. WILBUR: That's correct.

MR. MILLAR: So you can curtail generation that way as well?

MR. WILBUR: Yes. And that is what we would do first, when we get to -- when we get dispatched down, if we have storage capability, we will make use of it.

MR. MILLAR: Okay. So why don't I just cut right to the chase here?

When you are recording amounts in the SBG -- surplus base load generation -- deferral account, as we discussed, are you recording the amount that you have dispatched off, or just the amount of water that you spill?

MR. WILBUR: As I said, we are starting with, actually, the total volume of spill. So if the water wasn't spilled, it's not even in consideration for that --

MR. MILLAR: Okay. So if you manage to curtail production by storing water instead of spilling water, that would not appear in the surplus base load generation account?

MR. WILBUR: That is correct.

MR. MILLAR: Okay. Thank you. I am going to leave SBG at that, I think.

All right. I am going to have a stab at eHIM, and we will see how this goes. You might want to turn to page 29 of the Staff compendium. I will refer to the Staff interrogatory, which I will refer to in a moment.

I hadn't planned to go through the background, but I think just to introduce the topic quickly I will ask a couple of hopefully very high-level questions about where we were and where OPG hopes to be.

Currently you have what's called a hydroelectric incentive mechanism, or HIM; is that correct?

MR. WILBUR: That's correct.

MR. MILLAR: I guess the way that that works is -- and you can correct me if I am wrong -- in cases where you are able to produce more power than your monthly average hourly production, you can sell that excess production for the market price instead of the payment amount; is that the high-level way it works?

MR. WILBUR: That's correct.

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

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

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

MR. WILBUR: That is correct.

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

MR. WILBUR: Right.

MR. MILLAR: You sort of did some calculations as to how that worked, and I don't think we have to go through that now.

MR. WILBUR: Yes, we have described in evidence, yes.

MR. MILLAR: That's right. And then you get 50 percent of that; is that correct?

MR. WILBUR: That is the way it is currently set up, yes.

MR. MILLAR: Okay. And so you get 50 percent of what, just to be clear?

MR. WILBUR: 50 percent of the incentive revenues.

MR. MILLAR: Okay. So if you sold it for double the payment amount price you would get half of that?

MR. WILBUR: I am not --

MR. MILLAR: Or have I got that wrong?

MR. WILBUR: I am not quite sure. So there is a formula that we would go to evidence, E1.2.1. It's on page 12, 12 of 15 of E1.2.1. Now, this is describing the new -- the enhanced hydroelectric incentive mechanism, but if we look at the box near the bottom of page 12, where it describes the monthly ISO payment is equal to the regulated payment plus the incentive payment, and if we look at the

-- the incentive payment is what we just described. That is where we sell the excess above the monthly average or buy back the shortage below the monthly average.

So if we just ignore the term that says "X factor" there --

MR. MILLAR: Yeah.

MR. WILBUR: -- that's the current in hydroelectric incentive mechanism -- incentive, and that term, we get 50 percent of that.

MR. MILLAR: Okay. I understand, thank you.

Can I direct you to staff 61 of the document I had you pull up before. You discovered there were some unintended consequences to the original hydroelectric -- in fact, the current hydroelectric incentive mechanism, and I think staff summarized it in this interrogatory, so I will read it out. It's about the interaction between surplus base load generation and the incentive mechanism.

What it says, starting at line 11 -- and this is quoted from your evidence:

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

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

MR. WILBUR: It is.

MR. MILLAR: So you were -- I guess this hasn't been foreseen at the time it was all set up, but you were earning more money than you should have been; is that fair?

MR. WILBUR: When there was SBG --

MR. MILLAR: Right.

MR. WILBUR: -- that ended up looking like time-shifting, yes.

MR. MILLAR: And the problem was that this SB -- the surplus base load generation wasn't being -- or it was coming off the monthly average production; is that right?

MR. WILBUR: That's correct.

MR. MILLAR: When in fact it was power you could have produced but didn't because you were constrained on.

MR. WILBUR: Correct.

MR. MILLAR: Okay. And the eHIM is the enhanced hydroelectric incentive mechanism, is OPG's proposal to fix this problem.

MR. WILBUR: Yes, it is.

MR. MILLAR: Okay. Now, other -- I think the ISO in particular but other parties are going to go through the details of that, and in the interests of time I am not going to do that, but I did want to go over a proposal staff had made and your response to that.

So you will see under question A of the interrogatory on page 29, we proposed something that we thought was a simple way to address the problem, but OPG had some concerns about it, so I want to go over that.

The question was, to negate this impact, the impact being the double-counting, I guess:

"Is it not possible to add the amount of SBG generation foregone to the actual production to get an average monthly production compensated for -- compensated for SBG for operating at the HIM?"

I guess what we are saying is, can't you just put the SBG amounts back into the monthly average production numbers? And your response to that was:

"Yes, it's possible to do so. However, doing so would substantially complicate the existing IESO and OPG settlements process, as the IESO does not know the volume or hourly resolution of OPG's SBG spill. By having the IESO perform these calculations, additional financial reporting and settlements process would need to be developed by both OPG and the IESO."

So you see that? That was your response?

MR. WILBUR: Yes, I see that.

MR. MILLAR: First of all, OPG would have the data on actual surplus base load generally -- generation-based water spill? I think we discussed that before. You know how much you spill.

MR. WILBUR: We do.

MR. MILLAR: And you know how much megawatt hours that is.

MR. WILBUR: We do.

MR. MILLAR: So you could do the calculation for an adjusted surplus base load generation monthly average hourly production forecast? That -- on an after-the-fact basis? That wouldn't be difficult to do, would it?

MR. WILBUR: I don't believe that it would.

MR. MILLAR: And since this is all done through deferral and variance accounts anyways, this is all calculated after the fact, I guess where we are struggling, what is the problem? What does the IESO have to know? I guess, why isn't this is a simple solution?

MR. WILBUR: Because I believe what we read into what you are suggesting here is that this would be done by the IESO each month. Right now they pay us the hydroelectric incentive mechanism revenues each month with our normal billing, and I think what you are suggesting is that this would be done at that time as well.

MR. MILLAR: Oh, I see. Well, if we modified that proposal slightly so that OPG does all that actual calculation and it is just fed through the existing deferral and variance accounts, that is something I understand that can be done and solves the problem. And you may have other reasons why eHIM is a better solution. I will let others go over that with you. But is what we propose feasible?

MR. WILBUR: It may be feasible. I wouldn't want to commit our settlements to -- folks to that.

MR. MILLAR: Is it a settlements issue, though? I mean, this all feeds through the deferral and variance account that is settled by the Board. I guess I am not sure what the IESO has to know.

MR. WILBUR: I guess the way you are describing it now I am not sure -- I am not understanding what exactly you are proposing. I thought we understood it when we answered this question, but it seems that you are proposing something different now.

MR. MILLAR: Well, I guess I am proposing that what OPG does is when they make their entries into the SBG deferral and variance account they simply correct for this -- they correct for the SBG spill.

MR. WILBUR: But that is in fact what we are doing. We are proposing -- our proposal, if we go back to E1.2.1, near the end -- actually, back to pages 12 and 13, so actually at the top of page 13, so this is our calculation of the SBG variance account. And this is where we are proposing to correct for the potential double-counting of HIM revenues due to SBG spill.

MR. MILLAR: Let me try one more thing, and then I will finish up. So you could calculate the actual after the fact, adjusted for surplus base load generation hydroelectric incentive mechanism revenues. And I think that is what you are saying you already do? That's in your proposal; is that right?

MR. WILBUR: Correct.

MR. MILLAR: I guess you have some different ideas about the amounts that are shared, and that's the $36 million versus the $18 million that I think some others are going to discuss. I don't have a cross prepared on that.

MR. WILBUR: Yes.

MR. MILLAR: Okay. I am going to leave it at that. Thank you very much, gentlemen. Those are my questions.

MS. HARE: Thank you, Mr. Millar.

I understand, Mr. Duffy, you are next, representing IESO?

## Cross-Examination by Mr. Duffy:

MR. DUFFY: Yes, that's correct. Thank you. Just before I begin, I thought I would highlight for the panel what it is we're going to talk about. As Mr. Millar indicated, our interest here is in the enhanced hydroelectric incentive mechanism or the eHIM. And from the IESO's point of view, it is important because of market efficiency and operability, so we will focus on that topic for our cross-examination today.

Before I begin, just a -- some detail to take care of. We have an exhibit that we are going to enter during the examination. I have distributed that to OPG before. I understand Board Staff have a copy.

MR. MILLAR: Exhibit K4.1. What is that document, Mr. Duffy, just to give it a name?

MR. DUFFY: I think I would call it hourly hydro output and HOEP.

MR. MILLAR: Thank you.

EXHIBIT NO. K4.1: IESO DOCUMENT ENTITLED: "HOURLY HYDRO OUTPUT AND HOEP."

MR. DUFFY: And we have additional copies here if anyone needs one and didn't get one yet.

MS. HARE: Just for the transcript, Mr. Duffy, could you just say what HOEP stands for? Highest Ontario electricity prices?

MR. DUFFY: Yes, the hourly Ontario electricity price. Yes. And I will try not to use acronyms going forward.

MS. HARE: Thank you.

MR. DUFFY: All right. I will begin.

As I mentioned, our questions are going to focus on the hydroelectric incentive mechanism. I believe they will be directed primarily to Mr. Wilbur. I am going to try not to cover areas that Board Staff have already covered.

But just to step back for a second, Mr. Wilbur, can you describe, just set the table for us again, the key elements of the existing hydroelectric mechanism? Put it down into very brief, three, four points, kind of?

MR. WILBUR: Yeah. I think as Mr. Millar pointed out, basically provides us with -- by making us buy back from the market generation when our hourly generation is below the monthly average and allowing us to sell back to the market the excess above the hourly average, both at market prices, that provides us an incentive to operate those facilities to do as much time shifting as we can, to time shift energy from periods of low value to periods of high value. And it simulates the situation where we were getting -- if we were being paid market prices.

MR. DUFFY: And you agree with me that there is ultimately a benefit to the market, and in the end to ratepayers, from time shifting?

MR. WILBUR: There is, as we have described in our evidence. Maybe I will just turn to that, so back to E1.2.1, and page 4 -- or page 6, sorry, page 6 of the E1.2.1, 6 and 7, where we describe the analysis we have gone through to determine the benefit to consumers of time shifting of hydroelectric -- of our hydroelectric resources.

MR. DUFFY: And one of the benefits, I understand, is the shift away from dispatching more expensive generation on peak hours, so the hydro is running, rather than more expensive gas.

MR. WILBUR: Correct. When we produce -- when we increase our hydroelectric output during times of higher value on the system, we are generally displacing gas-fired generation.

MR. DUFFY: So the other benefit that I saw identified in your evidence has to do with export payments, and I am not sure I fully understood that benefit. Can you take us through what that is?

MR. WILBUR: So when we are at times of low value in the market, typically there is no gas-fired generation running, and the demand is being supplied by base load resources, and -- that are contracted and receiving contract prices for their energy, contract or regulated prices for their energy.

And if what we -- when we can reduce our hydroelectric output there, that will have the impact of increasing the market price a little bit. And the exports that are happening at that time will be paying the higher price.

And that increased export revenue goes to offset the global adjustment.

MR. DUFFY: And in your last rate case, OPG was directed to do an assessment of consumer benefits arising from time shifting. Is this the 36 million that's forecast for each of 2014 and 2015?

MR. WILBUR: Yes. That's in table 1 of E1.2.1 on page 7. That's where we have described the consumer benefits and the total reduction in customer cost from the time shifting as -- we have forecasted 36 million in each year.

MR. DUFFY: And then with the 50/50 split mechanism, is it that benefit that gets split? Is it the 36 million that goes 50/50?

MR. WILBUR: Correct. We are proposing to share the benefits to consumers on a 50/50 basis, yes.

MR. DUFFY: And with the enhanced mechanism that you have proposed in this proceeding, the 50/50 was already part of the existing mechanism; correct?

MR. WILBUR: Actually, the 50/50 that we are currently -- from the previous rate case, was just 50 percent of our incentive revenues. So it was not based on an estimate of customer benefit.

Whereas in the enhanced mechanism, we have determined -- we have made a forecast of the customer benefit, and then we are proposing to share that on a 50/50 basis.

MR. DUFFY: Is this the addition of that X factor?

MR. WILBUR: The X factor is the term that allows us

-- or that creates the 50/50 share, yes.

MR. DUFFY: Maybe I am oversimplifying, but you have gone from 50/50 of revenue to 50/50 of benefits; is that accurate?

MR. WILBUR: That's correct.

MR. DUFFY: Okay. And the other key change, as I understand it, to the enhanced hydroelectric incentive mechanism is eliminating the double-counting of the surplus base load generation spill issue that you discussed with Mr. Millar?

MR. WILBUR: That's correct.

MR. DUFFY: And is there any other changes, other than those two, to the formula? Have I missed anything else?

MR. WILBUR: There are no other changes to the formula.

MR. DUFFY: Could I ask you to go to -- you have in front of you E1.2.1, and the tables you were looking at earlier with Mr. Millar at page 12 and 13.

So in the box at the bottom of page 12, you went through this with Mr. Millar and you were looking at the list line there, the "Incentive payment" line.

And to my understanding, is the X factor there -- that's the new addition to this formula?

MR. WILBUR: That is the only addition in that formula, yes.

MR. DUFFY: And then the rest of it there, that's the same as the current?

MR. WILBUR: It is, yes.

MR. DUFFY: And then on the next page, you have got an SBG variance account entry, page 13 at the top?

MR. WILBUR: Yes.

MR. DUFFY: Okay. And then you have the same formula there -- or slightly different, sorry, with the SBG, but you have a similar formula for the incentive payment adjustment at the bottom of that box?

MR. WILBUR: Correct. That is the adjustment for the double-counting due to SBG spill.

MR. DUFFY: Right. So the -- I want to make sure this is clear, because -- so the adjustment for the double-counting happens not under the mechanism as you propose but in the SBG variance account.

MR. WILBUR: That is correct.

MR. DUFFY: I just want to confirm one point. I think you covered this with Mr. Millar, but you agree that the IESO doesn't track OPG's spill volumes?

MR. WILBUR: That is correct.

MR. DUFFY: And so why is it that OPG chose this approach rather than make an adjustment to the hydroelectric incentive mechanism to accommodate the SBG issue?

MR. WILBUR: Again, the reason we chose this approach is that OPG does the calculation for the variance account, and we have all the information required to make this adjustment in this place, so if we had made it in the IESO payment calculation, then we would have -- we -- both IESO and OPG would have needed to change some settlement processes and exchange some additional information.

MR. DUFFY: I am going to turn a little bit here and talk to you about your currently prescribed assets that are at the moment subject to the existing hydro incentive mechanism. I'm right on that?

MR. WILBUR: Yes.

MR. DUFFY: And those would be the Saunders facility, which is a run of river facility? Correct?

MR. WILBUR: Yes.

MR. DUFFY: And DeCew, which is also run of river facility?

MR. WILBUR: Yes.

MR. DUFFY: And the Beck one, which is an intermediate facility.

MR. WILBUR: Correct.

MR. DUFFY: And Beck is the only one, as I read the evidence, that has any form of time-shifting capability of the existing prescribed.

MR. WILBUR: No, actually, as we did describe in our interrogatory response, there is some time-shifting capability at both Saunders and DeCew, a limited capability, but Beck has the vast majority of that capability.

MR. DUFFY: Right. I see. Yeah, no, I wrote down here you wrote that you had minimal four-bay storage at the two run of river facilities, so they have limited peaking.

MR. WILBUR: Correct.

MR. DUFFY: And Beck you have described as a moderate amount of storage, and my understanding is that it can only do storage for a day or something, a short period of time like that?

MR. WILBUR: It is typically used for only a day -- it's typical for one day. It could be stretched over a couple of days.

MR. DUFFY: And I believe you quantified the amount of time-shifting capability at Beck as being 600 to 700 megawatts. Am I right on that?

MR. WILBUR: Yes, so that is in the transcript from the technical conference in response to a question from Mr. Zacher, and I believe that the technical conference transcript actually says 6,700 megawatts, but 6- to 700 -- 600 to 700 was the intent of the response I gave.

MR. DUFFY: Thank you. I wanted to just make sure we clarified that point.

And then turning to the newly prescribed assets, the 48 facilities that have been added, during the technical conference you described that the shifting can take capabilities of all of these assets to be considerably greater than that of Beck? Is that accurate?

MR. WILBUR: Yes.

MR. DUFFY: They also offer, as I understand it, longer-term storage than what would be available at Beck at the moment?

MR. WILBUR: Yes, a number of them are -- will be the determined peaking facilities, which have considerable amount of storage that can at certain times of the year have storage that could be stretched over several days or even weeks.

MR. DUFFY: And I understood that you quantified it as being approximately 2,200 megawatts of the 3,000 or either intermediate or peaking of the newly prescribed facilities?

MR. WILBUR: Yeah, I believe, actually, Mr. Zacher made that -- put that estimate to me, and I said I hadn't actually added it up, but I have since, and on my rough addition which I just did this morning is about 2,100 megawatts.

MR. DUFFY: And so that 2,100 megawatts at present is fully exposed to the hourly Ontario electricity price?

MR. WILBUR: It is.

MR. DUFFY: You agree that's a very strong incentive mechanism for OPG to time-shift for those assets.

MR. WILBUR: It is.

MR. DUFFY: I am going to turn you to the exhibit that we distributed earlier, Exhibit K4.1. And I know this is something prepared by the IESO, so I will just take you through it quickly. This is prepared by the IESO's team based on publicly available output data, and what you will see there is the newly regulated assets in red, the red line, and hourly Ontario electricity price in purple, and then the previously regulated assets in green. And we have done it by season as they go through.

We can just start with figure 1, because I think it's probably the easiest to explain it. So when I look at this -- when I look at it and say, well, it seems to me that it's fair to say that the newly regulated assets under their current structure follow fairly closely with the -- to the general parameters of where HOEP is going?

MR. WILBUR: I would agree with that.

MR. DUFFY: And you would agree with me that --

MR. WILBUR: I would also agree that the currently regulated follow the market price very well as well, just much less ability to time-shift that they currently regulated, so that's the green line on the top. So while it looks flatter, and it is flatter, because there is a significant amount of generation which is run of river and running all the time, it is still going up when price goes up.

MR. DUFFY: But it has limited peaking capability.

MR. WILBUR: Less so than the currently non-regulated, yes.

MR. DUFFY: So it's logical that the newly regulated facilities would more closely follow the market price than the existing ones for that reason?

MR. WILBUR: Yes, but I think it is also a bit of a scale issue there as well, making the currently regulated look flatter than it actually is.

MR. DUFFY: I understand.

MS. HARE: You know what? Since you took a little break, I didn't actually understand what you said, Mr. Wilbur. I am looking at the green line, and to me it does not look like it follows the pattern of the other two lines, and you said it actually it is a scale issue making the currently regulated look flatter than it actually is. Can you just expand on that, please?

MR. WILBUR: Sure. I guess what I would say is if you look at where the highest -- the highest levels of generation are on that green line, they do roughly correspond with those peaks in price. And I guess if you were to remove the base load component of that generation, the run of river component of that generation, and just look at the amount that is actually changing over time, it would more closely match what the non-regulated line looks like.

MS. DUFF: Mr. Duffy, just on this grid that you have provided --

MR. DUFFY: Yes.

MS. DUFF: -- in OPG's evidence there is -- and I'm looking at E1, tab 2, schedule 1, page 12 -- there is a footnote that the IESO does not currently have access to production data for these stations. They are talking about the newly regulated assets. So OPG will work with the IESO and the distributor to develop a settlement solution to enable implementation of this proposal. Am I to understand that the data on this graph is only regarding the data that you have access to today?

MR. DUFFY: Yes. If you look at the red line --

MS. DUFF: Yes.

MR. DUFFY: -- you will see for the newly regulated it is -- it says there in parentheses "directly connected to the IESO grid". It doesn't include those that are embedded.

MS. DUFF: Do you have a rough percentage? How is this representative -- this is you chart --

MR. DUFFY: Right.

MS. DUFF: -- so I just didn't know -- maybe you don't know what you -- the proportion that you don't have access to.

MR. DUFFY: Does Mr. Wilbur know by chance how many --

MR. WILBUR: What I would just refer to is in our Exhibit E1.1.1 there is two appendices at the end, appendix 1 and appendix 2. So appendix 1, newly regulated stations with model production forecasts. And all of those exceptions with one -- all of those stations with one small exception are seen by the IESO, are directly connected to the IESO control grid, so the Kalabogie station, which is the third one down, which is a 4-megawatt station, is the only one that they would not be connected to their grid.

MS. DUFF: Thank you. That's helpful. Sorry for interrupting.

MR. DUFFY: Just on that point, you would agree with me that, now looking at it, all of the numbers for the embedded ones are, comparatively speaking, relatively small quantity?

MR. WILBUR: Yeah. It's about 2 percent of production, are the stations that are not directly connected.

MR. DUFFY: Thank you.

