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THE ONTARIO ENERGY BOARD

RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY

STAKEHOLDER CONFERENCE

Held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, January 10, 2013,
commencing at 9:30 a.m.

A P P E A R A N C E S

ROSEMARIE LECLAIR	Board Chair and CEO
CYNTHIA CHAPLIN	Vice-Chair and Member
MARIKA HARE	Member
PAULA CONBOY	Member
CHRISTINE LONG	Member
EMAD ELSAYED	Member
PETER FRASER	Board Staff
BRIAN HEWSON	
LISA BRICKENDEN	
LAURIE KLEIN	
DUNCAN SKINNER	
EJIRO WINTHORPE	

PRESENTERS:

BRIAN HEWSON	Ontario Energy Board
LISA BRICKENDEN	
LARRY KAUFMANN	Pacific Economics Group (PEG)

ALSO PRESENT:

JULIE GIRVAN	Consumers Council of Canada
MAURICE TUCCI	Electricity Distributors
ADONIS YATCHEW	Association (EDA)
GIA DeJULIO	Enersource Hydro
ANDREW SASSO	EnWin Utilities
INDY BUTANY-DeSOUSA	Horizon Utilities
CARM ALTOMARE	Hydro One Networks Inc. (HONI)
ALLAN COWAN	

A P P E A R A N C E S

PATRICK HOEY JANE SCOTT	Hydro Ottawa
MARGARET NANNINGA	Kitchener-Wilmot Hydro
JUDY SIMON	Low Income Energy Network (LIEN)
RICHARD STEPHENSON JUDY KWIK	Power Workers' Union
ELENA YAMPOLSKY	Powerstream Inc.
JAY SHEPHERD	School Energy Coalition (SEC)
COLIN McLORG ALEX BAKULEV	Toronto Hydro-Electric System Ltd. (THESL)
JEFF GUILBEAULT	Peterborough Distribution
LORI McLORG	Veridian Connections
BILL HARPER	Vulnerable Energy Consumers' Coalition

I N D E X O F P R O C E E D I N G S

E X H I B I T S

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NO EXHIBITS WERE FILED IN THIS PROCEEDING

U N D E R T A K I N G S

Description	Page No.

NO UNDERTAKINGS WERE FILED IN THIS PROCEEDING

Thursday, January 10, 2013

--- On commencing at 9:30 a.m.

MS. BRICKENDEN: Good morning, everyone. I would like to make a brief announcement before we commence. Unfortunately our remote participation technology has a bit a hiccup and we are currently setting up a new feed for those of you who -- they won't be hearing me, actually, so I feel a little silly saying this, but to the people in the room, we are e-mailing new instructions for people who wish to participate remotely, and also individuals that are out there - I see now we are on air - please contact our IT help group and they will send you the new instructions on how to log in, okay? Thank you.

I'd like to pass the mic over to Peter Fraser.

OPENING REMARKS BY PETER FRASER:

MR. FRASER: Well, good morning, everybody, and welcome to this stakeholder meeting addressing performance measures and benchmarking. My name is Peter Fraser. I'm the managing director of regulatory policy here at the OEB, and I would like to start off with a few introductions.

To my left is Brian Hewson, who is the lead on the renewable regulatory framework for electricity project here at the Board, and to his left Duncan Skinner, who many of you may well know is a longstanding expert within the Board on these issues of the performance measures and data that we've been collecting over the years. Lisa Brickenden, I'm sure many of you are aware, who spoke to you initially, Lisa is our lead on the performance measures project.

She's being assisted by Laurie Klein, who is sitting on the right here.

To my immediate right is Larry Kaufmann, who is a consultant and is a renowned international expert in this field, and Ejiro Winthorpe. Ejiro is the person who is going to have to be handling all this data trying to turn it into something sensible and put together a scorecard that we are all going to be able to use. So he has actually the toughest job of all and I guess a big interest in making sure we get this right.

The session today is a stakeholder meeting, meaning it is not a hearing, but an informal session convened by the Staff. We have with us today a number of Board members, from Rosemarie Leclair, our chair; Marika Hare, Christine Long, Emad Elsayed, Paula Conboy. Am I missing anyone there? So that's five. That's five so far.

Board members will be here and many will be -- well, I don't know who will be dropping in and out during the session, but the focus on the session I would say is really as an opportunity for everybody in this room, and, hopefully, when we get them hooked up, to people remotely, as well, to exchange views on this important topic. It is an opportunity for us to listen.

And I would say is particularly a great opportunity for those who participate today, because we have with us or we will have remotely the members of the working group, which are having their initial measuring performance -- or their initial meeting tomorrow. So I think it's a good

opportunity for the working group members, as well, to hear what you have to say and to get your views on this.