So the remaining figures do the same thing, but each one for a different time period. And you will see that they have some varying reaction.

So figure 2, talking about the fall period, October to December of last year. And, again, I am going to put the proposition to you that the newly regulated assets, they're -- follow the HOEP price, fit the parameter of the HOEP price kind of in a rough fashion?

MR. WILBUR: Yes, but I do believe that the currently regulated are following it as well, to the best of their ability.

MR. DUFFY: So the portion of the currently regulated ones that can are following it?

MR. WILBUR: Yes.

MR. DUFFY: Because we've put in all of the currently regulated ones. As you say, that tends to flatten the line out.

I am not going to take you through the rest of them, but you see they follow for the remainder of the seasons, and then there is one that finishes with a year.

And, Mr. Wilbur, you'll agree with me that the -- if you will, the reward offered by, potential reward offered by following the hourly Ontario electricity price allows OPG to take more risks with time shifting of its facilities?

MR. WILBUR: Yes. I will agree with that.

MR. DUFFY: So you have a greater incentive to do it, but with it comes a greater risk, being exposed to the market price?

MR. WILBUR: Correct.

MR. DUFFY: And you are trying to mimic that incentive when it comes to the existing hydroelectric incentive mechanism, and also with the enhanced mechanism?

MR. WILBUR: We are. We feel that is an excellent -- mimics it very well.

MR. DUFFY: And all of the newly prescribed assets will be covered by your enhanced hydroelectric incentive mechanism?

MR. WILBUR: Actually, just the 21 stations. So in that E1.1.1, appendix 1, stations with modelled production forecasts, those are the ones that will -- that the enhanced hydroelectric incentive mechanism, as well as the surplus base load generation variance account, will apply to.

MR. DUFFY: So most of those are the directly connected facilities?

MR. WILBUR: Yeah. As we discussed earlier, those are the directly connected ones.

MR. DUFFY: And your current hydroelectric incentive mechanism has a 50/50 sharing with ratepayers, as we discussed, and you are going to keep that for the enhanced mechanism as well?

MR. WILBUR: Well, as we discussed, we are proposing to share the benefits that we have forecast on a 50/50 basis with consumers.

MR. DUFFY: And do you know what the -- in practical terms, do you have any sense of what the significance of that change will be, or the difference of how that might work out both for OPG and for ratepayers?

MR. WILBUR: Well, in our forecast, which shows a consumer benefit of 36 million for -- let's just talk about 2014. The current hydroelectric incentive mechanism would generate 51 million in revenues, which, under our current scheme, would -- we would see 50 percent of. So that would be 20, 25 million.

And what we are proposing here is to share the 36 million of consumer benefit equally, which will give us 18 million.

MR. DUFFY: And, Mr. Wilbur, I gather OPG is satisfied that the 50/50 proposal you put forward will be providing a sufficiently strong incentive that these newly prescribed facilities and the existing ones will be responsive to time shifting and the need to move to peak times?

MR. WILBUR: We do. That was discussed at the technical conference, and I responded then that -- when asked directly if we would operate these facilities in the same manner as we do today. And we will.

MR. DUFFY: So you are saying that you have the same level of responsiveness as you do today, being exposed to the hourly electricity price for the newly prescribed ones?

MR. WILBUR: We expect to respond in the same way as we do today, yes.

MR. DUFFY: For the existing facilities that are already subject to the hydroelectric incentive mechanism, the change to the enhanced one, the move to the X factor, do you think that is going to have any sort of impact on your behaviour?

MR. WILBUR: No. As I said -- that is what I was referring to -- under our proposed incentive mechanism here, we intend to operate the facilities in the same way as we do today.

MR. DUFFY: I know from your evidence you also examined a couple of other mechanisms. Can you just quickly highlight what those were and why they were rejected?

MR. WILBUR: Sure. If we look in evidence in E1.2.1, we talked about we did some analysis of alternative incentive mechanisms. It's in section 5.3 starting on page 9.

And we looked at -- we looked at four mechanisms. We looked at the current hydroelectric incentive mechanism, as it is from the last rate case. We looked at our proposal here, which is the enhanced hydroelectric incentive mechanism. We also looked at the mechanism that was in place prior to the hydroelectric incentive mechanism being put in place. That was from 2005 to 2008, the hydroelectric base load forecast mechanism. And then we also looked at an incentive mechanism -- which we just called incentive mechanism, IM -- which is based on a fixed market price exposure.

So we evaluated those different mechanisms.

And the other two, the hydroelectric base load forecast and the incentive mechanism that we have labelled IM, they do not provide the same type of incentive that -- they do not mimic market conditions nearly as well as the current hydroelectric incentive mechanism or our proposed enhanced hydroelectric incentive mechanism.

MR. DUFFY: So you probably agree with me, then, when I suggest to you that if you were to go with one of those other mechanisms, then ultimately there would be less of an incentive for time shifting and then ultimately less of a benefit for ratepayers because of that?

MR. WILBUR: Yes, definitely.

MR. DUFFY: So the 36 million, for instance, in overall benefit that you are forecasting, using the enhanced hydroelectric incentive mechanism, if there was less time shifting, that benefit would not be as significant?

MR. WILBUR: Definitely. If we don't do as much time shifting, that benefit will be reduced, yes.

MR. DUFFY: Just give me a moment, please.

Thank you. That's all of the IESO's questions.

MS. HARE: Thank you.

Mr. Janigan, you are up next?

MR. JANIGAN: I am up next, Madam Chair. I wonder if I can have just five minutes, just to organize it based on the answers from IESO. I was expecting them to be a little bit longer.

MS. HARE: Why don't we then take our morning break now? And we will come back at ten to 11.

### --- Recess taken at 10:32 a.m.

### --- On resuming at 10:57 a.m.

MS. HARE: Please be seated. Okay. Mr. Janigan, are you ready for cross?

## Cross-Examination by Mr. Janigan:

MR. JANIGAN: Thank you very much, Madam Chair.

I am going to go first with examining the problems with the old hydroelectric incentive mechanism, or the one that was in place up to this proceeding. And as I understand it, one of the chief concerns is the perverse incentive that in fact where a spill was not avoided that OPG could still be provided with an incentive during the peak period; is that correct?

MR. WILBUR: I wouldn't call that a perverse incentive, but it did result in -- the hydroelectric incentive mechanism could record revenues for OPG that were due simply to SBG spill.

MR. JANIGAN: So what I want to generally term double-counting. Would you agree with that?

MR. WILBUR: I have used that term myself, yes.

MR. JANIGAN: Okay. Now, in terms of a fix for this problem, did OPG consider a fix that there would be no hydroelectric incentive mechanism incentive in a peak period if there was no time-shifting in the off-peak period preceding it?

MR. WILBUR: No, we did not consider that.

MR. JANIGAN: Would that work?

MR. WILBUR: I don't believe it would. That would not -- as we have discussed, especially with a lot of the newly regulated assets, the time period over which the time-shifting can occur is not just from the previous on-peak period to the next on-peak period, but could be several days and/or weeks.

MR. JANIGAN: So it's the newly regulated assets that present the most problem?

MR. WILBUR: Well, as I also said earlier, the PGS, while it is a smaller storage, it too can be used over more than one day as well.

MR. JANIGAN: Is that a regular occurrence?

MR. WILBUR: It is.

MR. JANIGAN: I wonder if I can turn you to E1, tab 2, schedule 1, page 7, table 2. And I wonder if I am correct in my summary of this table that the net consumer benefit is determined by adding the fuel savings by gas generators not producing on peak due to time-shifted extra OPG production less the increase in the gross revenue charge, GRC, due to more water use on peak, plus increase in export revenues off-peak, because lower off-peak production means higher export prices. Have I effectively summarized that?

MR. WILBUR: Yes, those are the three discrete terms listed in that table, and that 36 million is the sum of those terms.

MR. JANIGAN: And that remains the forecast for consumer benefits for 2014 and 2015?

MR. WILBUR: This forecast is -- in evidence is from our 2013 business plan.

MR. JANIGAN: Now, I wonder, in the -- you might not need to turn this up, but it's in the technical conference transcript on page 51. You confirm that you expect the incremental costs of time-shifting to be about $7 million in both 2014 and 2015. If you want to turn it up, it's on page 51, if your memory --

MR. WILBUR: Yes, that's correct.

MR. JANIGAN: And as you have indicated with my friends, that you are proposing that the enhanced mechanism apply not only to Sir Adam Beck pump generation station, which the currently approved HIM applies to, but extending its application to all the newly regulated hydro facilities with modelled production.

MR. WILBUR: Yes, the ones with modelled production forecast, which is 21 stations.

MR. JANIGAN: These are all run of river facilities, not PGS facilities?

MR. WILBUR: No, these are not run of river facilities, actually. We have, I believe, if we look at Board Staff interrogatory 196 or 7 -- 196, so that's Exhibit L, tab 9.7, Staff 196. So this is where we -- and there is a table, table 1, at the -- starting on page 2 of that interrogatory response, where we list all of the newly regulated stations.

And so in that list, so looking at page 2, the start of table 1, the first 21 of those stations are the ones that we are proposing the enhanced hydroelectric incentive mechanism and the surplus base load generation variance account would apply to, and you will notice the type of station is listed, and so there is a mix of peaking, intermediate, and run of river stations there.

MR. JANIGAN: Thanks very much.

These facilities, however, I take it, have less time-shifting ability compared to plant input than the Sir Adam Beck PGS.

MR. WILBUR: Well, actually, they have considerably more time-shifting ability. So the whole of these -- all of these stations taken together have considerably more time-shifting capability than we have at the Beck.

MR. JANIGAN: I wonder if you could clarify then. In the Undertaking JT1.4 from the technical conference, you provided that the total time-shifting costs for 2012 as being $7 million and for 2013 $6 million.

MR. WILBUR: Yes, we do.

MR. JANIGAN: These were the costs associated with the Sir Adam Beck pump generating station only.

MR. WILBUR: They are, yes.

MR. JANIGAN: Now, given that your forecasted 2014 and 2015 time-shifting costs are 7 million, which includes the costs of Sir Adam Beck pump generation station and the newly regulated hydro facilities, it would appear that the run of river and the non-pump generation hydro facilities, that the time-shifting costs are pretty minimal.

MR. WILBUR: At the PGS the time-shifting costs are easily quantifiable, and they mainly consist of the fact that when we use a specific amount of -- when we pump a specific amount of water into the PGS it takes quite a bit more energy to do that than we will get when we generate that same quantity of water, so there is an efficiency loss.

At the newly regulated facilities there are costs, but they are not as easily quantifiable. I guess an example -- I have two examples which I think I discussed at the technical conference as well. One is, we may operate a facility to get higher output than normal beyond its most efficient operating point, and so there is a cost associated with that.

And also, there are -- there would be additional or lower maintenance costs if we were to operate the hydroelectric on a flatter profile, do less time-shifting. There would be less starts and stops at these units.

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

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

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

MR. WILBUR: That's correct.

MR. JANIGAN: Now, looking at Exhibit 1, tab 2, schedule 1, pages 12 and 13, for your proposed enhanced hydroelectric incentive mechanism, it provides for a regulated payment plus an incentive payment?

MR. WILBUR: You are looking at the formula on page 12; is that --

MR. JANIGAN: Yes, that's correct.

MR. WILBUR: Yes, it does.

MR. JANIGAN: And the regulated payment is just the average hourly production multiplied by the regulated rate, which is then multiplied by the number of hours in the month?

MR. WILBUR: Correct.

MR. JANIGAN: And regarding the incentive payment, is it fair to say that it is an X factor multiplied by the sum of the hourly production differences between actual and average production, weighted by the hourly Ontario electricity price?

MR. WILBUR: That's correct.

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

MR. WILBUR: That's correct.

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

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

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

MR. WILBUR: No, we are not.

MR. JANIGAN: Now, in terms of the different models that you looked at to enhance the mechanism, I wonder if you could turn up IESO Interrogatory No. 4. That's Exhibit L, tab 5.4, schedule 11, page 1.

And I note at the bottom of the page that it says:

"OPG accepted the OEB's decision establishing a 50/50 incentive revenue-sharing mechanism and has not undertaken an analysis of how a different level of or a separate incentive revenue-sharing mechanism would affect its operation of the previously and newly regulated facilities."

Did you understand the previous OEB decision to mandate a 50 percent sharing for any enhanced mechanism?

MR. WILBUR: No, I think we accepted the principle of 50/50 sharing that was in that decision.

MR. JANIGAN: It's not OPG's position that you were fettered by the OEB decision that whatever mechanism you bring forward should be 50/50?

MR. WILBUR: I don't think so, no.

MR. JANIGAN: Okay. Now, Mr. Hammill, if I could turn to your evidence on E1, tab 2, schedule 1, attachment –- oh, Mr. Hammill is not here? Oh. I am sorry. That is the disadvantage of not being here when the panel is empanelled.

Is it OPG's position that the GRC provides an additional customer benefit for customers in this particular mechanism?

MR. WILBUR: I am not sure what you mean by that.

MR. JANIGAN: This is part of Mr. Hammill's evidence, and I am not going to deal with it with you.

Why do you need an incentive to operate the PGS and the additional facilities in order to time shift?

MR. WILBUR: Well, if I can refer to -- we did respond to that question in your interrogatory, which is Exhibit L, tab 5.4, schedule 22, VECC 004.

And I guess I would say that -- so on page 2 in parts (c) and (d) of our response.

First of all, there has always been a financial incentive to operate these facilities, to time shift, even under Ontario Hydro, and when -- from the time these facilities were built. And basically that incentive at that time was if we could time shift to -- would we reduce the overall costs of generating. And Ontario Hydro had all the generation in the province, so if Ontario Hydro could reduce its use of oil-fired generation or coal-fired generation on peak by time shifting water, that was beneficial to Ontario Hydro, that was financially beneficial to Ontario Hydro.

And that -- but now that OPG does not own the entire portfolio of generation, when we time shift in that way now and reduce gas-fired generation, that does not have an impact on OPG's bottom line, as it did for Ontario Hydro in the past.

I would also turn to the notes in the -- or the transcript from the technical conference. And if we could go to page -- it's on page 5 from day 1 of the technical conference.

And this is the IESO was asking some questions, and they basically repeated this this morning, but I will just read from what they said to preface their questions at the technical conference:

"I just sort of preface my questions to say that the IESO is generally supportive of hydro incentive mechanism, in fact thinks that it is essential for both the currently regulated facilities and also for the newly regulated facilities, in order to ensure that they are sufficiently price-responsive and incented to time shift generation from off-peak to on-peak periods, and that this is important for operability and for market efficiency purposes."

And I guess the only other -- I would also add that it's been since regulation has started in 2005 or has returned in 2005, there has been some sort of incentive mechanism for us to follow market prices. And it's consistent with the direction -- I believe the future direction of this Board, going to incentive-based regulation.

MR. JANIGAN: I guess my question is: Why is this different from any other aspect of OPG operations, where, obviously, cost reduction and revenue enhancement is an issue?

MR. WILBUR: Well, as I said, what the IESO and the market operator would like participants to do is to operate the facilities and follow market prices. And this is an incentive that directly incents us to do that, and penalizes us if we don't do it well.

MR. JANIGAN: But what if the incentive was, for example, the ordinary kind of regulatory incentive in the form of a productivity or stretch factor that you had to meet? Wouldn't you be doing the same things?

MR. WILBUR: I am not -- I can't comment on how we would respond to that.

MR. JANIGAN: I guess I am wondering why this is so isolated and so cherry-picked, as it were, for the purpose of providing an incentive where we expect a certain level of efficiency from your entire company.

MR. WILBUR: This isn't the same as incenting efficiencies to reduce costs by having less staff and things like that. This is specifically trying to incent us to behave as if we were operating in an unregulated fashion in this market.

MR. JANIGAN: Are you saying that the benefits outside of the company are such that it's necessary to have this incentive? Is that what you are saying? The benefits go beyond the efficiency of the company. Is that what you are trying to say?

MR. WILBUR: They do. The benefits are for the efficiency of the market, as the IESO stated.

MR. JANIGAN: And they couldn't be achieved except by providing some kind of financial incentive for the company to retain.

MR. WILBUR: We believe this is the best way to achieve that.

MR. JANIGAN: Thank you, Madam Chair. I think those are all my questions for the panel. Thank you, panel, for your patience.

MS. HARE: Thank you.

So next cross-examining will be the School Energy Coalition, and I think we have a tag team, Mr. Rubenstein and Mr. Shepherd. Okay. Thank you.

## Cross-Examination by Mr. Rubenstein:

MR. RUBENSTEIN: Thank you very much. Panel, my name is Mark Rubenstein, and I am counsel for the School Energy Coalition. I will be asking questions with respect to OM&A issues. Mr. Shepherd will be asking questions with respect to the hydro incentive mechanism.

I prepared a compendium -- we have two compendiums, but for the purpose of OM&A we prepared a compendium that was provided to you yesterday. It's titled "panel 2, hydro energy markets panel OM&A". If we can mark that as an exhibit.

MR. MILLAR: Exhibit K4.2.

EXHIBIT NO. K4.2: COMPENDIUM ENTITLED "PANEL 2, HYDRO ENERGY MARKETS PANEL OM&A".

MR. RUBENSTEIN: Now, a lot of the issues that I wanted to address have been discussed yesterday by Board Staff, so I won't go over it, but I want to first discuss your benchmarking and performance metrics and how they are done.

If you can turn to page 6 of the compendium. In the top -- and this is in response to an AMPCO interrogatory asking you to update a number of charts from the evidence, to take into account 2013 actual numbers.

And if we look at the first chart at the top of that page, this is OM&A unit energy cost targets. Do you see that? This is on page 6 of the compendium?

MR. MAZZA: Yes, we do.

MR. RUBENSTEIN: Now, can I just ask you about this chart? Would I be correct that how you set the target for each year is you simply take the OM&A budget for that year and exclude certain items which are included in the footnote there, and then you essentially divide it by the forecasted hydro production? This would be for each plant? Is that generally how you set the target?

MR. MAZZA: Yeah, the target is based on our business plan process, which is essentially what you said. We look at going-forward costs as part of our business planning process, and then the targets are reviewed and set as part of that process.

MR. RUBENSTEIN: Now, with respect to the hydro production aspect of that sort of per megawatt hour, does that include or exclude forecasts for surplus base load generation?

MR. MAZZA: It includes all our -- it includes all the generation that we produce.

MR. RUBENSTEIN: So it includes the forecast --

MR. MAZZA: Yes.

MR. RUBENSTEIN: -- surplus base load generation. Thank you.

Now, I want to ask you some questions about benchmarking, which was discussed yesterday, and I want to understand how OPG with respect to the hydroelectric benchmarking uses it internally, what is the use of that information? And can you tell me at a high level how OPG uses the benchmarking data that it receives?

MR. MAZZA: Well, the way we look at benchmarking is annually we do the benchmarking, as we talked about earlier, where we work with the two different groups in assembling the data, making sure it's consistent, and then from that data we look at the metrics. And the metric we typically use is the OM&A unit and energy cost metric. And since we have 65 facilities we typically benchmark the larger facilities and look at those, and we see how those facilities are changing, and how in aggregate when you look at the whole mix of energy, how they are changing.

So we take a look at that, and if we notice as part of that benchmarking that we are sort of out of whack or there is some deterioration, then we will try and take that into consideration, but we don't use benchmarking necessarily to set the targets, but they are part of the process of looking at the targets for cost.

MR. RUBENSTEIN: So you do not use benchmarking to determine on a sort of go-forward basis what an appropriate OM&A expense should be for a certain plant or plant group or the hydro facilities in total.

MR. MAZZA: We look at the targets, we look at the benchmarking, to see if there is -- that there is some deterioration, as I have said. That is why we have a comparison in the charts over three years, and we look at those numbers and say, what has changed, okay, and at the end of the day when we look at our costs there hasn't been a lot of change in the benchmarking over that period that we looked at. So they are basically in line with what we are proposing as part of our business planning process.

MR. RUBENSTEIN: When you use the term "deterioration", are you using it -- do you use that benchmarking data to ensure that you are improving?

MR. MAZZA: If there are measures -- from an improvement standpoint, what we -- as I referred to before, we have a best-practices session with Navigant. That's an annual process where we look at the data and we discuss amongst the utilities on areas of improvement for the utilities that are benchmarking better, if you will.

So, for example, in the past when we have done this, one area that we looked at was back in the late '90s at operations, where we did look at consolidating our operation -- operating centres and reducing the number of operating centres at that time.

So it's basically used when we can determine from the benchmarking numerical results and discussions with other utilities on what is working for them for -- from an efficiency standpoint, from an effectiveness standpoint, and so on.

So that's the process that we follow with Navigant. The EUCG process is basically a data collection process. We have got the data. Everybody uses the data consistently, and we use their data to also look at, you know, how the facilities rate and how the fleet rates.

MR. RUBENSTEIN: So when I was looking through -- and I didn't produce this in the compendium -- your 2014 to 2016 business plan -- I will just give you the reference -- N1.1.1, attachment 6 -- you don't need to turn it up -- I didn't see any referencing to benchmarking in the business plan; correct?

MR. MAZZA: No, there was no reference. When we -- we used to use it when we were a hydro separate business unit, we used to put some slides in there on benchmarking, but there is no reference in there now.

MR. RUBENSTEIN: Why would you not include that information now?

MR. MAZZA: Well, it is just that at the end of the day the business plan presentation is more of a summary, and initially when we were putting it in our board presentations, the board was interested in how we were benchmarking, and as they looked at the information over time they were satisfied that, you know, our benchmarking results were reasonable and they were in line with other utilities, and we were putting in place where we could best practices, if you will, to drive some efficiencies.

MR. RUBENSTEIN: So would it be fair to say that because it's not in the business plan now it's not as significant?

MR. MAZZA: It is still as significant, but we don't put it as a separate section. I am talking about our business-plan presentation, which you are referring to here in N1; is that correct?

MR. RUBENSTEIN: Yes.

MR. MAZZA: Yes.

MR. RUBENSTEIN: Do you provide the benchmarking in some other form to senior management and/or the board of directors?

MR. MAZZA: Lately we have not provided it to the board of directors. It has not been asked, but my senior manager provides benchmarking to Mitchell as requested.

MR. RUBENSTEIN: And is benchmarking included in any

-- so let me first ask you. There is an incentive paid component to management. And by "management" I mean people with a managerial responsibility in the hydro group; correct?

MR. MAZZA: Yeah, as there is throughout the company, yes.

MR. RUBENSTEIN: And is hydroelectric benchmarking a part of that incentive pay for hydroelectric management?

MR. MAZZA: No, benchmarking is not part of the incentive plan.

MR. RUBENSTEIN: And when we were talking before about the target -- the performance targets -- and this was on page 6 in the materials -- is that included in the incentive paid to hydroelectric management?

MR. MAZZA: The OM&A unit energy cost target?

MR. RUBENSTEIN: Yeah, the sort of --

MR. MAZZA: The targets that are included in incentives for both our corporate scorecard and our hydro scorecard are cost, direct cost, without dividing it by energy, because on an annual basis, as you can see, water availability can drive that number significantly up or down.

So we focus on keeping that quantum of cost down and then we also focus on reliability, because you just can't look at costs; you have to be reliable up to a certain extent for some of these facilities, especially the ones that are in the market. So that is also part of our incentive plan.

So it's a two-pronged approach where we focus on cost and we focus on availability. Those are the two drivers that we put in our scorecard. And we believe that drives the proper incentives to make the units available in the market and so on.

MR. RUBENSTEIN: If I can just take you to page 7, this is the Navigant Consulting hydroelectric benchmarking results. This is the updated numbers.

Now, I don't see any newly regulated facilities here.

MR. MAZZA: The Navigant Consulting benchmarking was done for the -- only for the previously regulated. And the EUCG benchmarking is done for the newly and the previously, so there is nothing here -- nothing here for the previously -- for the newly.

MR. RUBENSTEIN: Why did you not benchmark the newly regulated facilities in the past?

MR. MAZZA: With Navigant?

MR. RUBENSTEIN: Yes.

MR. MAZZA: The main reason is that there is a significant cost to going and benchmarking each facility with Navigant. They were charging -- they had a model where they were charging per station, and we felt that it was pretty significant to benchmark the whole fleet of facilities for benchmarking purposes.

So we did focus on the previously regulated, because they were also being regulated. We used the EUCG benchmarking, which is a lower cost approach, for both the newly and previously regulated.

So we don't rely on one set of benchmarking. We relied on both.

And you can see in the results in our tables there that each benchmarking group benchmarks a little bit different, but in general it gives us a comparator for the previously regulated assets. And going forward, we will likely continue to look at maybe using Navigant selectively for some of the newly regulated plants.

MR. RUBENSTEIN: That would be my next question: Are you planning to, in the future, use Navigant? And I --

MR. MAZZA: We are looking at it with them. As mentioned, their fee structure is such that it would be very expensive to benchmark every station. So we are trying to change our fee structure, to make it more effective for us. And we will look at it with them.

MR. RUBENSTEIN: Between EUCG and Navigant, internally for business reasons, not for presentation to the Board, this Board, which of the two do you -- would you say or do you think is more accurate, is more useful to management?

MR. MAZZA: I would say they both have their benefits. The -- I think we have, if you go back to our -- to the interrogatory that was referred to -- or the undertaking, sorry, undertaking that was referred to this morning, 1.4, I believe -- sorry, JT1.10. Yes, JT1.10.

So you can see from this table that the two benchmarking firms benchmark different sets of costs. The Navigant benchmarking sometimes gets a little bit more granular, and the EUCG benchmark is more appropriate for getting a global view of how you benchmark. So we feel that's more useful when you have that number of facilities.

But they both have their advantages and disadvantages, and they are both good sets of benchmarking. We tend to rely on Navigant more for best practice analysis when we meet every year, and the EUCG benchmarking, we rely more on an overall fleet view, as we are able to extract that data easier and more economically. But they both have their merits.

MR. RUBENSTEIN: If I could just take you back there to page 7, this is the Navigant chart here. There was a discussion -- you could probably keep open, as well, JT1.0, which is also page 9 of the Board Staff compendium.

And I just want to follow up on some questions that you had this morning with Mr. Millar, sort of that general -- about what is included and what is not included in this material.

And if I look -- there was a lot of discussion with Mr. Millar about which corporate costs are allocated or not allocated, but if I also look with respect to the Navigant -- and this is shown both at JT1.0 on the second page and it's in the footnote -- it talks about excluding capital and OM&A investment costs; do you see that?

MR. MAZZA: Yes. In the Navigant data, yes.

MR. RUBENSTEIN: Now, I understood why, for sort of regulatory fees and environmental and regulatory costs, why Navigant did not include them, but why are OM&A investment costs not included?

MR. MAZZA: That is -- Navigant, that's the process and data collection process that Navigant goes through.

A lot of the utilities that benchmark with them, first of all, don't -- aren't able to provide that data on a granular basis like we do.

The other main reason is that they felt that project costs are -- fluctuate a lot year over year, and if you look at it on an annual basis, it's pretty hard to really look at the base -- really, the base cost of operating a business, if you will.

It's easier to benchmark the data that way. That is, I think, their viewpoint.

MR. RUBENSTEIN: And if I could take you -- if you have Board Staff's compendium handy, I'll take you to page 11. There was a discussion with Mr. Millar about the corporate costs that were included and not included. I just want to clarify something.

Because if we look back at page 7 of our compendium, it does say hydro common costs and corporate allocations are included. And I thought I understood your discussion with Mr. Millar, that those costs weren't included?

MR. MAZZA: Well, the bullet here on corporate allocations means the corporate allocations, if you look in the previous interrogatory, that the different utilities are able to consistently extract from their accounting systems.

So, for example, IT costs, where they are direct and utilities treat them consistently, then the benchmarking group deems them to be benchmarked.

However, it doesn't include some corporate costs that the other companies' accounting systems aren't able to extract readily.

MR. RUBENSTEIN: So the chart on page 11 of Staff's interrogatory, this is the allocation of centrally held costs. And my understanding from your discussion with Mr. Millar is those weren't included, or is this part of the discussion we're having right now where some may be included and some may not be included?

MR. MAZZA: The centrally held costs that I believe Mr. Millar was referring to is the pension and OPEB costs, and those are not included. Other companies may not treat the costs the same as we do. They may have it in a different bucket. So those were consistently excluded by everybody. And I think if you look at the results, I think our benchmarking goes back as far as 2011, and these costs weren't as -- may not have been as significant then, but they are not consistently included by the group.

MR. RUBENSTEIN: But if we look at the other centrally held costs on this table, OPG-wide insurance, would that be included in the Navigant information?

MR. MAZZA: Where are you referring to?

MR. RUBENSTEIN: Sorry, I'm looking at page 11 of the Board Staff interrogatory. This is line --

MR. MAZZA: No, OPG-wide insurance is not.

MR. RUBENSTEIN: Performance incentives?

MR. MAZZA: No, they are not.

MR. RUBENSTEIN: And IESO non-energy charges?

MR. MAZZA: No, they are not. And I would like to stress these are not included by the other utilities, so that there is a consistent basis to doing the benchmarking.

MR. RUBENSTEIN: Thank you. I just want to ask you sort of generally about OPG's hydroelectric facilities.

Now, can we agree, compared to the nuclear facilities, that the hydro facilities of OPG are more in a steady state? Would that be a fair characterization?

MR. MAZZA: The nuclear facilities are more of a steady state?

MR. RUBENSTEIN: No, the hydro facilities compared to the nuclear facilities are -- if we can characterize them as more of a steady state.

MR. MAZZA: I think you have to define "steady state". I am not sure what you mean by that.

MR. RUBENSTEIN: Would you agree with me that there -- putting aside the Niagara tunnel, there is no significant investments in the hydroelectric facilities -- well, let me ask you: There are no very dramatic increases in investments that need to be made or are being made to the hydroelectric facilities?

MR. MAZZA: Again, it's a matter of degree on how you are defining, you know, "stable", but when you look at our, I guess, project work program, that is variable. For example, as we have mentioned in the evidence, we have a couple of stations that have an issue with concrete expansion, called alkali aggregate reactivity, so these stations would require, you know, significant investments in the future, which start during the test period.

As the assets age, and when you look at the central hydro fleet, they are over 90 years old on average. They do require investments, you know, to keep them in a reliable or reasonably reliable mode.

So I guess it depends on how you would define, I guess, "stable".

MR. RUBENSTEIN: Would we say the rate -- the year-over-year rate of change of the investments would be -- and I am not just talking about the test year, but sort of farther out from that, and going a little bit in the past, the rate of change would be -- we would expect it to be generally stable. It could be increasing, but that rate of change is increasing -- sorry, would be stable.

MR. MAZZA: I don't think you can make general overriding statements like that.

MR. RUBENSTEIN: If I can take you to page 12.

MS. HARE: Yeah, you know what? Can I just interject? I don't understand your answer at all. I mean, what we heard yesterday was that OPG was prepared to move to incentive regulation on the hydroelectric because the costs are more stable than nuclear, and now you are completely disagreeing with that, so I don't understand how your answer fits with what we heard yesterday.

MR. MAZZA: Okay. Maybe to clarify that, I am talking more on the project portfolio basis that the projects that we do, there is -- there are times when we are going to have to invest more capital as each plant is in the life cycle, and these are lumpier investments.

When we look at it, I guess, in aggregate, I guess if you are talking about total OM&A, if that is your question, is stable, I think it would be more stable that way. I was more focusing on our project portfolio piece when I answered your question.

MR. RUBENSTEIN: But on a total OM&A basis.

MR. MAZZA: Yeah, if you look at the evidence presented yesterday, you will see that over time there are -- although there are some variations, they are fairly stable. I can't speak to the nuclear, whether they're more stable than nuclear, but I would think with the refurbishment that is coming, yes.

MR. RUBENSTEIN: All right. If we can turn to page number 10 of the compendium, and this is your budget versus actual costs. I don't -- we have had a lengthy discussion with Mr. Millar on Friday about the difference between budget and actuals, but I just want to look at the, you know, the Board-approved and budget and planned.

So if we -- looking -- we're looking at sort of -- and we are talking about the previously regulated hydroelectric facilities. We are seeing the 2010 budget of -- this is total OM&A -- of about 114.5. In 2011 -- this was for the last case test year -- 128.2. Then for 2012, 125, and 2013, now we are seeing a very large increase, 120.13 to 141, and then 2014, 145.5, and 2015, 141.1.

I was wondering if you could explain the large increase between 2012 and 2013. And this is not even on your actual spend, but on a sort of a Board-approved spend in 2012 to 2013. But there is a significant increase based on the trend before that.

MR. MAZZA: Well, I can only speak to the hydro portion of that increase, and I would -- probably it would be better to sort of ask the corporate panels on some of the corporate costs on the drivers there.

But for our part of the cost, which is the base OM&A and project OM&A, you were asking why the increase between 2012 and 2013?

MR. RUBENSTEIN: Yes.

MR. MAZZA: And again, there was two main drivers there that I alluded to yesterday, and I could refer you first to the -- we have a labour rate, I guess interrogatory. It's LPMA 009. So we provided that as part of, I believe, a larger interrogatory on the request on labour rates for each of the businesses.

So I think as I explained yesterday, there are some increases related -- at least when it comes to the hydroelectric cost that we can control, there was a significant increase in the labour rate between 2012 to '13 --

MR. RUBENSTEIN: So it's primarily labour rate --

MR. MAZZA: One of them is the labour rate increase, as we alluded to. The other increase, of course, was the

-- if we look at projects, these fluctuate, so some of the increases can be attributed to projects as well.

MR. RUBENSTEIN: But if we are just looking at the base OM&A, so not the project OM&A --

MR. MAZZA: Right.

MR. RUBENSTEIN: -- the primary driver, I just want to understand, is the cost of labour has increased between 2012 and 2013?

MR. MAZZA: Yeah, and as we discussed, there was -- if you are comparing the Board-approved budget, in the Board-approved budget there was a recognition in the budget that we would be filling some of the vacancies in 2013, and although we didn't fill the vacancies, we did replace them with temps and short-term contractors to fill some of the void. So when you are comparing Board-approved to the budget, that was also a driver.

MR. RUBENSTEIN: I just want to clarify, because yesterday there was a discussion with Mr. Millar about the difference -- there was a decrease from the actual versus Board-approved, because instead of filling positions with OPG personnel you used temporary or contract.

MR. MAZZA: Yes.

MR. RUBENSTEIN: And I understood that to mean that those employees were cheaper than -- you know, their labour rates would be less than OPG personnel.

MR. MAZZA: We only -- yeah, in the short-term, just to fill in voids, in the short-term they could be cheaper, but from a long-term standpoint you need to have continuity, especially in the operations area of staff.

So the plan is to fill the vacancies that are required to run the business and operate the business, and we use in the company a short-term strategy, where it makes sense to use temps and contracts.

MR. RUBENSTEIN: But that issue is -- the difference between OPG personnel costs and contract is the reason for the difference between actual versus budgeted. Am I correct? And I am asking about year-over-year budgeted amounts.

MR. MAZZA: Yes, and the year-over-year budget, the main driver, as I indicated, is the -- as I say, if you go into table 1 of that appendix you will see the percentage increase in 2013 being an average of 11.2 percent. So if you go to line 12 there, the weighted average for hydro. So that was a big driver, as I indicated, for that discrepancy.

MR. RUBENSTEIN: If I can take you then, just to flip over to page 11 of the compendium. This is with respect to the newly regulated facility. And if we look at sort of the budgeted year over year and then coming into 2014/2015 forecasts, we see a significant increase between 2012 and 2013. Let me first ask you about that.

Would that be the same issue with respect to the labour rate changes between 2012 and 2013 that you were just discussing with respect to the previously regulated?

MR. MAZZA: Yes. If you look at, as I mentioned, table 1, on lines 10 and 11, both previously and newly regulated had that increase.

MR. RUBENSTEIN: Now, between 2013 budgeted and 2014, there is another significant increase. What would be the drivers for that?

Because we don't see that significant increase with respect to the previously regulated.

MR. MAZZA: Well, you are comparing the actual to the budget?

MR. RUBENSTEIN: No, I'm comparing the 2013 budget to the 2014 plan.

MR. MAZZA: Okay. Yeah, and if you look in that same table, you will notice that our escalation factors have basically normalized to lower levels once that increase was experienced. So really the labour rate increases haven't been as significant.

And the other reason is that the budget numbers are a little bit lower from a staffing point of view, compared to the budget of 2013.

MR. RUBENSTEIN: Now, if we are looking at the same table 11, I see the project OM&A numbers. Now, from 2011, 2012, 2013 -- sorry, the 2011 budgeted and 2012 budgeted, I am seeing, again, an increase compared to 2014 and 2015 now, in terms of project OM&A.

Can you just summarize what the main driver of that is? Is it, again, only labour escalation?

MR. MAZZA: You are talking about project OM&A on table 2?

MR. RUBENSTEIN: Talking about project OM&A.

MR. MAZZA: On table 2?

MR. RUBENSTEIN: Yes. This is line number 2 on page 11 of our compendium.

MR. MAZZA: Yes. So for 2014, with the newly regulated -- and I think if we can go to the interrogatory that we provided, where we tried to explain these changes, it's Staff 69, if you go to that, L-6.1-1, Staff 69 interrogatory.

MR. RUBENSTEIN: I mean, are we talking about the start of major overhauls in the Lower Notch Generating Stations model --

MR. MAZZA: Yeah, it's another -- it's in another Staff interrogatory, I think.

So the answer we provided in the other interrogatory was that there are some big facilities such as Lower Notch, which is one of the facilities that's reached about 40 years old, that we are undertaking a program to bring it back. We also have the Otto Holden facility that I mentioned, that's got the problems with the AR that we are starting the rehab program. And we have got several other facilities that we are undertaking to do some work, so that is why some of the OM&A has gone up for those newly regulated facilities.

MR. RUBENSTEIN: Did you delay doing any maintenance -- sorry, any maintenance or other project -- some things that could be categorized in project OM&A in 2013, knowing that you would be -- there was a discussion on the first panel -- knowing that the regulation would now come into effect and these newly regulated facilities would be regulated? Was there any deferral of work into 2014 or into 2015 because of that?

MR. MAZZA: We were asked the same question by PWU in the interrogatory. And we didn't delay any of this work because of that.

What we do is we evaluate our facilities using portfolio management system. Every year we do a thorough review of the assets and take a look at the state of each asset. Having 69 facilities, that we go through a process during this time of the year. We do a review and we reprioritize where necessary.

And in fact, if you look at that interrogatory, we did even shift some of the value-enhancing work, if you will, to beyond the test period, where it was deemed that it could be deferrable. So we do it based on our plant condition assessments, life-cycle plans and our portfolio management system.

The interrogatory is PWU 002. If you go to --

MR. RUBENSTEIN: You can turn it up if you want, but the takeaway from what you are saying right now is, if I am looking at the variability, none of that was due to knowing at some point that these facilities would be regulated?

MR. MAZZA: No, that is not due to that.

MR. RUBENSTEIN: The last question I have is a follow-up from something that was said yesterday with Mr. Millar. I don't know if the transcript -- if you have a copy of yesterday's transcript or -- and I will just read it to you, and maybe we can put it up. This is page 167 of the transcript, at the top. The discussion you were having with Mr. Millar with respect to filling of vacancies, Mr. Mazza, you said:

"We think we will have the majority of our vacancies as planned filled as part of the process."

This is with respect to this 2014; do you remember that discussion?

MR. MAZZA: Yes, I do.

MR. RUBENSTEIN: I just wanted to clarify what you meant by that. Is this a majority of vacancies over the span of multiple years? Or are you talking you had planned to fill a certain number of vacancies in 2014 and you were going to fill the majority of those in 2014?

MR. MAZZA: Yes. I was referring to 2014 as far as filling vacancies.

MR. RUBENSTEIN: So you have built into the budget, then, to fill all the vacancies? And this is -- and your plan is, where you are right now, you think you are going to fill the majority of those?

MR. MAZZA: Yes. The business plan that you see based on the 2013 was based on filling -- well, basically the vacancies that are in the plan that you see here. And we are planning to fill the majority of the permanent vacancies, but we are, as stated, using, selectively, contract or temps, and in some cases, staff that have come from thermal to do work that is required at the facilities.

So they may not be filling the permanent vacancies, because I think as was stated yesterday, some of the vacancies, there may be a mismatch with availability within the company of staff that are over complement in other areas.

So the plan is to fill the majority of the vacancies. Where we can't fill them due to mismatch, we look at using alternate means. And we plan to accomplish the work program that we set out in the business plan.

MR. RUBENSTEIN: Now, the term "majority of the vacancies" can mean many -- 51 percent is a majority, you know, 90 percent is a majority as well.

Can you just give me roughly a sense of how many of those vacancies you plan to fill?

MR. MAZZA: I can't give you a number, but it's not 51 percent; it's higher than 51 percent. It's -- based on the forecast that we will be providing, the expectation is we will have them, I would say, closer to 90 to 95 percent filled in the plant operation side. And then on the side of -- the engineering side, we likely will have a majority or close to 100 percent end state filed by the end of the year.

And that is part of our business transformation initiative where we have -- where we will have the staff in place to -- for those positions.

MR. RUBENSTEIN: Thank you very much. Those are my half of the questions.

MS. LONG: Mr. Rubenstein, if you can just indulge me for a minute. I just want to go back to something that you talked about just to make sure I'm clear.

Mr. Mazza, on page 10 of SEC's compendium, Mr. Rubenstein took you to line 6, comparing 2012 Board-approved to 2013 budget, and he asked you about the difference between the 125 and the 141, and I think that the answer that he got was that there is an 11 percent difference, and I think that you had said that was due to personnel costs, and I would like to understand that better, because if I look at, I guess, what the average increase might be, that might take us to 3 percent, and as I understood your evidence earlier -- and correct me if I am wrong -- benefits and pensions are not part of this calculation.