Now, just to go a little bit into the purpose of the session, of course, as you all know, on October 18th the Board issued the report of the board, "A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach". That report set out the Board's determination to move towards an outcomes-based approach to regulation setting four specific outcomes that electricity distributors should be focussed on.

The report described a need for a robust performance measurement system to support the new framework, including identification of specific performance metrics related to those four outcomes.

The Board determined that a new performance regime would include reporting of performance via scorecard, which would allow the Board, stakeholders, other LDCs and, most importantly, customers to understand how their distributor was performing.

The Board's report really set out for us a direction to follow, but today is the commencement of the consultation on the details, on the development of the performance measures, on the actual measures that we're going to use, the actual composition of that scorecard and the empirical analysis that will underpin the rate-setting options and the regulatory framework.

Scarcity could be that we have a number of initiatives involved with the implementation of the RRFE, which Brian

will get into in a few minutes. This scarcity could be more important to our whole initiative.

As a springboard for the discussion today, Board Staff and Larry will make presentations on the materials that were posted in December. Preliminary issues for consultation were included in these materials to help stakeholders prepare for the stakeholder meeting.

The purpose of this session is to give you, the participants, an opportunity to discuss these proposals and issues put forward by Staff and PEG and for our first opportunity to really get into some of the details.

They will form a key input to the working group that's meeting tomorrow, apart from working through the details of performance benchmarking and a total factor productivity work. And the work -- as I mentioned, the working group starts tomorrow. The materials for that group will be available on the Board's website to all interested stakeholders to stay informed of its progress.

The agenda that has been set for today provides for a presentation on each of the topics, then followed by a general discussion. We've also allowed time at the end of the presentations at the end part of this meeting to address any other general matters.

Are there any questions at this point? I'm not sure. Do we have the remote up yet?

MS. BRICKENDEN: We do have the visuals up that are being projected remotely. We will have to find out through the e-mail system if the folks who are participating

remotely can see them. They can hear us. They may not yet be able to see the visuals.

MR. FRASER: Hopefully that will get up and running shortly, but not wanting to delay things any further, I'm going to turn it over Lisa now, who is acting as facilitator for this meeting, and have her go over some of the logistics before moving on with the substance of the day. Thank you, Lisa.

MS. BRICKENDEN: Ironic to go over the logistics when they're not working as nicely as I might like. However, for those of you who are in the room, as you are aware, this meeting is being transcribed, so I would ask, when you do speak, if you would use a microphone, introduce yourself prior to speaking into the mic.

The details on how to participate, as I mentioned, remotely are being e-mailed out to remote participants, and I will be following up with that as soon as I finish this intro.

Remote participants, you are able to ask questions at any point throughout the presentations by, please, e-mailing our RRF at ontarioenergyboard.ca account. We have Laurie Klein here monitoring that account, and we will read out your questions as we receive them. When you do e-mail in, it would be very helpful if you were to provide your name in the e-mail so we can introduce you.

Before we begin, there are a few general housekeeping matters I would like to address. Many of you who have visited the Board know this already, but I do see a couple

of new faces. There are washrooms on this floor just outside of this room on either side of the elevator for your convenience.

We will have refreshments available throughout the day. We have ordered coffee and water for your convenience, and it will be just outside the second door.

Also, finally, the OEB has established emergency evacuation procedures. In the case of an emergency or a general alarm, I will suspend our meeting and provide you with the necessary instructions to follow in order to achieve an orderly evacuation, if necessary.

Are there any questions in the room before I -- all right. I would like to ask Brian now to provide a bit of an overview for us on some related initiatives that are going on to implement the Board's renewed regulatory framework. Brian.

UPDATE ON OTHER RENEWED REGULATORY FRAMEWORK IMPLEMENTATION INITIATIVES

PRESENTATION BY MR. HEWSON:

MR. HEWSON: Thank you, Lisa, and good morning, everyone. As many of you know from reading the report, the Board set out a number of key initiatives that were important to implement its policy direction in the renewed regulatory framework, specifically five initiatives regarding performance measures, smart grid, regional infrastructure planning and distribution planning. And what I'm going to do is give you a quick overview of where we are with those different initiatives, and I'm happy to

entertain any questions people have.

Performance benchmarking and rate setting, obviously this is the first day of the discussion and work on that initiative, so I don't really have anything further to say until after today.

On smart grid, as you will recall, the Board set out a couple of key determinations in the renewed regulatory framework report, and then indicated that it would reconvene the smart grid working group to advise Staff and ultimately the Board on how to address remaining issues related to smart grid development in the province. We did reconvene that working group in November. They met several times. At this point, the processes that Staff are working with the Board to develop a report, which we expect -- a supplemental report on smart grid that will provide direction to regulated entities should be out some time in the early part of February. That's our plan.