So can you explain to me where the other 8 percent comes from in that increase, just so I'm clear, when you talk about personnel costs?

MR. MAZZA: Well, it's --I would -- I would like to defer that to the other panel that explains how the labour rates are determined. There is a process that we go through to the company to determine labour rates.

MS. LONG: And I don't need specific detail, but generally when you said it covers personnel costs, is that for temporary people that you are hiring to do projects? What is encompassed in that?

MR. MAZZA: No, those labour rates apply to our staff with collective agreements. Those are the labour rates, so permanent staff.

MS. LONG: But that wouldn't account for the 11 percent difference.

MR. MAZZA: I am having trouble understanding what you mean, it wouldn't account for...

MS. LONG: Well, if we look at the difference between 2012 Board-approved and 2013 budget, it's about an 11 percent increase, so I am trying to understand what that 11 percent increase consists of.

MR. MAZZA: That consists of taking the labour-rate increase and multiplying it by the number of staff in the business. So that is the incremental amount. So if we have 900 staff in the business, you multiply it by that labour-rate increase, and you get the quantum of the increase, if you will, compared to the previous year --

MS. HARE: Now I am as confused as Ms. Long. I thought the labour increase was in the order of 3 percent, so how -- if you apply the 3 percent, how do you end up with 11 percent increase?

MR. MAZZA: Well, it's in the evidence, as the increase we alluded to, and part of that labour-rate increase was due to the fifty-third year -- sorry, the fifty-third week, I guess, was incorporated in there, and direct pension and OPEB costs, so that is all reflected in the labour rate increase.

MS. LONG: I thought OPEB and pension costs were not included in your OM&A.

MR. MAZZA: Well, the ones that are determinable and part of the labour rates -- and I would defer this to another panel -- there are the centrally held costs.

MS. LONG: Right.

MR. MAZZA: Those are centrally held, so those are not included in our labour rates as we have in that table, but there still are pension and OPEB costs that are included in the direct labour rate that we show in that evidence, in that table, but I think --

MS. HARE: Well, okay. We will look at the transcripts. I think this is different than what we heard yesterday.

MR. MAZZA: Well, I -- my --

MR. SMITH: I have a suggestion. Why don't we provide an undertaking that breaks its out, and we will do it in advance of the compensation panel so that you have the information that is responsive, because you may be missing each other, and you shouldn't be, so we will just provide the undertaking, and then --

MS. HARE: Okay. Thank you.

MS. LONG: Thank you.

MR. MILLAR: J4.3.

UNDERTAKING NO. J4.3: TO PROVIDE CLARIFICATION ON 2012 BA TO 2013 BUDGET ON THE OM&A (LABOUR AND PENSION COMPONENT)

MS. HARE: Mr. Shepherd, it's noon. We could take a break for lunch now, or we could let you go ahead and then take a break, and we are making it your choice.

MR. SHEPHERD: I am not sure I can handle the responsibility.

MS. HARE: I thought so.

MR. SHEPHERD: I have about an hour. I am happy to go part of the way and then have a break, or if you would prefer to have an earlier break, I am happy to do that as well.

MS. HARE: Okay. We have decided we will start.

## Cross-Examination by Mr. Shepherd:

MR. SHEPHERD: Okay. My name is Jay Shepherd. I am co-counsel with Mr. Rubenstein for the School Energy Coalition. And Madam Chair, I have a compendium which is different from my colleague's compendium, bigger, better in all respects, and I think you have copies of it.

MS. HARE: We do.

MR. MILLAR: K4.3.

EXHIBIT NO. K4.3: MR. SHEPHERD'S COMPENDIUM FOR SEC.

MR. SHEPHERD: And I have the joyous task of dealing with surplus base load generation and hydroelectric incentive mechanism. You have covered a number of the things I wanted to cover earlier, which is why I expect maybe an hour instead of an hour and a half.

With Mr. Millar you confirmed that this is really about spilling water; right? And that is to say, you respond to certain types of generation which can't be -- are not dispatchable, like nuclear or wind. You respond to those things being in the market by taking the thing that you can dispatch, which is hydroelectric, and following the load, and when you can't you spill water; right?

MR. WILBUR: Yes, I would just -- I am not sure I would say that not all wind and nuclear is not dispatchable. Some of that is dispatchable, and it is offered into the market, similar to hydroelectric, and if demand falls low enough those things will be dispatched as well.

MR. SHEPHERD: It's true, but nuclear is manoeuvrable, and it takes, like, 24 hours, right, so you can't really respond to peak level.

MR. WILBUR: OPG's nuclear, yes.

MR. SHEPHERD: Okay. And so -- but the result is that because of the mix of generation it ends up being the hydroelectric component where the potential energy is wasted, because that's where you have the opportunity to adjust; right?

MR. WILBUR: Yes.

MR. SHEPHERD: Okay. And I want to take you to, in our materials, page 2 of our materials, which is one of your interrogatory responses, SEC number 70, under issue 5.4, and this talks about how you calculate the spill. And I don't want to go through it in detail, but I do have a couple of questions about it.

You first have to measure how much water have you wasted. Instead of putting it through a turbine, you put it over the dam or through a spillway or something like that; right?

MR. WILBUR: Yes.

MR. SHEPHERD: Okay. And so under item 1 here you talk about how you get the information for that for Beck, how much spill you had at Beck. That's really not your calculation; right? It's something that is provided to you by the International Niagara Border Patrol?

MR. WILBUR: The Niagara River Control Centre, actually.

MR. SHEPHERD: Yeah, okay. And -- but for the other facilities you actually calculate how much water did you put through the -- you open spill gates, right, and you calculate how much water did we put through it?

MR. WILBUR: Correct, based on the elevation in the forebay, when you open the spill gate a certain amount, you know how much water is flowing through.

MR. SHEPHERD: It's just math. You don't have a flow metre. You just -- it just --

MR. WILBUR: That's correct. There is no metre. It's just math.

MR. SHEPHERD: All right. And you do this all station by station on an hourly basis?

MR. WILBUR: We do.

MR. SHEPHERD: But from the point of view of surplus base load generation calculations for this Board's purposes, the total is the total. It doesn't matter where you spilled it. The total is the total.

MR. WILBUR: Well, actually, in determining the amount of SBG spill that will count in the variance count, we do need to know which station it's at, because the different stations have different costs, different GRC costs, and whether SBG spill counts in the variance account or not is dependent on what the price is relative to that GRC cost.

MR. SHEPHERD: All right. So --

MS. HARE: Can I just remind you again not to use acronyms, please? So you are talking about gross revenue charge?

MR. WILBUR: Sorry, gross revenue charge, yes.

MR. SHEPHERD: So you take the total spill, and then you deduct the types of spill that are not because of other base load generation, they are for other reasons, because sometimes you have to waste water, right? For example, at Beck you can't use all the water in the generating station. Some of it has to go over Niagara Falls.

MR. WILBUR: That's correct.

MR. SHEPHERD: Okay. So there is a series of calculations that you do to reduce the amount that you didn't put through the turbines to an amount that is actually surplus-base-load-generation-driven; right?

MR. WILBUR: Yes, we do that, that subtraction, to get to what we call potential surplus base load generation spill, and then we apply the price test to it.

MR. SHEPHERD: Before we get there, though, in each of these cases you doing an estimate. It's still on a per-station basis, right?

MR. WILBUR: It is on per-station basis.

MR. SHEPHERD: You are doing an estimate that is basically engineering judgment on your part, right?

MR. WILBUR: In some cases it would be. I guess some simple examples that I can give are, for instance, there are times when the inflow into the plant is greater than the capacity of the plant, so we are going to have to open spill gates and spill that water past.

MR. SHEPHERD: You have a spring run-off and you just have too much water to use?

MR. WILBUR: It happens at most of our stations every spring. In addition also, there are times when there are outages to units, so our capacity is reduced. And again, that may result in spill.

MR. SHEPHERD: And so you do these calculations on a station-by-station and hour-by-hour basis to get to your potential SBG spill -- sorry, surplus base load generation spill, and who checks those calculations? I mean, you do them internally, I understand, but who verifies that you have done this right? Anybody?

MR. WILBUR: The operators at the station determine these amounts, and they are submitted to a central database.

MR. SHEPHERD: At OPG?

MR. WILBUR: At OPG.

MR. SHEPHERD: But there is nobody -- like, for example, IESO doesn't review your calculations to make sure you have done them correctly?

MR. WILBUR: They do not, and I don't believe they would have the capability to verify those numbers.

MR. SHEPHERD: So we are sort of relying on your number, right?

MR. WILBUR: You are.

MR. SHEPHERD: And then you take the final number and you say: All right, if we spilled water and we could have received more from the market than the gross revenue charge, we shouldn't have spilled it, and therefore we can't count it as surplus base load generation, right?

MR. WILBUR: You are referring to the price test now?

MR. SHEPHERD: Yes.

MR. WILBUR: Yes. We are basically saying if the price in the market was below the cost, the gross revenue charge cost for that facility, then it is appropriate to count that as surplus base load generation, the spill.

MR. SHEPHERD: And if the price in the market was above that, then you shouldn't have spilled? Because you have adjusted for all the other reasons why you have spilled.

MR. WILBUR: That is correct.

MR. SHEPHERD: Okay. You -- we haven't heard, I don't think, on the record your forecast of surplus base load generation for 2014 and 2015, but I think it is actually calculable from the record, and tell me whether this is right.

If you go to page 6 of our materials, this is an update that you have provided to AMPCO Interrogatory No. 23, and this was filed on June 3rd. And in -- on page 6 of our materials, you see under number (c) you say that:

"The hydroelectric production totals in the application are production before adjusting for surplus base load generation."

But the production totals in your business plan, which you also filed at this time -- which you filed, have the deductions for surplus base load generation.

So the difference between the two is going to be your surplus base load generation, right?

MR. WILBUR: Yes, that is correct.

MR. SHEPHERD: Okay. And will you accept, subject to check, that that difference is, for the previously regulated, it is 0.6 terawatt-hours in each of the two years?

And the information is here on pages 8 and 9, if you want to check, but it appears to be 0.6 in each of the two years for previously regulated and 0.3 in 2014 and 0.6 in 2015 for the newly regulated; does that sound about right?

MR. WILBUR: That sounds about right. I will accept that, subject to check.

MR. SHEPHERD: And the total is 2.1 terawatt-hours?

MR. WILBUR: Over the test period for both, yes.

MR. SHEPHERD: If you then -- the way you get compensated for surplus base load generation is you get -- the gross amount you get is the payment amount as if you generated that generation, but then you have to deduct from it the gross revenue charge, right?

MR. WILBUR: That is correct.

MR. SHEPHERD: So the gross amount of that 2.1 terawatt-hours, will you accept, subject to check, that it is $94.1 million?

MR. WILBUR: Sounds close.

MR. SHEPHERD: Okay. And then what's the gross revenue charge? What's the per terawatt-hour gross revenue charge? That would be about 15 million for that -- for that 2.1 terawatt hours? 14 million?

MR. WILBUR: Well, it depends, as a -- if it was -- I mean, the gross revenue charge is different for different plants.

MR. SHEPHERD: Okay?

MR. WILBUR: So the largest plants, it's around close to $15, but it does vary as low as $5, depending on the --

MR. SHEPHERD: I thought your average was $7 for these facilities, your weighted average; is that not right?

MR. WILBUR: I don't know what the weighted average would be.

MR. SHEPHERD: Anyway, you are anticipating that over the course of 2014 and 2015, you are going to get a net amount from the ratepayers of somewhere in the order of 80 million as compensation for surplus base load generation; is that -- am I in the ballpark?

MR. WILBUR: I would have to check that. I am not -- that sounds reasonable based on what we have discussed here, but I prefer to check that.

MR. SHEPHERD: All right. I will leave it with you that if it turns out that that is wrong, you will advise the Board so that we have a more correct calculation. Okay?

Now, the existing hydroelectric incentive mechanism -- I am going to come back to surplus base load generation in a second, but the existing hydroelectric incentive mechanism, you have discussed how this works with Mr. Duffy and Mr. Millar.

And as I understand it, basically, it's how much more is the production you do above average worth compared to the production you produce below your average. So if you are efficiently volatile in your production, if you follow load, you will produce more value, and therefore that is the calculation of your hydroelectric incentive mechanism, your current one, right?

MR. WILBUR: That's correct. I would just say follow price instead of follow load, but yes.

MR. SHEPHERD: It's interesting you say that, because price generally follows load, right?

MR. WILBUR: It does, generally, but as time goes on here, we are having more and more variable generation, solar generation and wind generation, that may change that picture.

MR. SHEPHERD: And that's only because of market inefficiencies. That's not -- the price should actually exactly follow load, right?

But it doesn't, because sometimes there is market inefficiencies because of the bidding system?

MR. WILBUR: I am not sure that market inefficiencies is the right way to describe it. It just -- those are effectively base load sources of energy, and they are variable and less predictable than the current -- our standard definition of base load generation.

MR. SHEPHERD: Fair enough. If -- when you calculate the hydroelectric incentive mechanism, the current one -- I am going to get to the new one in a minute, but let's just deal with the current one, sort of a basis that we understand -- you don't calculate it on a per-station basis, right?

MR. WILBUR: We do.

MR. SHEPHERD: You do?

MR. WILBUR: Well, we have the figures on a per-station basis.

MR. SHEPHERD: But the actual overall calculation is calculated based on the overall average of all your qualified facilities and the overall production per hour, right? That is how the mechanism actually works, isn't it?

MR. WILBUR: Yes, it is.

MR. SHEPHERD: So it's going to be the same number if you do it on a per-station basis or on an aggregate basis?

MR. WILBUR: It is. It will be the same number, yes.

MR. SHEPHERD: You do it on a per-station basis, but the aggregate is going to be the same? All right.

And as I understand it, there is basically two ways you have to increase your incentive under the current mechanism.

One is you can shift production from a low-value time to a high-value time, which is what you are supposed to do.

And the other is you can spill water to reduce your average, right?

MR. WILBUR: Well, we'd have to spill water that qualifies for the SBG variance account.

MR. SHEPHERD: Yes.

MR. WILBUR: Yes.

MR. SHEPHERD: Reducing your average will increase your incentive, right?

MR. WILBUR: Yes.

MR. SHEPHERD: Okay. And that's not what is supposed to happen, and this is the problem that you addressed in your evidence, is that you, in essence, are being incented to spill water at certain times, right?

MR. WILBUR: I am not sure we were being incented to spill water, because we have an SBG variance account. So we get paid for that -- we get paid for that spill.

MR. SHEPHERD: Well, but that's not treated as production from the point of view of the hydroelectric incentive mechanism, right? That's the problem, is you get paid for it as if you produced, but then it's treated as if you didn't produce for incentive-mechanism purposes, which means that you also get -- can increase your incentive from the same thing; right?

MR. WILBUR: The incentive is increased from that.

MR. SHEPHERD: It's a little bit like double-counting.

MR. WILBUR: Yes.

MR. SHEPHERD: All right. And am I right in understanding that the -- that all surplus base load generation spill under the current mechanism will, dollar for dollar, increase your hydroelectric incentive mechanism; is that correct?

MR. WILBUR: No, that is not correct.

MR. SHEPHERD: Okay. So tell us the circumstances in which it will and it won't.

MR. WILBUR: It will if it is seen by the hydroelectric incentive mechanism as time-shifting. So maybe I can turn to an interrogatory response, which, I think it's SEC -- actually, it's not SEC, it's... It's CME. So CME interrogatory 007, so that's Exhibit L, tab 5.4, CME 007, where we -- and if we look at just the first, I guess the first table on page 2, that interrogatory, that basically explains how SBG spill -- in the first -- so there is two cases described there.

In case 1 we do time-shifting and avoid spill, and that results in an HIM, hydroelectric incentive mechanism revenue, and in case 2 we are unable to avoid the spill, and that shows how that -- that also results in a hydroelectric incentive mechanism revenue, and that is what we are proposing to correct with our enhanced hydroelectric incentive mechanism.

MR. SHEPHERD: And you can see the effect there is that what is happening in case 1 is that you are shifting, but in case 2 you are getting the incentive because you reduce your average output.

MR. WILBUR: That is correct.

MR. SHEPHERD: Okay. Although you calculate this on a per station basis, am I right in understanding that -- your stations basically operate as -- I don't mean on a day-to-day basis, but conceptually -- as almost like one generator, so that if you were going to spill at one station -- let's say you were going to spill at Otto Holden. It's an intermediate station. You might get stuck with having to spill there, right? You could -- instead of spilling there, you could pump at Beck and generate at Holden; right? Generally speaking, you can do that.

MR. WILBUR: Well, I guess, generally speaking, there are other factors that are influenced by our pump decision. So, yes, if we decide to pump versus not pumping, that will reduce surplus on the system, which may be seen as reduced spill at our other stations, or it may be seen as a change in dispatch to Bruce Power nuclear units or to wind units.

MR. SHEPHERD: All right. Now, Madam Chair, I am going to go to the second part of my cross, which deals with the newly regulated. Do you want to take a break now, or do you want to push through?

MS. HARE: We will take a break. So we will break until -- well, why don't we make it 1:30.

MR. SMITH: Madam Chair, sorry if I just might just alert, I have been looking at the time estimates, and I just wanted to alert the Board to where we were so that people understand. The estimate for the cross-examination of this panel would have taken us through the entire day and potentially into whenever they had to come back. We are, it looks like, ahead of schedule, but having said that, on the basis of what I understood to be the time, we didn't call the people in Pickering who would be the nuclear panel to come --

MS. HARE: No, no, no.

MR. SMITH: -- so I just wanted people to know that if we do finish early I still won't have them until tomorrow morning.

MS. HARE: We are not going to start the next panel. And I also have been keeping track, and I think we will be done about 3:30 today, depending how many questions we have, and that's fine. We will start the next panel tomorrow.

MR. SMITH: We are on the same page, thank you.

MS. HARE: Thank you.

### --- Luncheon recess at 12:23 p.m.

### --- On resuming at 1:37 p.m.

MS. HARE: Please be seated. Mr. Shepherd, are you ready?

MR. SHEPHERD: Thank you, Madam Chair.

So before I leave surplus base load generation, I do want to ask one other question about that. And that is we know what you are forecasting the surplus base load generation to be in terawatt-hours in the next couple of years. I couldn't find in the evidence anywhere where you tell us, in terawatt-hours, what the past surplus base load generation has been per year, split up between previously regulated and newly regulated.

Can you help us with that? Is that in the evidence, or can you provide it by undertaking?

MR. WILBUR: It is in -- it's in an interrogatory response.

MR. SHEPHERD: We found it in dollars, but we didn't find it in terawatt hours.

MR. WILBUR: It is in here somewhere. Bear with me a moment.

So SEC 132, I believe.

MR. SHEPHERD: Oh, one of ours too? Even worse.

MR. WILBUR: So that's Exhibit L, tab 9.1, schedule 17, SEC 132, And it's attachment 1, table 5.

And this is showing the actual surplus base load generation in gigawatt-hours. That's the first line there, for -- this is only for the currently regulated facilities, because that's all that's applicable to the surplus base load generation variance account.

So you can see for actual for March to December 2011 is 76.5 gigawatt-hours, 117 gigawatt-hours in 2012, and roughly 700-gigawatt hours.

MS. HARE: Mr. Wilbur, just give us a second for this to come up on the screen and for the counsel to the find it.

MR. WILBUR: It's table 5. So the first row, "Actual foregone production due to SBG conditions."

And again, this is only -- this only applies to the currently regulated facilities, because those are the only ones that -- for which this variance account applies.

MR. SHEPHERD: Understood, and so my question is: Do you have similar data for the newly regulated, because you still had SBG, or surplus base load generation, spill in the newly regulated in the past, right?

MR. WILBUR: We did. And yes, we do have this. I know that for 2013, the -- in our annual report, I believe -- maybe it's the MDMA. I am not sure which -- there is a public report where we reported the total surplus base load generation spill for 2013, and I can tell you it was 1.7 terawatt-hours in total. So there was 1 terawatt-hour at the currently non-regulated facilities in 2013.

MR. SHEPHERD: Okay. In 2013, 1 terawatt hour. So can you provide '11 and '12?

MR. WILBUR: I believe we can, yes.

MR. SHEPHERD: Thank you.

MR. MILLAR: J4.4.

UNDERTAKING NO. J4.4: TO PROVIDE SURPLUS BASE LOAD GENERATION FOR NEWLY REGULATED FOR 2011 AND 2012, IN TERAWATT-HOURS.

MR. SHEPHERD: Now, we were talking about this interaction between the surplus base load generation and the hydroelectric incentive mechanism, and you talked to a couple of other cross-examiners about that. I wonder if you could turn to page 11 of our materials.

And you have already been taken to this interrogatory, so I won't go over the same ground. Mr. Millar, I think, asked, and I think maybe IESO asked as well, why you can't just adjust for the surplus base load generation in calculating the hydroelectric incentive mechanism.

And you explain in (a) that it's complicated, but in (b) you say -- and this is what I want to get to -- you say you have proposed a new incentive mechanism -- that's the eHIM, you call it -- that has an identical outcome.

Now, that not actually true, is it? It's not an identical outcome, is it?

MR. WILBUR: My understanding is it is an identical outcome, yes.

MR. SHEPHERD: I thought yours was based on a forecast adjustment. Isn't it? You have a number, you adjust for that number, right?

MR. WILBUR: The enhanced part of the enhanced hydroelectric incentive mechanism is to remove the potential overpayment in the hydroelectric incentive mechanism due to surplus base load generation spill.

MR. SHEPHERD: The forecast potential --

MR. WILBUR: No, but we're -- when we make the adjustment in the surplus base load generation variance account, as we have proposed here, that is all based on actuals; that is not based on a forecast.

MR. SHEPHERD: Okay. Well, you were asked about that by, I think, Mr. Janigan, and I thought you said that you didn't plan to adjust your benefit amount, your X factor, for actuals.

MR. WILBUR: We don't plan to adjust the X factor for actuals. That's correct.

But when we are calculating the revenue that OPG will receive under the enhanced hydroelectric incentive mechanism, that will be based on actuals. That is done after the fact, according to the formulas that are in -- that we have already looked at a few times in E1.2.1.

MR. SHEPHERD: I better come back to that, because I didn't see that that was the result.

If you go to the next page of our materials, this is the list of stations, newly regulated stations that you propose to add to the hydroelectric incentive mechanism; am I right?

MR. WILBUR: That is correct.

MR. SHEPHERD: And the next page, appendix 2, which is page 13 of our materials, are the ones that you propose not to be included in that, right?

MR. WILBUR: Correct.

MR. SHEPHERD: While the reason is because certain of them have a particular type of modelling, the reality as well is that all of your peaking and intermediate facilities and all of your large facilities are on the first list, right?

MR. WILBUR: With the exception of one, yes.

MR. SHEPHERD: With the exception of one, being Eugenia, which is, like, 6 megawatts; right?

MR. WILBUR: Correct, but it is an intermediate facility, as opposed to a run-of-river facility.

But really the main reason that we're -- another substantial reason why we are proposing not to include those is also that the IESO does not see the output of these stations, and therefore cannot do the settlement of the -- would not be able to do the settlement of the hydroelectric incentive mechanism revenues.

MR. SHEPHERD: I understand. So just -- if you look at page 12 -- tell me whether this is right -- you have -- on the Madawaska River, you have four of the five, all but Kalabogie, are peaking facilities, and they total 610 megawatts, right? Will you accept that, subject to check?

MR. WILBUR: That sounds about right.

MR. SHEPHERD: I just took it from your list, which is on pages 14 and 5.

MR. WILBUR: Yes, subject to check, that is...

MR. SHEPHERD: And on the Ottawa River, you have three that are intermediate facilities, your only three intermediate facilities on this list, and they total 816 megawatts, right? Otto Holden, Des Joaquims and Chenaux?

MR. WILBUR: Yes. That sounds -- that's close, yes.

MR. SHEPHERD: An on the Abitibi and Montreal Rivers –- Montreal is upstream from Abitibi; is that right? Lower Notch is upstream from the Abitibi River?

MR. WILBUR: I think they are separate rivers.

MR. MAZZA: Yes, separate rivers.

MR. SHEPHERD: Okay. Anyway, those the three total 805 megawatts, and they are also peaking facilities, right?

MR. WILBUR: Yes. Sounds reasonable.

MR. SHEPHERD: What I get -- and tell me whether this is right -- you have seven peaking facilities totalling 1,415 megawatts, and you have, in this list, excluding Eugenia, you have three intermediate facilities, all on the Ottawa River, totalling 816 megawatts. Will you accept that?

MR. WILBUR: Yes.

MR. SHEPHERD: So that's 2,231 megawatts, which in --you said earlier it was 2,100, but it's actually 2,231; isn't that right?

MR. WILBUR: My rough addition this morning came up to 2,100.

MR. SHEPHERD: Understood. I am not trying to rag you. I am just trying to get it clear.

The rest of the ones on appendix 1 are all run of the river facilities; right? And they total about 760 megawatts.

MR. WILBUR: Sure, that sounds reasonable.

MR. SHEPHERD: Okay. Now, on the peaking facilities I think you have agreed the peaking facilities are ones in which you run to peak; right? You are trying to -- in fact, you have ones like Abitibi Canyon that have quite a lot of storage; right?

MR. WILBUR: Correct. A number of those facilities have a lot of storage, yes.

MR. SHEPHERD: So your intention is to run them to maximize your production at peak times; right?

MR. WILBUR: That is correct.

MR. SHEPHERD: And the way you do that is you -- you have a certain amount of water, so you do have to use the water sooner or later, but you target so that the water is only used as much as possible at the high value times; right?

MR. WILBUR: Correct.

MR. SHEPHERD: So this is not like a gas facility. We have gas peaking plants. Gas peaking plants run when peaking power is needed, but when it's not needed they don't need to store the gas anywhere. They just don't run; right?

MR. WILBUR: Correct. They are not --

MR. SHEPHERD: This is different. You actually have to produce a certain amount.

MR. WILBUR: Yeah, they are not energy limited facilities. We would call these energy limited facilities.

MR. SHEPHERD: All right. Intermediate also are facilities that have storage, in the sense that they have a dam, and so they have some form of reservoir, but it's not as much, particularly because they are on the Ottawa River, it's a navigable river, you have restrictions; right?

MR. WILBUR: Correct.

MR. SHEPHERD: So there is only so much you can store water before you screw up navigation on the river.

MR. WILBUR: There are rules and regulations about how much water has to be passed and so on, which changes from time to time and from season to season.

MR. SHEPHERD: But you still have the ability to follow load to a certain amount with intermediate facilities, and --

MR. WILBUR: We do, yes.

MR. SHEPHERD: Okay. And then these other facilities on the list -- correct me whether I am right -- they all still have dams; right?

MR. WILBUR: They do.

MR. SHEPHERD: Do you have any facilities that don't have dams that are pure run of the river?

MR. WILBUR: I believe all of our facilities have dams.

MR. SHEPHERD: Yes. So because they have dams, there is still a certain amount of storage that you can do, a certain amount of control over when the water goes through your turbine; right? It's limited, but there is some?

MR. WILBUR: That is correct.

MR. SHEPHERD: And you do that.

MR. WILBUR: And we do that.

MR. SHEPHERD: So in the same way as you do it with Saunders, where you are very restricted, but you still can do it a little bit.

MR. WILBUR: Yes.

MR. SHEPHERD: Okay. And one of things I wanted to find out is -- and perhaps we can turn to this exhibit that was filed today by IESO, which is K4.1. Do you have that? I am looking at the last page, which is a 12-month summary of output relative to hourly Ontario energy price; right?

MR. WILBUR: I have that, yes.

MR. SHEPHERD: And as you were saying earlier, it's clear that your newly regulated facilities fairly closely follow the price.

MR. WILBUR: I believe it's clear that the currently regulated and the newly regulated closely follow the price.

MR. SHEPHERD: I am not worried about the currently regulated right now. Just --

MR. WILBUR: Okay.

MR. SHEPHERD: -- I am just talking about the newly regulated. To the extent that the shape of the line of the newly regulated is not exactly price, that's inefficiency on -- it's operating inefficiency, right? It may not be something you can control, but the perfect efficiency would be if you followed the price exactly.

MR. WILBUR: No, I wouldn't agree with that. I think that what we -- the level of the price in any particular hour -- the absolute number of the price is not particularly important, I don't think. What is important is that during the highest-price hour or hours, are we generating the most?

MR. SHEPHERD: Okay.

MR. WILBUR: So I think it's more important to look at the shape and compare the two shapes and see that they do coincide pretty closely.

MR. SHEPHERD: Now, we saw the other day that your average price that you got in 2013 for your newly regulated facilities -- actually, no, for what were then your unregulated facilities was $28 a megawatt hour. Do you recall that? It's from your annual report.

MR. WILBUR: Okay.

MR. SHEPHERD: And I just looked at the website of IESO to find out what the average hourly Ontario energy price was for the same period, and it was 27, and I thought that seems strange, that your average price would be so close to the average price in the market for the year. That shouldn't be, should it? You should be getting a higher average price than the average in the market?

MR. WILBUR: Well, our production weighted average price will be higher than the market price.

MR. SHEPHERD: Well, but your production weighted average price was 28 and their price average was 27. That is what I don't understand. I am trying to get an understanding of that.

MR. WILBUR: I'm not -- I was not actually at the hearing on that day, and I am not aware of where that price came from, so...

MR. SHEPHERD: All right. Well, here is what I am going to ask you to do. I am going to ask you to take a look at this -- at the 2013 -- your 2013 actual data, and I am going to ask you to calculate, if the existing hydroelectric incentive mechanism had been applicable to your newly regulated facilities, what would the amount of the incentive have been? It's just a mathematical calculation, right? You take your production data, you calculate it through, just as you would with the previous year. You can do that, right?

MR. WILBUR: I believe we can. I am not certain how much effort is required to do that, but I believe it can be done.

MR. SHEPHERD: Okay. Thank you. Because it looks like it would actually be low. If your average was 28 and you -- and the average in the market was 27, it looks like your hydro incentive mechanism would be low, and that doesn't seem right for this type of facility. That is why I am asking you to do the calculation.

MR. MILLAR: J4.5.

UNDERTAKING NO. J4.5: TO LOOK AT THE 2013 ACTUAL DATA AND CALCULATE, IF THE EXISTING HYDROELECTRIC INCENTIVE MECHANISM HAD BEEN APPLICABLE TO THE NEWLY REGULATED FACILITIES, WHAT WOULD THE AMOUNT OF THE INCENTIVE HAVE BEEN.

MR. SMITH: Yes, we'll do that. If we do have any further information about the effort, I will report back, but we should take it as an undertaking.

MS. HARE: Thank you.

MR. SHEPHERD: All right. And I hate to say it, Madam Chair, but I think that's it.

MS. HARE: Are you done, or you are just shortening?

MR. SHEPHERD: I am done.

MS. HARE: Thank you very much.

So Mr. Thompson, you are next.

## Cross-Examination by Mr. Thompson:

MR. THOMPSON: Yes, thank you, Madam Chair.

Panel, I don't have a lot left, but I do see from the responsibility for issues on the witness panels and evidence responsibilities document that you have responsibility for issues 5.1a, 5.2, 5.4, 6.1, and 6.2; is that correct? Would you take that subject to check?

MR. MAZZA: Yes, we will take that subject to check.

MR. THOMPSON: Thank you.

And issue 5.1a is one I just wanted to ask you a couple of questions about. It is, could the storage of energy improve the efficiency of hydroelectric generating stations. And there was an article in the recent edition of The Economist that spoke to that very issue, and Mr. Tolmie in this case had submitted some data on the issue.

What is OPG's answer to that question?

MR. MAZZA: If you mean storage of energy as it relates to pump storage -- is that what you mean, or does it relate to something else?

MR. THOMPSON: What does this question mean to you?

MR. MAZZA: Well, I take it as meaning pump storage, can storage of energy using pump storage facilities improve the efficiency.

MR. THOMPSON: Okay. And what is the answer to the question?

MR. MAZZA: Well, pump storage is really not there to improve the efficiency of a particular station. What we do in our business to improve the efficiencies of our station is we upgrade our runners to make them more efficient, which, we've had a program to do that. And that's the extent that we look at it, from an efficiency standpoint.

MR. THOMPSON: Well, is that it? Is that what OPG is doing about this issue at the moment, or is there something broader than that?

MR. MAZZA: So -– yeah, so from an energy efficiency point of view, I pointed out that we have upgraded our turbines, and we have a program to do that and we have since 1992. And that's well underway and reaching completion.

The other thing we have looked at is some other pump storage facilities, and we have submitted the information to the OPA specifically with respect to one pump storage facility, but that's the extent of the studies that we have done.

MR. THOMPSON: Okay. Thank you.

Now, the next issue is:

"Is the estimate of surplus base load generation appropriate?"

Mr. Shepherd has discussed that with you, and what I now understand from your discussion with him is that your estimate of surplus base load generation for the test period is 2.1 terawatt-hours; have I got that straight?

MR. WILBUR: I believe we took an undertaking to produce that. That was an estimate.

MR. THOMPSON: Okay. Well, I think you said it sounded reasonable, so let's leave it there for the moment.

And he also suggested to you that has a cost of -- I think the net amount was in the order of $80 million, and I thought you said that sounded reasonable.

MR. WILBUR: That is subject to check.

MR. THOMPSON: Okay. And so is surplus base load generation a fancy way of saying waste, that we are wasting this electricity -- hydroelectric generation potential?

MR. WILBUR: When we spill water due to surplus base load generation conditions, that water is, as we have stated in evidence, irrevocably lost. So that could be considered waste.

MR. THOMPSON: Thank you.

Now, the evidence speaks of conditions in the Ontario market, and it talks about current, I think, and future conditions in the Ontario market. Now, what are the conditions in the Ontario market that are producing, operating to produce this waste situation?

MR. WILBUR: Well, the conditions that are leading to surplus base load generation are basically -- the amount of base load generation on the power system at this time is more than is needed at a lot of times, and this -- it is partly due to the change in the economy that we have had in Ontario since 2008, which has reduced -- which has reduced the base load demand for electricity.

MR. THOMPSON: Okay. So is it simply over-supply? Is that what you are saying? Or are there other factors in the market that are operating to produce this?

And what I would also like to find out is what is your prognostication as where we are headed with this phenomenon.

MR. WILBUR: I think it is -- it's over-supply, but over-supply of what is considered base load generation. So there is base load generation, there is intermediate generation, there is peaking generation. And I don't think that we have a significant surplus of the total generation that we need right now, but there is a surplus of the base load generation.

So the base load is the generation that is more difficult to reduce or impossible to reduce as demand falls.

MR. THOMPSON: Now, does solar and wind fall within the base load generation category?

MR. WILBUR: Yes. We consider them to be base load, yes, variable and base load.

MR. THOMPSON: And anything else, other than hydroelectric and nuclear? Is there some gas generation in there too that's base load?

MR. WILBUR: There may be some gas generation that's base load, but that's not typically -- there may be some gas generators that are operating around the clock regardless of price. I am not completely aware of that. If that's what they are doing, then that would be part of base load.

MR. THOMPSON: Okay. So from OPG's perspective, then, it's hydroelectric, nuclear, solar and wind?

MR. WILBUR: Yes.

MR. THOMPSON: Okay. That, then, brings me to the next issues here, which are the incentive mechanism issues, which you have been talking to others about at considerable length. But I am a senior citizen; I want to make sure I understand this. And so let me start with this.

Is the purpose of the incentive mechanism to prompt OPG to optimize the value of its generation, hydroelectric generation?

MR. WILBUR: I would say that -- well, actually if I go to evidence, E1.2.1, Exhibit E1.2.1, page 6 of 15, section 5.1, and this first sentence is actually taken from the Board decision in our -- EB-2010-0008 decision:

"The purpose of the hydroelectric incentive mechanism is to provide OPG with an incentive to operate its regulated hydroelectric facilities in a way that benefits consumers."

MR. THOMPSON: Right. And is that not the same, the same thing as optimize the value of the system?

MR. WILBUR: Well, it's optimize the value or a specific part of the value, which is the part associated with time shifting.

MR. THOMPSON: Okay. So let me move on. And I just want to understand operationally what prompts those who operate the system to time shift.

I sort of get the picture, that if you didn't have this incentive, your operators would be sitting there with their feet up on the desk, reading comic books.

[Laughter]

MR. THOMPSON: And this thing would be running on just 200 -- whatever it is a day, day in and day out. So help me with what motivates people to time shift.

MR. WILBUR: Well, first of all, there wouldn't be anyone sitting up with their feet on their desk if we weren't doing this. There would still be operations to undertake.

But we have what we call an offer strategy, which dictates how we create our offers that are put into the market for all of our generation. And built into that offer strategy is the principle of time shifting.

And the operators are looking at the current prices and their expectation of future prices in making their offers, to take advantage of -- to use time shifting to follow the markets.

MR. THOMPSON: Now, how -- when did this incentive mechanism come into force? Is it fairly recently?

MR. WILBUR: Well, there has been an incentive mechanism since 2005, since we were first re-regulated, and -- but I believe the -- the 2007, EB-2007-0905, that's when the -- this form of hydroelectric incentive mechanism came in place.

MR. THOMPSON: And prior to 2005, were the operators doing time shifting?

MR. WILBUR: They were doing some time shifting, yes.

MR. THOMPSON: Would they have been doing it to the same degree as they do it now?

MR. WILBUR: I don't believe that if we look -- I have seen results from -- or analysis of our PGS operation from that time and compared with before that time, before the market opened and with -- after the regulation came in 2005. And there was less time shifting done in that period.

MR. THOMPSON: Materially less or marginally less?

MR. WILBUR: I am not sure what it was.

MR. THOMPSON: Okay. So what I would like to do is just understand the way it works now and then move from now to your proposal.

And so in terms of the generation of the incentive, I believe you described that, what leads to an incentive, you describe that at E1, tab 2, schedule 1, page 7 at lines 8 to 13, and you have described this in your answers to others.

MR. WILBUR: That is where we describe the -- we're describing the interaction between the hydroelectric incentive mechanism and surplus base load generation.

MR. THOMPSON: Well, it tells us how the incentive component of HIM is calculated.

MR. WILBUR: Yes.

MR. THOMPSON: And an incentive is generated, as I understand it, where the output profile is such that the monthly hourly output is above the average hourly output in a month; is that right?

MR. WILBUR: Well, it's both when it above and when it's below.

MR. THOMPSON: Okay. But to get into a positive position you have to have more above than below. Have I got that straight?

MR. WILBUR: Actually, it's the quantity of generation times the price of the -- so it's sort of the area of the curve above versus the area of the curve below, in terms of quantity of energy times price, that has -- the positive side needs to be greater, yes.

MR. THOMPSON: Okay. So I am with you there so far.

And so -- and that profile can be produced in two ways, and maybe more. One is where you actually shift load from a lower value time to a higher value time and sell it; right?

MR. WILBUR: So we buy it at the lower value time and sell that same energy back at the higher value time, and that creates a positive incentive, yes.

MR. THOMPSON: And then the other situation is where there is a spill that produces the same type of load profile, but you are not actually, in my parlance, you are not actually generating output. Have I got that straight?

MR. WILBUR: The effect of SBG spill will tend to lower the average and result in an unintended hydroelectric incentive mechanism revenue, and that is what we are proposing to correct with the enhanced hydroelectric incentive mechanism.

MR. THOMPSON: Okay. I will get to that in a minute.

Now, in terms of the tracking of when an incentive amount is going to be paid, am I correct that the IESO does that? In other words, it determines when these conditions in lines 8 to 13 on page 7 of the exhibit are met.

MR. WILBUR: Yes, the IESO has the outputs of our facilities that are involved in this calculation, and obviously the price -- the price information. So they do the -- they have all the information to do the calculation, and they do it, yes.

MR. THOMPSON: But the IESO has -- am I correct -- does not have the SBG information. That's OPG information; is that fair?

MR. WILBUR: That is correct. The IESO does not have the surplus base load generation spill information.

MR. THOMPSON: Okay. And so the -- is this incentive payment that you get from the IESO something that you get every month? Is it part of the clearing processes?

MR. WILBUR: It is, yes.

MR. THOMPSON: Okay. So if you get an incentive payment in a particular month, then you take half of it for OPG based on the existing method, as I understand it, and half of it goes into the incentive mechanism account -- deferral account?

MR. WILBUR: Yes, that's correct.

MR. THOMPSON: Okay. And I understand that you are able to now determine the portion of what's recorded in the incentive mechanism deferral account which is attributable to SBG.

MR. WILBUR: The portion that's due to the surplus base load generation spill, yes.

MR. THOMPSON: So you know what that amount is in the incentive, what portion of the incentive amounts recorded in that deferral account are attributable to surplus base load generation.

MR. WILBUR: Correct. That's as described in the equation on the top of page 13 of E1.2.1.

MR. THOMPSON: Okay. Well, does that equation apply to the now, except for this X factor word that you have down below?

MR. WILBUR: I am not sure what you are asking.

MR. THOMPSON: Well, I am talking about the now situation. I initially understood this was your proposal at page 13, but now I hear you saying it is descriptive of what's happening now.

MR. WILBUR: No, that's not what's happening now.

MR. THOMPSON: Okay. Well, I am talking about what's happening now.

MR. WILBUR: Okay. I will need you to repeat your question about surplus base load generation spill, because I am not understanding how that relates to the now.

MR. THOMPSON: You get a payment from the IESO for an incentive for every month, and what I asked was, can you determine the portion of that payment that's attributable to surplus base load generation? I understood you to say, yes, we can.

MR. WILBUR: We could, and it would be done by using that formula that's later on, that's on page 13.

MR. THOMPSON: Okay. And so -- and 50 percent then of that revenue received from the IESO goes into the incentive account and 50 percent goes to you; right?

MR. WILBUR: Well, actually, there is a revenue requirement offset, so 100 percent of it goes to us until we get to double the revenue requirement offset, and then it would be -- and then the remainder above that 50 percent goes into the hydroelectric incentive mechanism variance account.

MR. THOMPSON: Thanks for that clarification. And what is the amount embedded in the revenue requirement at the moment?

MR. WILBUR: It's in our evidence here somewhere. So the threshold for 2013 was set at 13 million.

MR. THOMPSON: Thank you.

MR. WILBUR: So that's on the previous page, page 5 of E1.2.1, line 24.

MR. THOMPSON: Okay. And so that's the incentive mechanism deferral account. And then you also have a surplus base load generation variance account. Am I right?

MR. WILBUR: That's correct, yes.

MR. THOMPSON: And this is something OPG calculates. You do your -- you determine what's surplus base load generation in the manner you have described to others, and then it gets posted to the variance account based at, I assume, the Board-approved payment amount. Is that the multiple there?

MR. WILBUR: Yes, that would be, yeah.

MR. THOMPSON: And so that has a bucket of dollars in it, and am I right that the dollars in that account do not get cleared and paid for by ratepayers until this Board issues an order clearing that account?

MR. WILBUR: That's correct. I believe that's the case for all of our variance and deferral accounts.

MR. THOMPSON: Okay. So at the time that you apply to the Board to clear that account, why can't you simply do the adjustment to the dollars recorded there to reflect the double-dipping? I think you said you could do it. My question is, why don't you do it that way? It seems to me to be extremely simple.

MR. WILBUR: I don't believe that would be following the decision from the last -- our last rate case.

MR. THOMPSON: Well, why not?

MR. WILBUR: Because it directs us as to how we are to calculate these variance accounts, and I don't -- and it doesn't tell us to do that.

MR. THOMPSON: Well, is that what you need to be told to do? I would have thought anybody who came across a situation where you are having this double-dipping unintended consequence would have said, Well, we've got to correct that when we clear that SBG variance account, but you folks don't do that; is that right?

MR. WILBUR: We are not proposing to do that in this application, no.

MR. THOMPSON: But are you proposing to do it when you clear what's in that SBG account now?

MR. WILBUR: In this application, we have identified that problem, and we have proposed an enhanced hydroelectric incentive mechanism, which corrects that problem going forward.

MR. THOMPSON: But you don't need that correction, is all I am saying. You can do it very simply by clearing it out -- by making the adjustment when you clear out the SBG variance dollars?

MR. WILBUR: And that is what we are proposing to do going forward.

MR. THOMPSON: Well, why aren't you proposing to do it with what's in there now? It's an unintended consequence, where you are recovering more than anybody intended.

MR. WILBUR: We don't believe that would be following the Board's instruction from the last decision.

MR. THOMPSON: All right, well...

In terms of solving the problem going forward, that is a solution that works, what I have just described? The Board simply tells you to make the adjustment when you clear the SBG variance account balances. You will then do it; is that right?

MR. WILBUR: That is what we proposed in evidence here.

MR. THOMPSON: Well, I don't think you have, but we will come to that in a minute.

But if the board simply said: Do it this way, you would do it; have I got that straight?

MR. WILBUR: We have proposed exactly that.

MR. THOMPSON: All right. Let me move on.

And that amount that gets posted to the -- sorry, the amount that gets posted to the incentive variance account is 50 percent of the incentive payment you receive from the IESO, right? That's the way it works now?

MR. WILBUR: Correct.

MR. THOMPSON: It's 50 percent of a revenue amount, right?

MR. WILBUR: That is correct.

MR. THOMPSON: And you said earlier that -- and you don't need to change that to solve the double-dipping problem, do you?

MR. WILBUR: And we are not.

MR. THOMPSON: Well, I think maybe you are, because you told a previous questioner that you're changing from revenue sharing to a benefits sharing, right? That's a change?

MR. WILBUR: And that's not related to the change we are making to correct the unintended revenues due to surplus base load generation spill.

So there are two distinct changes we are making in this enhanced hydroelectric incentive mechanism.

MR. THOMPSON: All right. Well, one of them has nothing to do with the surplus base load generation double-dipping problem?

MR. WILBUR: That's correct.

MR. THOMPSON: Okay. And that is, if I understand this evidence correctly -- I am now looking at page 6 of E1, tab 2, schedule 1, where in line 17 you make a reference to table 2.

And now what you have said is:

"Table 2 shows OPG's forecast of changes in ratepayer costs deriving from the three factors above for the test period."

This has got nothing to do with your forecast of incentive revenues that you would recover from IESO, has it?

MR. WILBUR: It does not.

MR. THOMPSON: Okay. So then you show the forecast and changes of customer costs, and then you go on and say this is what you're forecasting by way of reduction in customer costs in the test period, right?

MR. WILBUR: Yes.

MR. THOMPSON: You're forecasting there will be a total reduction in customer costs of 36 million in the test period?

MR. WILBUR: 36 million per year in the test period, yes.

MR. THOMPSON: Oh, per -- so 72 all together? Okay.

And that's different from forecasting the revenues you would have received from the IESO in each year from the incentive payment mechanism?

MR. WILBUR: That is different, yes.

MR. THOMPSON: Okay. And then we go over to a little bit later, where you are talking about how you derive the 35 percent -- this is now on page 13 -- the 35 and 31 percent, and you say:

"The X factor appearing in the incentive payment and in the incentive payment adjustment formula is established such that the net incentive retained by OPG is equal to one-half the customer cost reductions shown in table 2."

Right?

MR. WILBUR: That's correct.

MR. THOMPSON: Again, that number is not 50 percent of the forecast revenues that you expect to receive from the IESO by way of an incentive mechanism? It's a different calculation, right?

MR. WILBUR: It is.

MR. THOMPSON: So what is the forecast of the incentive revenue that you expect to receive from the IESO for 2014 and 2015?

MR. WILBUR: We have that in an interrogatory response, which -- you will have to bear with me while I determine which one it is.

So that's -- it's in SEC 73, so it's Exhibit L, tab 5.4, schedule 17, SEC 073.

MR. THOMPSON: And the number is?

MR. WILBUR: There is a table on page 2 of that, which shows that the incentive payment would be 78 million in 2014.

MR. THOMPSON: And what is it in --

MR. WILBUR: 96 million in 2015.

MR. THOMPSON: 78 and 96 million? Okay.

MR. WILBUR: Now, that is without the X factor applied.

MR. THOMPSON: Yeah, I am just doing this the old way. So if you did it the old way, there would be some amount embedded in rates, right? Let's say it's, for the sake of argument, $20 million, right?

And then everything that you received above the 20 million would be split 50/50?

MR. WILBUR: I think actually it would be everything above double the 20 million, so above 40 million. In your example, it would be 40 million.

MR. THOMPSON: 40 million would be embedded in rates?

MR. WILBUR: No. If 20 million was embedded in rates, then once we have achieved a revenue of 40 million, then we would be splitting it 50/50.

MR. THOMPSON: Oh, I am sorry. Correct.

MR. WILBUR: Then everything beyond that, we would continue to split 50/50 by way of the variance account.

MR. THOMPSON: Okay. Good. And to the extent you were over 40 million, it would -- the actuals would be split 50/50 between OPG and the ratepayers?

MR. WILBUR: Correct.

MR. THOMPSON: To the extent you are under 40, is this symmetric or can you --

MR. WILBUR: If it was under 40, then we wouldn't achieve a 50/50 split. We would get -- OPG would get less than 50 percent.

MR. THOMPSON: Okay. So that's the current mechanism.

So if it achieved the $78 million forecast, then what ratepayers would get would be the 20 million plus 19, right? Half of 38?

MR. WILBUR: Yes.

MR. THOMPSON: And then in 2015, they would get half of 96, which would be 48 million, right?

MR. WILBUR: Yes.

MR. THOMPSON: If you achieved your forecast.

And so what's wrong with sticking with that approach?

MR. WILBUR: Well, that's -- the approach we took, as we were directed by the Board in the last decision, was to do a comprehensive analysis of the benefits to consumers

of the time-shifting that we do, and that's what we have done and determined that that consumer benefit is 36 million per year. And then we have -- and then it's a matter of -- so the consumers are benefiting to the tune of 36 million due to the time-shifting, and yet we would like to receive some incentive for that, so -- and we -- we chose 50 percent.

So we figure -- we decided it was appropriate that we get 50 percent of that benefit, so if --

MR. THOMPSON: Let me --

MR. WILBUR: -- the consumers benefit by 18 million and we benefit by 18 million as well.

MR. THOMPSON: Let me ask you this: Assume that the incentive revenue is 78 million in 2014 and 96 million in 2015. What is the ratepayers' share under your approach -- proposed approach?

MR. WILBUR: I am not sure what you mean. I think one thing you are missing here is that the 78 million and the 96 million, that is entirely paid for by consumers. They pay that, and then the 50/50 share is giving some of that back.

MR. THOMPSON: I don't think I'm missing anything. I wanted to find out under your proposed approach, assume 78 million in 2014 and 96 million in 2015. What is the ratepayers' share in each of those scenarios?

MR. WILBUR: Well, the ratepayer doesn't pay the 78 million or the 96 million, as they would in the scenario you have described. The ratepayer will pay us 18 million in each year, which is at the bottom of this table in SEC 073, and the consumers will also benefit to the tune of 36 million from the time-shifting via reduced global adjustment charges.

MR. THOMPSON: Well, I am trying to get a -- can you give me a comparative analysis to show me that ratepayers and consumers are better off or worse off under what you are proposing? This is where I think people are losing it here. We can't make the comparison, because they are two quite distinct methods.

MR. WILBUR: Consumers are paying quite a bit less under our now proposal.

MR. THOMPSON: Explain that, how that works.

MR. WILBUR: Well, because under the old proposal the consumers -- the 78 million and the 96 million comes from consumers. The IESO does this calculation, and it determines that OPG is owed this incentive revenue, and that is added to the bills of consumers. So the consumers are paying that 78 and the 96. And then through the variance account we would be returning some portion of that, 50 percent of it, if our forecast was in that.

What we are proposing now is consumers will only pay 18 million to us through this. So the IESO will do a calculation, if our forecast is correct, the IESO's calculations every month will add up to 18 million over the year, and that is what will get added to consumers' bills.

MR. THOMPSON: And is that all you get in each year?

MR. WILBUR: Yes, that is all we get.

MR. THOMPSON: It's fixed at 18 million?

MR. WILBUR: Well, if our forecast is correct, that is what we get.

MR. THOMPSON: All right. So the forecast -- is the forecast that -- all right. So what happens -- just help me. What happens if your forecast is -- reduction is greater than what you forecast? Does it turn on production?

MR. WILBUR: No, it turns on incentive revenue.

MR. THOMPSON: All right. And so the forecast for incentive revenue was $78 million, correct, in --

MR. WILBUR: Yes, in 2014, yes.

MR. THOMPSON: And consumers are going to pay 18 million for that?

MR. WILBUR: No, the 78 million is just the result of an equation. It's not -- there isn't actually a pot of $78 million sitting somewhere, okay? The IESO will do this calculation every month and pay us an incentive revenue, and if our forecast is correct that payment will be 18 million.

MR. THOMPSON: Okay. And so what's wrong with what I said? If your $78 million forecast is correct, the IESO will, in applying your formula, will cough out 18 million.

MR. WILBUR: That's correct.

MR. THOMPSON: Okay. And if your $96 million forecast is correct, 2015, you have given the IESO a different X factor number, I guess, for his number -- let me back up.

What you are giving the IESO now is a percentage amount that they are going to apply in their formula.

MR. WILBUR: Right. So they have this formula that they calculate every month, and there will be an X factor that is in that formula, and that changes from year to year.

MR. THOMPSON: And you are going to give them that based on what this Board decides; is that right?

MR. WILBUR: That's correct.

MR. THOMPSON: This Board has to decide that percentage.

MR. WILBUR: It does, yes.

MR. THOMPSON: That goes to IESO, and you apply it in 2014, the 78 million, the number that should fall out of it is 18 million?

MR. WILBUR: Correct.

MR. THOMPSON: And if you apply it, the 96 million, in 2015, the number that should fall out of it is 18 million.

MR. WILBUR: Correct.

MR. THOMPSON: So the benefit of what you are doing is it's not for ratepayers as such, it's for electricity consumers; is that the difference?

MR. WILBUR: Is there a difference?

MR. THOMPSON: Maybe not.

MS. HARE: No, Mr. Thompson, I didn't understand the question either. You said, is there a difference for ratepayers or electricity consumers.

MR. THOMPSON: Right.

MS. HARE: Is that what you meant to say?

MR. THOMPSON: That is what I -- well, payment? That is what I thought I meant to say, yeah. Help me.

[Laughter]

MS. HARE: I can't help you.

MR. THOMPSON: Okay. There we go. I guess they are the same. All right. Okay. So that's as clear as mud.

Let me move on. Well, just before we move on, what does OPG see as the disadvantage of leaving it the way we had it? Is it that it's going to cost ratepayer/consumers more?

MR. WILBUR: Yes, actually, it doesn't address the Board's concern about what -- the benefits to consumers of our time-shifting, whereas our proposal does.

MR. THOMPSON: Thank you. Let me move on then to just a couple of other issues on this list of your responsibilities. One was -- well, they relate to OM&A, which has been canvassed by others, and then benchmarking. I just have a couple of questions about benchmarking.

Now, yesterday I filed a compendium, K3.6, and at tab 1 of that compendium there is the memorandum of agreement between OPG and the Crown in Right of Ontario. Paragraph -- or section C(1) talks about performance targets being set by OPG. And then it goes on -- or the agreement goes on to say:

"These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America."

Now, are you folks familiar with that provision of the memorandum of agreement?

MR. MAZZA: Yes, I am familiar with it.

MR. THOMPSON: And you have had a lot of exchanges with others about what you do and what you don't do with respect to benchmarking, but the question I would ask is this: By what amount would the hydroelectric revenue requirements in 2014 and '15 decline if OPG was in the top quartile of electricity-generating companies in North America? Can you help us with that question?

MR. MAZZA: That amount would be difficult to calculate off the cuff, but all I can say is if you go to our evidence, which we have presented our benchmarking data, if you go to F-1, tab 1, schedule 1 and page 13 -- sorry, that's the availability benchmarking. I apologize for that.

Go to page 19 and 20, 19 being the previously regulated assets and 20 being the newly regulated assets.

If you look at that information, you will see that a majority of our plants benchmark in the top two quartiles and a significant portion benchmark in the top quartile.

So when you have a fleet of 54 stations, we have small stations, large stations; on the whole, they do benchmark in the top quartiles.

And we have presented this data to our board and we have presented it as well to the shareholder in the past, and they were satisfied that, on the whole, we were performing amongst the top utilities in North America.

MR. THOMPSON: Okay. But just looking at this on the screen, and so the top quartile is between zero -- well, it's got Q1, Q2, Q3, Q4; are those the quartiles you're talking about?

MR. MAZZA: Yes, those are the quartiles.

MR. THOMPSON: Okay. And so it looks like three segments are in the top quartile and two segments of the enterprise are not in the top quartile; have I got that right?

MR. MAZZA: There is -- yeah, there is three stations in the top quartile. There is one station, Sir Adam Beck, in the second quartile. And there is the Sir Adam Beck PGS in the fourth quartile.

MR. THOMPSON: And we don't have all of the others that you're --

MR. MAZZA: Well, that's for previously regulated. So when you look at the previously regulated -- and we have a note there. 99 percent of the energy that these facilities produced are, over the three-year period, in the top two quartiles.

MR. THOMPSON: But top two is not good enough; it is supposed to be in the top quartile?

MR. MAZZA: The way this has been interpreted is the mandate that was developed, that we -- like I said, we did present this information in the past, and our board was satisfied with -- that we were demonstrating the top quartile performance.

MR. THOMPSON: Well, my question is really posed to what this Board might be inclined to do, which is to attempt to determine what the revenue requirements would be if you met that benchmarking standard.

And from what I have gathered in your discussion with others, you really don't have -- there is no information that you have provided to help with the answer to that question, is there?

MR. MAZZA: Could you...

So in essence, as I have explained before, we use benchmarking to look at making efficiency improvements. That is part of the exercise. Actually, I feel that that is probably the more important part of the exercise, because when you talk to other utilities and you see what they are doing to demonstrate, I guess, efficiencies, you share that information across the utilities. So that's one part of it.

But as I have stated, I think when you look at it in totality, we are amongst the top in the benchmarking that you see there. When you go to the newly regulated, there is a similar trend there.

The other thing we presented to our board, if you go to our evidence, F1, tab 1, schedule 2, there is a chart there. If you could go to that -- sorry, it's schedule 1, page 25 of 28.

So when we look at a fleet that we have, we have to categorize our fleet into asset classes. So there are some parts of our asset classes that, you know, if you will, are of higher value. So you would focus on those to ensure -- and then there is some assets that are of lower value, and you have to be strategic on how you invest in the assets and what availability targets you use.

So when we looked at this in totality and compared it to other utilities -- and other utilities may not use the same approach, but we felt that we were in that top quartile range, if you will. We are probably one of the only utilities as well that benchmarks a lot of their facilities.

So, I mean, in answer to your question, we feel that we are there.

MS. HARE: I don't think you answered Mr. Thompson's question, which is an interesting one, which is: If you actually were in the top quartile, would that make a difference to the revenue requirement that you are seeking today? Is that your question, Mr. Thompson? Yes.

MR. MAZZA: And I can't answer that question here on the stand. All I've said is a large portion of our generation is in the top quartile. If we did an assessment of the other portion of the generation to try and make it into the top quartile, there might be some benefit there, but I can't answer the question on the stand. I don't have an answer to it.

MR. THOMPSON: My last question, then, on this benchmarking area -- and it, again, goes to this document I filed yesterday, K3.6, and the Auditor General's report is there at tab 20. I am sure this was -- this is something you folks will be familiar with, but if you go to the -- it's page 154 of the report.

Starting there, there is a series of bullet points describing OPG's behaviour, which isn't terribly flattering, I must say. And then the next page has a summary of OPG's response -- sorry, the next tab, excuse me, 21, has attached to it, as I understand it, OPG's response to the Auditor General's report; do I understand that correctly?

MR. MAZZA: I am not familiar with this particular response here. It wasn't part of what we were reviewing, our issue.

MR. THOMPSON: Okay. Then let's go back to the Auditor General's report just briefly.

Do a number of these criticisms apply to the hydroelectric side? Have you looked at these before? "Top-heavy organization"? "Rehiring former employees"?

MR. MAZZA: I have read the report in the last year, but you need to get into more specific questions as opposed to general questions.

MR. THOMPSON: Well, the first bullet point says that it's a "top-heavy organization." Is hydroelectric subject to that criticism?

MR. MAZZA: I don't think hydroelectric is.

MR. THOMPSON: You are not top-heavy? It talks about rehiring former employees and paying them incentives and all the rest; is that going on in hydroelectric?

MR. MAZZA: The practice of rehiring former employees is not -- not in place now. There is criteria in place not to the hire former employees.

MR. THOMPSON: Is that because of this report?

MR. MAZZA: I would say in part it is a change under the report.

MR. THOMPSON: Top bullet point:

"700 pairs or groups of OPG employees reside at the same address."

That's hiring families as opposed to individuals, I gather; is that going on in the hydroelectric?

MR. MAZZA: I can't speak to that. I don't have specific information on that. I believe it's pretty confidential.

MR. THOMPSON: The last bullet point:

"OPG gives annual incentive plan awards to all non-unionized employees..."

And it goes on to describe some fairly rich awards; does that apply in hydroelectric?

MR. MAZZA: Well, we follow the corporate process for applying incentive awards.

MR. THOMPSON: Over on the next page, there is a bullet point:

"OPG engaged a consultant to conduct a compensation benchmarking study in 2012 which found that base salary, cash compensation, and pension benefits for a significant portion of staff were excessive compared to market data."

Has that consultant's report been filed in this proceeding?

MR. MAZZA: I can't speak to that item either. I believe there is a compensation panel that could address compensation levels.

MR. THOMPSON: All right. Well, can I ask you by way of undertaking to check if it has been filed and, if it hasn't, to produce it before that panel arrives?

MR. SMITH: We will point you in the right direction. It's been filed.

MR. MILLAR: Do we need an undertaking for that?

MR. SMITH: Okay.

MR. MILLAR: J4.6.

UNDERTAKING NO. J4.6: TO CHECK IF THE CONSULTANT'S REPORT HAS BEEN FILED AND, IF IT HASN'T, TO PRODUCE IT BEFORE THAT PANEL ARRIVES.

MS. HARE: And you can respond orally once you have the information.

MR. SMITH: Yes.

MR. THOMPSON: Thank you. Those are my questions, Madam Chair.

MS. HARE: Thank you.

Okay. Next is Mr. Tolmie for the Sustainability Journal.

## Cross-Examination by Mr Tolmie:

MR. TOLMIE: Coming through okay? I have filed a compendium that outlines what I would like to talk about. There has been a lot of discussion today about storage, which --

MS. HARE: Just one second, Mr. Tolmie. We will give this an exhibit number to make sure we have it.

MR. MILLAR: Thank you, Madam Chair. K4.4, and that is the compendium of the Sustainability Journal.

EXHIBIT NO. K4.4: THE COMPENDIUM OF THE SUSTAINABILITY JOURNAL.

MS. HARE: 4.4, thank you. Please continue.

MR. TOLMIE: There has been a lot of talk about storage already today, but what they are referring to is storage of water. You can store it in a pump storage facility, you can use reservoirs with other types of facilities, or you have some stations that are specifically used for peaking applications, so these are all examples of one form of storage, and you can have -- go into considerable detail on how you can optimize that storage process by these incentives that have been discussed at considerable length.

So what I would like to talk about is the question of, why not use direct storage of the output from hydro plants, from nuclear plants, from wind generators, you name it? They all have the same problem.

So I guess the first question is, why have alternative means of storage not been considered by OPG?

MR. MAZZA: Well, I can speak to the mandate that hydroelectric has as part of our shareholder mandate that was referred to earlier, and our mandate really is not to pursue investments in non-hydroelectric, renewable generation projects unless specifically directed by the shareholder.

So our focus has been on, as I mentioned, is looking at pump storage, where we have expertise in it, and we think we can add value to the system.

And as mentioned earlier, we did -- we did supply some information as part of a long-term energy planning process to the Ontario Power Authority on options that we assessed, and that's the extent to -- we have looked at -- as far as additional storage, that's the extent that we have looked at. So beyond that we haven't assessed anything else.

MR. TOLMIE: Storage is, of course, not generation at all, so saying that you are not interested in other means of generation, it's really not relevant to the issue.

MR. MAZZA: Maybe I came across different. It's not that we are not interested in it. There always is an interest in storage, but the specific storage that we focus on based on the expertise we have in our area of the business is pump storage. There is a portion of the company that looks at other opportunities, corporate business development group, and they may or may not be looking at other storage options I am not aware of at the moment.

But to the extent that I can answer the question to you, we have been focusing on pump storage of hydroelectric assets and optimizing our assets in that respect.

MR. TOLMIE: Are you interested in things like profitability for OPG and minimum cost for your customers?

MR. MAZZA: Yes, I am interested in a general way in that.

MR. TOLMIE: So storage does provide greater profits or better service or lower prices for your product? Are these not things that would be important to you?

MR. MAZZA: I can't comment on that. I, you know, haven't done any analysis around that, and whether it does or not, and all we can talk to is the opportunities on pump storage, basically.

MR. TOLMIE: There are examples right around us here of -- there are in fact thousands of examples of systems that use other means of storage. The Enwave system in Toronto that cools all the buildings is a form of storage that conserves electricity on quite a large scale, so there are examples already in use that achieve that objective. Should these not be more seriously considered?

MR. MAZZA: I think in that respect the consideration probably -- we have a group that looks at the system in Ontario and optimizes that system, and I think it's called the Ontario Power Authority, and I think one of their mandates is to look at the overall storage opportunities within the province, of which I have stated they are looking at pump storage. They may be interested in other storage opportunities, so that might be, I guess, a question that they could address better than me.

MS. HARE: Yeah, can I just interrupt here? I have a concern, Mr. Smith. Mr. Mazza said that there may be the business -- the new business development group that may be looking at storage, but he is not aware of that. I understand that. You are responsible for a certain area. But this issue was known to be on the issues list and to be at the oral hearing, so should there not have been a witness here that could speak to whether or not another department was looking at this?

MR. SMITH: We did look at that question, Madam Chair, and I understand it's not Mr. Mazza's responsibility, and I hate to correct my own witness, but we did ask internally whether there are other things that are being looked at by Ontario Power Generation.

MS. HARE: And the answer was no?

MR. SMITH: The answer is no.

MS. HARE: Okay.

MR. SMITH: I do not mean to be at all disrespectful to Mr. Tolmie. It's simply a question of what is and what is not OPG's business as OPG perceives it.

MS. HARE: Okay.

MR. TOLMIE: I am a little puzzled by how it cannot be your business, if in fact there is a way of achieving storage, because you talked a lot about spillage, that there are times when the demand for power isn't there, so you have to let the water run over the dam, effectively, so that's lost revenue, it's lost potential.

MR. MAZZA: All I can speak to, as I have said -- and not to be disrespectful -- we have looked at pump storage, and we have presented these options to the OPA, but -- I don't know if I can reference the long-term energy plan. I think from a pump storage point of view, from a long-term energy planning point of view, the long-term energy plan says that we all in the province -- other utilities, ourselves -- should continue to explore pump storage options, but the cost-effectiveness has to be determined basically in the context of going forward, when I believe the SBG issue we are talking about today will diminish once the turn of -- before the turn of the century comes there will be a decline in SBG --

MR. SMITH: Turn of the decade, I hope.

MR. MAZZA: Turn of the decade, sorry, turn of the decade, sorry. Sorry, not the century; decade. It feels like the decade, but -- feels like the century.

So in the -- like I said, in the context of a long-term view of this, the OPA has basically not accepted any proposals that we thought could be cost-effective for the province.

MR. TOLMIE: At the moment, is the Sir Adam Beck pump storage facility the only major storage facility you have?

MR. MAZZA: Yes. I believe it's the only major storage facility in Canada.

MR. TOLMIE: And that's around -- I think it's 174 megawatts, is it, capacity?

MR. MAZZA: Yes. Per the evidence, it's 174, yes.

MR. TOLMIE: Thank you.

In K4.4, I briefly outlined a simple calculation showing that in the ground under the city of Ottawa, you can store something like 5,000 petajoules of energy, which is many times larger than the total electricity generation in all of Canada.

So would you agree that there is at least the potential there to store energy on a very large scale if we chose to do so?

MR. MAZZA: I think in the overall context there could be potential, but I don't have the expertise to determine whether it is there or not.

MR. TOLMIE: That's simple physics. You take the specific heat times the mass, times the change in temperature; anybody should be able to do that.

MR. MAZZA: True, but I believe somebody would have to do a detailed cost assessment of -- and the relative merits of thermal storage versus other storage, which, again, I believe would be more appropriate for groups that deal with the provincial load and demand in the province.

MR. TOLMIE: Well, we don't seem to be getting even to square one on doing that cost assessment, including the OPA, by the way. I had personally have sent several letters -- many letters, actually -- to the OPA, trying to simply discuss the issue. And I don't get any replies. It's frustrating. Sorry about that.

There is not a simple calculation if you look at the actual production of power from all sources, because the source of information, of this kind of information, just lumps all of the electricity sources together.

But basically every day, the power demand goes through quite a wide swing, and in the night it falls about 3,000 megawatts or so below the mean, and during the daytime it goes above the mean. So we know right off the bat what the potential is. If we could store 3,000 megawatts of power, we can conserve that amount during peak periods. You don't have to do an analysis and detailed study of it.

MR. MAZZA: As I said, there still would have to be some costing and analysis of these alternatives and compared to other alternatives. And I am not in a position to comment on it or even speculate what -- you know, what the real benefits are of the different storage options.

MR. TOLMIE: I am sorry to single you out, because this field is not your responsibility, but unfortunately I do feel that it is the responsibility of the Board and of the OPG to consider all possible ways of achieving any major savings in the operations or improvements.

Let's just quickly look at the four questions that I raised on page 4 of my compendium.

"Could we make the hydro stations more productive?"

So right off the bat, could we do that if, in fact, we had a method of storage -- so forgetting about the cost studies -- could it be done, technically?

MR. MAZZA: Yeah. I realize your question and your focal area is thermal storage. The only comment I made earlier is we have made our hydroelectric stations more productive through efficiency improvements in our mechanical components, turbine runners, and we've added capacity and energy in that respect, to make it more productive and efficient.

And other than that, we didn't see any other opportunity to make it more productive.

MR. TOLMIE: That leads to the second question I raised, then:

"Can the planned OPG capital expenditures be reduced?"

Now, it seems to me that there is a potential, at least, that if you put in storage and the storage isn't too expensive, you would not have to build tens of thousands of megawatts of power to power Ontario. We could use a much smaller amount of power used on a constant basis, put the surplus into storage, take it out of storage when you need it.

And if, in fact, you are also using thermal storage, you are reducing the load because the thing that creates the load for OPG is the -- hot weather in the summertime requires a lot of electricity; cold weather in the winter requires a lot of heating. So if you use a thermal process for your storage, you can kill two birds with one stone. You can reduce the demand, and you can increase the production.

MR. MAZZA: I agree with what you are saying. However, we haven't -- like I mentioned before, we haven't done any studies in the area, and our focus really is, you know, maintaining and operating our assets that we have, that we have been told by our shareholders to maintain in a cost-efficient and cost-effective manner. And that's been our focus, and that's all I can really comment on, if you will.

MR. TOLMIE: My third question deals with exactly that. If you use storage of any sort that's located at the consumer end of the channel, instead -- you are concerned, of course, with the supply end, but at the consumer end, the consumer can also store energy. And in any -- in both forms, in both thermal form and electricity form, and that would make the system much more reliable, because if there is a breakdown in the grid, breakdown in the transmission lines -- you name it -- because the energy is stored at the bottom end of the chain, the system is inherently more reliable; would you agree?

MR. MAZZA: Yeah, I agree that the system could be more reliable but again, within the context of what I deal with, I can't really comment on that. I think there is experts in the industry, like the Independent Electricity System Operator and the OPA, that could probably comment on improved system reliability from your proposal. That is really all I can comment on.

MR. TOLMIE: Okay. Can I go on to the No. 4 question, then? At the present time, the variations in demand are, to a considerable extent, met by natural gas generators. If you used storage of some sort, electricity storage, I would suggest those natural gas generators are not needed at all. And that means that our GHG emissions, which are, in fact, over 100 million tonnes per year -- not 1 million tonnes, as the OPA says -- we could eliminate those. Would that not be a useful thing?

MR. WILBUR: I would agree that the expanded storage could result in less gas generation and -- resulting in less emissions. I am not sure about eliminating them completely, but certainly less.

MR. TOLMIE: I am a physicist. I look at these things in very simplistic terms, of course. So from a calculation point of view, the energy is there, the capacity to store the energy is there, the means of achieving that objective is there. All we lack is the will, apparently, in my simplistic view of the world.

Sorry, I am getting into lecturing now, which is really not what I am here for.

One of the problems for the Ontario power industry is that the most attractive means of generating power, nuclear or dams for hydro facilities, are expensive. They can't be carried out on a small scale. They take many years, and more commonly, decades to build. They require complicated environmental studies to see if they should be built in the first place.

Storage is something you can put in in a matter of weeks. And I think if you looked at the price, you would find that it is, in fact, competitive with those other alternatives. So -- and it also -- in the case of hydro facilities, for example, I live in Ottawa. We have lost two of our biggest tourist attractions, Chat's Falls and the Rideau -– and, sorry, the Chaudière Falls at one time were the biggest attraction for tourists in Ottawa, and effectively both have been almost obliterated by dams, so there are big negatives to building these facilities, and I think we should be careful to limit that kind of damage to what is essential. Would you agree with that?

MR. MAZZA: Again, I can't comment on new generation from what you are saying. All I can say is that if we were to build new facilities there is a process that hydroelectric utilities such as ourself go through, environmental assessment process and stakeholdering process, to build them, and your considerations would be taken into account.

But a lot of these facilities were built post-turn-of-the-century and are over 80 years old. Yeah, there may have been some tourist attraction. I am not disagreeing with you. But they are part of the system now and our responsibility is to maintain them.

MR. TOLMIE: Do you think it would be fair to say that the objective of the planning process is to ensure that the production of power always meets the peak demand for power?

MR. MAZZA: I think that question, again, if you've contacted the OPA, is better addressed by the OPA -- sorry, Ontario Power Authority. Using acronyms.

MR. TOLMIE: I am a little confused now. Does OPG not concern itself with how to make its own bottom line as healthy as possible and how to make its energy as cheap as possible? What does OPA have to do with that?

MR. MAZZA: Yes, we are concerned with that, and we are doing our best efforts to do it with the facilities that we have that are part of this hearing. That's our main -- our main mandate, to make the existing facilities we have productive, efficient, and effective, basically, and make sure that we continue to invest in the existing renewable resource.

MR. TOLMIE: Do you reject the idea then that there might be better ways to do the job?

MR. MAZZA: I am sure over time new technologies will come about that could displace certain technologies.

MR. TOLMIE: The alternative technologies that I have been talking about have been in use for generations. They are not new. When will we start seeing these studies?

MR. SOHI: The technologies, obviously, you know, it may be feasible, but we have not done any studies in the regard -- you know, in terms of technical feasibility or economic feasibility. As OPG, we have not done any of that work, and we don't have any data to support whether it's viable or not. And definitely it's not in our rate application either.

MR. TOLMIE: I would have to agree with that last point. There was nothing at all about storage, apart from pump storage, in the application, so there was nothing in the application to take shots at. It is effectively a blank screen.

MR. SOHI: The rate application is based on the exhibit, as Mr. Mazza pointed out earlier, Exhibit A1-4-1 on page 2, which really talks about what OPG's mandate is. The whole application is based on that, so that's why we don't have any data, in terms of the feasibility studies or, you know, economic feasibility or technical feasibility studies. We have not done that type of work, largely because of what our mandate has been. Not to say, you know, we wouldn't explore that, but definitely we have not done any work on that area.

MR. TOLMIE: I did some work of my own on the area over the weekend. I had to stay up all night two nights to do this, but I simply recorded the IESO record of production of electricity that they record on an hourly basis, and you can clearly see just in a weekend of looking at those numbers that the production from our nuclear plants fell by about 1,800 megawatts when the demand was low, so in fact, they are putting on the brakes on the nuclear stations, and by about -- and I think it was 1,400 megawatts for the hydro stations.

So again, when there is no demand there and you have no choice, of course, but to throttle the production -- but if in fact you were using storage, you would then have not only that 1,400 -- 3,400, it was, for nuclear, Ontario was also exporting an average of around 2,000 megawatts during that period just to get rid of it, so we ended up with something like 5,300 megawatts of power, just from, as you can see, as being lost to the system because of lack of adequate storage facilities.

MS. HARE: Is there a question there, Mr. Tolmie?

MR. TOLMIE: Yes, well, the question is, why isn't anyone looking at these things?

MR. WILBUR: I guess I would say that if we were to build more storage to address this problem it's going to take years to build that, to put that storage in place, and according to our own forecast, we don't anticipate the significant level of surplus situation that we are seeing this year and next. We don't anticipate that going forward beyond about 2020, as Mr. Mazza mentioned earlier. And if we were to build a new storage facility, it's unlikely it would be in service by 2020.

MR. TOLMIE: Have you discussed that with people that are familiar with the technology?

MR. WILBUR: Not to my knowledge.

MR. TOLMIE: I would suggest you do that, but that's your business, of course.

On the issue of profitability, one of the other things I noticed from my own little study was that Ontario was visibly exporting 2-, 3,000 megawatts of power at times when the price of power was minus 10 cents. In other words, you are not only giving it away, you are paying people to take it away from us. And there were other times when the price of power shot up, and it shot up to 10 cents, positive 10 cents.

The amount of storage that you would need to handle those spikes upwards or downwards would be really quite small. Have you considered the potential of building small storage systems to deal with that specific problem?

MR. MAZZA: No.

MR. TOLMIE: Do you agree there is a potential there to fix the problem that way?

MR. MAZZA: There may be a potential, but it's speculative, and whether -- whether we can fix it that way.

MR. TOLMIE: Would you be willing to discuss that with people that have studied this issue?

MR. MAZZA: As I stated, we -- like, personally, I don't know if our panel would be, you know, the proper panel to -- or the proper group to be looking at this or even discussing it, but...

MR. SMITH: I can certainly say on behalf of the company if the Board were to direct us to look at storage then OPG would do that. I mean, obviously, of course, subject to the act, which deals with payment amounts for prescribed facilities; but we would look at it, if that is what the Board wanted us to do.

MS. HARE: Okay. Thank you.

MR. TOLMIE: I don't think I should be haranguing the witnesses like I am, but I am trying to raise a problem, and I think it's a serious problem.

MS. HARE: Well, I think that's clear, but I also think the witnesses have said this is not their area of responsibility and they haven't looked at it --

MR. TOLMIE: But it is --

MS. HARE: -- so what Mr. Smith has said is that if the Board in the decision -- if the Board says lookk at it, they will look at it, and so you have raised a new issue that they haven't looked at, so I am not sure that this panel can actually go much further.

MR. TOLMIE: The panel is, of course, looking at the payment price of power, and it seems to me this is a very significant consideration in determining that price. So I think I will leave it at that.

MS. HARE: And you will make that point when you put in your final submissions?

MS. TOLMOIE: Mm-hmm.

MS. HARE: Thank you.

MR. TOLMIE: Thank you.

MS. HARE: We will take a short break now until 25 to four. When we come back, the Panel has a few questions. This Panel has a few questions of the witness panel.

And then I did say yesterday that we would like to hear oral submissions, if there are any, on the confidential treatment of the KPMG report. Okay?

Thank you.

MR. SMITH: Thank you.

MS. HARE: So we will be back at 25 to four.

### --- Recess taken at 3:19 p.m.

### --- On resuming at 3:38 p.m.

MS. HARE: Please be seated.

The Panel has a few questions. Board member Duff, would you like to go first?

# Questions by the Board:

MS. DUFF: Sure. I have a few questions just in considering Mr. Tolmie's cross-examination regarding -- we just spent hours talking about surplus base load generation, the need for spill, just because the demand right now at that time of the day, month, year, it's surplus, and that spill, as Mr. Thompson said, is waste, and part of the storage that you have in your hydroelectric assets is that you are storing the water so that when you generate you are generating at the peak time so that you can feed into the IESO credit; is that correct?

MR. WILBUR: Yes, that is correct.

MS. DUFF: I think -- could I say or could someone suggest that if you could run your base load generation, your hydroelectric assets, 24 hours a day, fully utilized, but you don't feed into the IESO grid, you actually store it first, is that -- and you are holding it in that storage facility, then feeding it into the IESO when needed in peak -- is that something, that idea -- that's a different type of storage, which would still be, I am suggesting to you, within the hydroelectric, you know, realm of part of your business, and you can...

MR. WILBUR: Well, if we could do that, that would obviously -- that would help. That would eliminate the waste.

MS. DUFF: It would eliminate the need for the surplus base load generation variance account.

MR. WILBUR: If it eliminated the waste there would be no account, yes.

MS. DUFF: And it would also eliminate the need for the incentive mechanism.

MR. WILBUR: No, I wouldn't agree with that --

MS. DUFF: Well, actually, would it change -- sorry for interrupting. Would it change the hourly Ontario energy price?

MR. WILBUR: Would it change the Ontario hourly energy price? I guess it would. There would effectively be -- if we could -- I think what you are suggesting, if we didn't have to -- if there was no surplus base load generation and we didn't have to spill water at certain times, then that means that water would be available or the energy produced by that water would be available to be used at other times, when it is needed. That is the idea of the storage. So that would change the price as well.

But that would be -- that would be time-shifting. It just -- we wouldn't be using water, we would be using this other electricity storage method to time-shift, so that would be -- it wouldn't change the need for an incentive mechanism.

MS. DUFF: Okay. Thank you. That's fine.

I had a few questions regarding benchmarking, and I am referring to Board Staff's compendium K3.7. And Mr. Mazza, we were just talking about the numbers when you are comparing yourselves to other utilities, and in terms of your responsibility of costs that you can control, when we are looking at the Board Staff compendium number 2, just to point to something, there is the -- in table 1 there is the base OM&A costs -- this is of previously regulated assets

-- there is the project.

Now, would those be -- those are the two lines which you say are under your --

MR. MAZZA: That's under our direct control in hydroelectric.

MS. DUFF: Thank you for helping me out there.

So those are the direct ones. And to the extent that you are using these benchmarking studies, are they covered on these two lines in terms of the costs?

MR. MAZZA: Yes.

MS. DUFF: Do you feel you have comparatives with other utilities in North America that allowed you to look at the cost for base and project and how you can compare yourselves?

MR. MAZZA: Yeah, as stated for base we have the two benchmarking studies --

MS. DUFF: Yes.

MS. DUFF: -- which are the EUCG and Navigant. On the project side they are included in the EUCG study, and there is a lot of effort by all the different utilities to ensure there is an apple-to-apple comparison of costs.

So when it comes to labour rates it's got to be an apples-to-apples comparison, because, as you can see, there are different elements of labour rates and how companies treat them. When it comes to maintenance, some companies segregate the maintenance in a different fashion, so there is a lot of effort done there to make sure we have that apples-to-apples comparison, and in fact, it's difficult to do, but I think we have done a fairly good job over time to improve that. And I can personally say I have gone to a lot of these sessions, and I started working with them, and I believe that we have a very good comparison with the other utilities.

MS. DUFF: When we go further down this the table into lines 4, 5, and 6, this is where, from what I understand, there are costs which are allocated to the previously regulated hydroelectric business.

MR. MAZZA: Yes.

MS. DUFF: But they are not part of the benchmarking studies. This is where the apples to apples just doesn't work.

MR. MAZZA: Well, that's true, because each company is organized differently. So some companies may have some functions within the business, some companies may not. So when it comes to IT costs, some companies treat IT within the business, some are funding it through the corporate level, so again, through the process, each company makes sure that the correct bucket or similar buckets are included in the benchmarking. I don't know if I am explaining it properly --

MS. DUFF: Oh, no, I understand. And just when I look at the total OM&A, though, the first two lines in 2014 plan is 88.1, and -- but when -- the total OM&A, once I do include those fully allocated costs, the costs to -- somebody has determined are driven by the previously regulated hydroelectric assets -- it's 145.

So that delta, the ones which are -- you can compare yourselves to other companies versus the 145, because that 145 is what has to be recovered, and it is, would you agree with me, it is associated with the previously regulated hydro assets?

MR. MAZZA: Yeah, I agree that they are indirectly associated. However, we can't do the full benchmarking comparison. That is all I am saying, because other utilities cannot get that information as well or --

MS. DUFF: Yeah, and are --

MR. MAZZA: -- but I do agree that those are the costs that we want to recover.

MS. DUFF: I am just thinking from this panel's perspective on the Board --

MR. MAZZA: Yeah. Yeah.

MS. DUFF: -- I mean, that is really what we are looking at. That amount has to be recovered, you know, and I am interested, how could we compare that with other utilities. And in terms of your responsibility, like, with your incentives and your compensation, does your responsibility end at the 88.1 with the subtotal of operations, or does it include those allocated costs?

MR. MAZZA: My responsibility ends with the base and project OM&A, and to the extent that I can -- like, there are, as you will probably see or have seen, there are other benchmarking studies that our IT folks do, our human-resources folks, so that is where you could get a gauge on whether those areas of the company are also benchmarking with other utilities and what they are doing.

So if everybody is benchmarking within this reasonable level, if you will, Q1, Q2, the expectation is that the 145 is a reasonable number, in my view.

MS. DUFF: So the Board needs to look at an assortment of benchmarking studies of different aspects of your business rather than the business line itself, rather than taking a perspective of, this is nuclear, this hydroelectric previous, this is newly regulated, we are looking at project versus base versus IT versus HR. That is what we need to look at in order to get that comfort level?

MR. MAZZA: Yeah, I guess the whole would be the sum of the parts, I would say, because if each part is benchmarks reasonably -- in other words, if IT costs benchmark reasonably and they are supporting us, they are allocating costs to us, then I would say indirectly then we would likely be benchmarking -- well, that piece would help in our benchmarking, if you will, if it's top quartile.

MS. DUFF: Because at the end of the day, I mean, we are setting a price for the hydroelectric assets. We are setting what the -- well, it's not the rate, it's the payment amount, and it's separate, so we are actually -- the way the Board is giving its decision, it is based on the business line. So I just -- I am just proposing to you, with your experience in dealing with these other North American utilities, is that something that you are talking about? Maybe, is it a customized benchmarking study, is it one that goes to looking at your unique corporate structure and what is allocated and then trying to find utilities that fit?

I realize that would be a difficult exercise, but please inform me of the conversations that you are having and what is happening in other jurisdictions.

MR. MAZZA: Well, this has been discussed at the EUCG level, and again, there has to be a consensus amongst the utilities of what level of benchmarking they can do, from the hydroelectric perspective. Nuclear does their own.

And the view was to really -- to really do the can -- it's called hydroelectric benchmarking, so what you are trying to do is determine whether you have got the right processes in place, the right maintenance practices, operating practices that make you efficient and effective and prudent in maintaining your activities.

So that really is what those benchmarking groups are interested in. They are not interested in corporate activities that may be going on that other companies may or may not have.

So some companies are smaller. Some are just a single -- a single-station utility, if you will. They own one station.

Some are like the Tennessee Valley Authority; they are similar to us in a way. They have nuclear, hydro and thermal, so they are more similar to us so it's easier to do a comparison. Similar in the way that they are large and they own, I guess, facilities in all three nuclear production -- sorry, production businesses. However, they are structured differently, and that is where the challenge is.

MS. DUFF: I would think it would have to be quite a customized benchmarking study?

MR. MAZZA: Yes. It would require pretty significant customized benchmarking studies that we would have to undertake. I am sure it could be done. I mean, it can be done, but --

MS. DUFF: Are you able to provide me with the cost to OPG of participating in the EUCG and the Navigant study? If that's in the evidence, can you just point it --

MR. MAZZA: It's not in the evidence.

MS. DUFF: What annual cost are we looking at, in order to participate in those studies?

MR. MAZZA: For the existing studies that we are partaking in?

MS. DUFF: Yes.

MR. MAZZA: For the existing studies, Navigant –- and I am talking general terms, because we are negotiating with them this year, but for the six regulated facilities that we have been benchmarking for years with Navigant, it's about 6- or $7,000 a station. Okay? Per year.

So as I said, to do all 54 stations would be quite expensive.

So with EUCG it a different type of benchmarking. There's a lot of effort by each company to collect the data and vet it and so on, so the cost to benchmark those is more in the order of 5- to 10,000 for a larger fleet of facilities.

MS. DUFF: $10,000?

MR. MAZZA: Yes, $10,000. So that's all it is costing for the EUCG benchmarking, but there is a lot of effort –- that's the cost to supply the data, vet the data with the EUCG, but there a lot of effort in the company to collect the data.

MS. DUFF: That's actually -- if we could move on to a different aspect of my questioning, it's just: What is the value of the benchmarking studies that you are doing today?

I was looking at your -- I was -- I am able to look at the cross-examination, and you have used words like how "significant" it is for you -- you drew a reference to the -- one time you made adjustment to the company in 1990 as a result of this benchmarking.

Are you able to provide me with an example, like in 2012, 2013, where you have made a change or reviewed your budget and then made an adjustment as a result of the benchmarking analysis?

MR. MAZZA: Lately there aren't any, because we were focussing -- lately we haven't made any changes, but I do refer in the evidence, in our benchmarking section, of areas that we did look at with other utilities and we took some action.

And one of them is a simple topic of overtime. I know it's been an issue with the Board. And at one point in time in the 1990s, we had about a 10 percent overtime rate. And now it's gone down to 5. And we use overtime more strategically, and make sure there is a business case for it, whereas in the past maybe it may have been more ad hoc. I can't speak to it, but --

So that's where we sort of gained some experience from other utilities on how they do it, and how -- what they actually considered to be valuable from an overtime perspective.

And so that that is one example where we have used it. But it's more of a historical thing, going back ten years.

MS. DUFF: And again, referring to Board Staff's compendium -- and I am on page 6, so this is K3.7 -- we had a discussion about who is in the first quartile, the second and the fourth, those -- the stations that are in the first quartile -- sorry, you have got it now?

MR. MAZZA: Yes.

MS. DUFF: The stations that are in the first quartile again, that is ending at the base OM&A and project OM&A level?

MR. MAZZA: For EUCG, it includes projects. For the Electricity Utility Cost Group, they do include projects in there.

MS. DUFF: But it does not include the additional -- the other costs that are allocated?

MR. MAZZA: Correct.

MS. DUFF: And really there is no evidence on where OPG stands in terms of those facilities, in terms of its benchmarking on a fully allocated cost? I think that --

MR. MAZZA: Yeah, again, I would just like to stress that we are comparing apples to apples with other utilities.

MS. DUFF: Yes.

MR. MAZZA: When they are doing the benchmarking, they are not including those costs either. And we are not, so...

MS. DUFF: But it ends there?

MR. MAZZA: It ends there. And as I mentioned, there are exceptions with Navigant, with some IT costs that are direct, like workstations. If you can assign something directly and all the utilities have that data, then they will put it in.

I mean, that's the extent of the corporate piece, if you will.

But if you look at the line items in the evidence there, it's project OM&A and base OM&A; that's the majority of the cost pool.

MS. DUFF: Thank you. Just one final area I wanted to talk to you about. And I think it was -- maybe it was yesterday, talking about the hydro assets and that the market price has been low, and, in fact, with respect to the non-regulated assets, the ones that are newly regulated in 2014, as proposed, that the market price has been lower than, actually, your operating costs. And that's been the case since 2005.

I mean, I don't need a particular date, but do you remember that conversation?

MR. MAZZA: Yes, I do remember the conversation.

MS. DUFF: In your capacity as vice president in hydro, during those years from 2005 to 2013, the fact that those assets were not making any money at the margin, did it affect any of your decisions of capital expenditures, OM&A? I just wanted to explore a little bit further with you.

Did you have certain financial pressures that you felt and which constrained your ability to make decisions?

MR. MAZZA: Well, there were financial pressures from a revenue standpoint, but these assets still are very important to the system. So to the extent that we want to keep them, if you will, as part of the system, and the incremental costs associated with them are reasonable, we will keep prudently spending money.

Some of these assets may have cost more and did cost more than the market price, but what has to be recognized is that if we didn't operate the assets, we still have responsibilities to operate each one of these anyway, whether we're producing -- we have dams on site; we still have water management responsibility. We have all these costs that we wouldn't be able to basically shed or shut down the facilities.

In other words, we do -- we do take cognizance of the fact that the market price is low and they are not making as much, and that is where we look at our -- if you see the way we set up our portfolio, we've set it up such that the assets that are more value to the company and are required for reliability, more reliability, are pumping, we tend to focus more and make sure that those assets continue to retain their value.

The assets that, in this case, may not be as valuable, yeah, we do look at reprioritizing our investment plans, as long as they are kept safe and environmentally sustainable.

MS. DUFF: Because I think you referred to it during your portfolio reviews as a potential or --

MR. MAZZA: Yes.

MS. DUFF: -- or proposed projects that the newly regulated and the previously regulated were grouped together in the past.

MR. MAZZA: Yeah, we treat the hydroelectric assets as big -- as a big -- it's part of the portfolio approach, we treat the assets as -- individual stations as part of our portfolio, and we make investments based on what asset class within that portfolio, I guess, if you will, they are part of.

So the bigger assets like the Sir Adam Becks, the Saunders, the Shipshaw (ph) -- which is another station that now is newly regulated -- these are some of our high-value assets. They produce good value for the ratepayer. We want to ensure that they continue to do, and we treat them -- we call them flagship assets, and we continue to the treat them that way.

There are assets that are not as important to the system or not high-capacity factor assets that are not peaking, of course. In those assets we tend to invest less, and that applies to our smaller facilities. We have actually, you know -- take a different approach in how we invest in those, and we have different targets as well.

MS. DUFF: And will that change with the regulation of those assets?

MR. MAZZA: I believe that it won't, because we have been using a similar approach. We are going to keep that approach. I...

MS. DUFF: Because the value assessment on how you prioritize is not based on the revenue that's being --

MR. MAZZA: Well, we would have to assess how that would change, but we still have commitments on all those assets, if you will, from a regulatory point of view. So what we would change possibly is we could be looking at in the long-term future when it comes to long-term sustainability making some more investments where they are prudent to make, but in the short-term I don't see any changes.

MS. DUFF: Just one area I wanted to clear up. It was a cross-examination with Mr. Thompson, and he was talking about the current variance accounts, the balances as at December 31st, 2013. I guess they were 2011, '12, and '13, so the hydro incentive mechanism variance account and the surplus base load generation variance account, the first one, in particular, I guess. This question will be to you, Mr. Wilbur.

The balances that OPG has proposed for disposition in this proceeding, is there some double-dipping in the numbers? I just wanted to -- there was a conversation that went on about on a -- going forward, how you were going to correct for that, but these balances are these balances. Are there any adjustments that should be made to these balances as at December 31st, 2013?

MR. WILBUR: We are not proposing to make any changes to those balances, as we feel that what we have done is followed the order that we got at the last hearing. And what we are proposing to do going forward with this new evidence we have here is to -- that there won't be any double-dipping.

MS. DUFF: And I don't like the words "double-dipping", so the point is that the average as it was determined -- there were reasons why you have spill that are not related to the market price, and it's that spill which decreases the overall average production; is that right?

MR. WILBUR: No, it's not, no, it's -- the spill associated with the surplus base load generation is what decreases the average. It's not the spill associated with the other reasons.

MS. DUFF: The other reasons being -- I think you talked about it in the technical conference --

MR. WILBUR: Well, some of the --

MS. DUFF: -- but just for ease --

MR. WILBUR: The main one really being insufficient capacity at the plant for the inflow, either due to outages at the plant or really high inflows.

MS. DUFF: For the record, is it that you -- I understand you were following the Board's directions, but with hindsight being 20/20, is there -- are there -- is there -- possible that you could make those calculations, just -- do you have the data available? Do you know the assumptions that would be made and apply that?

MR. WILBUR: I believe we do, yes.

MS. DUFF: I am not asking for them right now. I am just thinking about -- and I wanted to hear your answer.

MR. WILBUR: Yes, we have that. We have --

MS. DUFF: Right. And from 2011, '12, and '13?

MR. WILBUR: For the currently regulated facilities for those years, yes, we have that data.

MS. DUFF: Those are my questions.

MS. HARE: Actually, I was just wanting to -- sorry, Mr. Smith.

MR. SMITH: This is going to come up again at the deferral and variance account panel stage, because we are proposing to clear the surplus base load generation variance account. Always dangerous to do that, but I was going to volunteer the undertaking to do the calculation rather than wait for it to come up again at the deferral and variance account panel, where it will be Mr. Kaiser's responsibility and not mine, but being the generous guy I am, I thought I would do it now. I mean --

MS. HARE: No, I think that's a very good idea. So Mr. Millar, could you give us an undertaking number?

MR. MILLAR: J4.7.

UNDERTAKING NO. J4.7: TO PROVIDE THE CALCULATIONS FOR 2011, '12, AND '13 FOR THE CURRENTLY REGULATED FACILITIES FOR THOSE YEARS.

MR. SMITH: It will be a matter of argument, because it's not included because of the terms of the Board's order establishing the deferral account, but I certainly understand that people may have a difference of opinion with respect to that.

MS. HARE: Okay. Thank you. I wanted to follow up on the benchmarking, but Ms. Duff actually asked most of the questions, so I will say something and ask you to respond.

It occurred to me, listening to the benchmarking, that the benchmarking is really not that worthwhile, given that so many important costs are not included. For example, you have indicated that 18 percent of the total is not included because those are centrally held costs, and so those aren't comparable to other utilities.

And then in discussion with Mr. Rubenstein he said he understood why regulatory fees and costs and environmental costs are not included. I actually didn't understand why they wouldn't be. But the more you exclude, the more I think the benchmarking results aren't comparable. So I would like to ask you to comment on that.

MR. MAZZA: Well, I believe from running a hydroelectric business point of view and operations and maintenance point of view and to some extent the administration and the field and within our business, I think they are useful, because we are comparing -- we still are doing apples-to-apples comparison with these other hydroelectric utilities --

MS. HARE: But how is it apples to apples when you are taking out a whole bunch of costs?

MR. MAZZA: Well, but they are not including them as well.

MS. HARE: No, I know, but maybe those are like 2 percent and yours are 18 percent.

MR. MAZZA: That we can't comment on, but we think it is useful. We have -- one of the merits of it is, like I said, is to try and determine best practices. So it's not only about numbers, but it's also sitting down with different utilities and determining best practices that will drive you to reduce or improve your cost structure, whether it's related to operations, whether it's related to maintenance practices, whether it is -- you know, how we operate our sluiceways and what kind of investments we make in them.

So from the specific hydroelectric point of view, if you are running specifically a hydroelectric business, I think at the end of the day it will drive you to make some improvements, and I have listed here some of the ones that we actually did make as a result of benchmarking.

MS. HARE: You know what? I actually have no problem with that. You are learning from that. I guess my problem is in saying which quartile you are in in comparison, because I don't -- I am questioning the value of the comparison when so many costs are excluded. That really was the basis of my question.

MR. MAZZA: Yeah, I am having trouble understanding -- all I am saying is when you compare each one of these -- each one of our facilities individually with other facilities in the pool of the 301 plants that we benchmark in the electricity utility cost group, I mean, the focal area is on operations, maintenance, and administration of the plant. That is the focal area.

So when you are looking at these facilities, I believe that it will guide you to make some improvements in the direct costs associated with these facilities.

I agree that there might be some external costs to hydroelectric specifically that it won't inform me on, but I believe as -- in running a hydroelectric business, which we are running as part of the mandate of our company, I think it is useful, and we have done a cost/benefit analysis of Navigant and EUCG, whether we should continue or not continue, and we thought it was still prudent to at least continue, you know, spending around 70- to $80,000 a year on the benchmarking. If we get direction that we shouldn't be doing it, then that's different, but I believe personally that it is useful.

I guess Mr. Robby pointed out that we have in our evidence that in the past -- and again, I guess it's an older improvement, but when we were doing benchmarking we did have more operating centres in the business, and back in the late 1990s we made investments in some of our operating centres, and we made improvements whereby we reduced operating centres from about 18 to six that we have now, and that in effect drives down your operations costs, the number of operators you need, and so on.

So we have over time made improvements. Now, when you get to the end of the curve I guess the level of improvement you can make I would say is harder to achieve. You are getting to diminishing returns, if you will.

So my personal view sitting here in front of this panel is that I think it is useful.

MS. HARE: Thank you. Those are -- oh, Mr. Smith, do you have redirect?

MR. SMITH: I have run out of undertakings to volunteer. Just one moment.

No re-examination.

MS. HARE: Thank you. The panel is excused with the Board's thanks.

# Procedural Matters:

We have two matters. One is whether or not there are any oral submissions on the KPMG report with respect to the proposed redactions. Mr. Rubenstein, you look keen to go. Now, Mr. Smith, do you actually want to go first?

MR. SMITH: No, I have no submissions beyond the --

MS. HARE: What you are already said?

MR. SMITH: Yes.

MS. HARE: Good. Thank you.

So, Mr. Rubenstein?

# Submissions by Mr. Rubenstein:

MR. RUBENSTEIN: I will just be very brief. Does the Panel have the OPG justifications sheet?

MS. DUFF: Yes.

MS. HARE: We do now.

MR. SMITH: That perhaps should be given an exhibit number.

MR. MILLAR: K4.5.

EXHIBIT NO. K4.5: OPG JUSTIFICATIONS SHEET.

MR. RUBENSTEIN: I will just be brief with respect to our submissions on this.

With respect to first two categories of information -- impact on labour relations and commercially sensitive and labour relations -- SEC doesn't object insofar as OPG is able to confirm that the information that they have redacted from the KPMG report, or they are seeking to redact because of labour relations issues, is with respect to initiatives that have not yet occurred. I only -- I raise this just because the report is from 2012. It's not clear -- it's not exactly clear.

With respect to the third category, commercially sensitive supply information, with respect to all the pages except page 68, we -- SEC doesn't see a reason for why they should be redacted. It's simply -- or at least how we read the information, simply aggregate information, not individual areas of cost reductions or supply chains. Nor does it set out, really in any detail, what the methods that it is seeking to propose to do so.

With respect to page 68, which OPG does mention specifically, I won't go through it. I will leave that to the Board to do, but I will just say it's not clear to SEC if even that information deserves confidentiality treatment. It's not clear from the specific rationale for the various areas that they are seeking to reduce if that provides, really, any commercial advantage to other parties, based on the brief comments in that chart, as well as the numbers seem to be based on past years.

So I would just make those statements. And just further, as similar to the comments on the first two pages, if some of those opportunities have already occurred or they have already done some of those initiatives, again, it would not seem to us to be a reason to redact that information.

MS. HARE: Okay. Thank you.

Mr. Thompson, do you have submissions now? Anyone else? No?

Mr. Smith, do you have any reply? In particular to answer the question that Mr. Rubenstein had as to whether or not those were past numbers.

# Submissions by Mr. Smith:

MR. SMITH: No, they are forward-looking.

MS. HARE: They are forward-looking?

MR. SMITH: In both respects, both with respect to the items in labour relations and the other matters beginning at page 68.

Other than that, we -- I stand by the justification and have nothing further to add.

MS. HARE: Okay. Thank you.

The other matter I wanted to raise was a date for the technical conference. Again, assuming that you file the update on the Darlington refurbishment project on July 2nd, we had proposed a few dates that we thought would work.

Has there been any discussion amongst parties as to when?

MR. SMITH: I am afraid we haven't had an opportunity to speak to our friends. We are available any of the days that -- I believe it was 8th, 9th, 10th, in that area. OPG is available on any of those days, and we'll have --

MS. HARE: What we would like to know, then, is which are the dates -- we should probably pick two dates -- and then whether or not it is realistic to think that we will start the hearing, then, on the Monday, which would be

MR. SMITH: The 14th, I believe.

MS. HARE: The 14th? Okay.

MR. SMITH: I believe that was the date. Yes.

MS. HARE: So we can pick that up in the next few days. Okay. Thank you very much. Thank you, panel.

MR. SMITH: Thank you. I should advise Mr. Kaiser will be here tomorrow.

MS. HARE: Thank you.

### --- Whereupon the hearing adjourned at 4:13 p.m.