In terms of regional infrastructure planning, as you will recall, the Board determined that regional infrastructure planning should be undertaken in the province to assist in ensuring that there was coordination across transmission and distribution systems in the way that capital planning was being undertaken, and that assets were being deployed across the province. To undertake the development of that process, the Board instructed Staff to establish a working group that would report back as the working group to the Board. So that -- the important element here is the working group that has been established

is developing its report on how the process for regional infrastructure planning should be undertaken. And we will be providing that to the Board, we expect, early in February.

The other part of the regional infrastructure planning section of the report dealt with facilitating the planning process, and in fact what the Board identified were a number of the key areas within its own codes in the cost allocation process that should be addressed and looked at in order to try to facilitate regional planning.

A key element of that is to look at the definition of certain types of assets that are currently defined as connection assets and whether they carry out more of a transmission network function. We established a working group that has met several times and provided advice to Staff in terms of how to look at redefining certain assets for the purpose of future capital planning capital contributions, and that work is going to come out through a set of proposed code amendments, probably later in February. Those code amendments will probably include, as well, anything related to the regional infrastructure planning process that the Board believes needs to be dealt with through code amendments.

The last initiative I wanted to talk about is the distribution network investment planning. So in the report the Board established a couple of key things.

One, that distributors should be filing five-year capital plans that are integrated capital plans, cover all

of their capital spending in one aggregated plan. And in order to carry that out, the Board recognized it needed to first look at what the appropriate filing requirements should be to try and facilitate that, as well as what standardization and clarity the Board could provide in terms of the type of assessment tools and evaluation mechanisms that should be undertaken by utilities and provided as evidence in those filing requirements, so that the Board and stakeholders can evaluate effectively those five-year capital plans.

We established a working group that has met twice, and they've started the work, and on the first phase of their work they focussed on taking the existing filing requirements and existing parts of the renewed regulatory framework and looking at how to start to provide greater clarity to develop that five-year planning requirement.

The next phase of the work, which will start very shortly with the working group, is to look at the assessment tools and evaluation criteria that will be included as part of the filing requirements.

As well, once we've completed our smart grid work, the Board has completed its smart grid work, and the regional infrastructure planning process has reported, we anticipate the working group will assist us in developing the integration of those parts into the consolidated capital plans, and with the expectation that those capital plan filing requirements will be out by the end of February to inform distributors as they develop their applications to

be filed in October of this year.

And I'm happy to answer any questions, or otherwise we'll hand it over to Lisa to get on with the substance of today.

MS. GIRVAN: Lisa, if you read the screen, it says that people can't hear the audio.

MS. BRICKENDEN: I just noticed that. I was hoping that seeing the little bubbles pop up, I was pleased to see people were finally connecting, but no, I will have to –- unfortunately, not good if they can't hear. If I could ask one of my colleagues to please -- okay. It might be good if you -- I'm sorry for the inconvenience, but it might be good for us to take a momentary break so everyone out there can hear what we're presenting.

Perhaps we should break and start again at 10:00. How's that? Thank you.

--- Recess taken at 9:48 a.m.

--- On resuming at 10:00 a.m.

OVERVIEW BY MS. BRICKENDEN:

MS. BRICKENDEN: I believe Brian had passed the baton back to me. Thank you, Brian.

Over the next few minutes, I would like to provide a brief overview and review of the Staff proposal with respect to performance measures and a scorecard that we issued to you in December.

Just a brief overview reminder - it's been a while - that our process to date and our consultations to date have been at strategic level. This was important to help the

Board to determine the direction of changes set out in its October 18 report on renewed regulatory framework for electricity distributors. Consultations now, as Peter pointed out, are focussing on implementation of the framework.

Our focus today is on the performance and benchmarking elements of that framework. In its October 18th report, the Board described a comprehensive performance-based approach for renewed regulatory framework which promotes achievement of outcomes that will benefit existing and future customers.

The approach will better align customer and distributor interests, continue to support the achievement of important public policy objectives, and place the greater focus on delivering value for money.

Under this approach a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and the delivery of its services, which in turn may lead to reduced costs for consumers.

To commence work on implementation of the framework, Board Staff were asked to prepare a proposal as a springboard to discussion at this meeting today on measures that might best reflect a distributor's effectiveness and/or continuous improvement in achieving the outcomes and the scorecard as a means of organizing how distributors will report on their performance.

Slide 5, albeit rather busy -- I do apologize. It is

small, the text. However, it provides the complete summary of Staff's proposed measures. Before discussing those measures, I would like to briefly describe the columns in the summary.

The first column lists the four performance outcomes as they are set out in the Board's report, those being customer focus, operational effectiveness, public policy responsiveness and financial performance.

The second column identifies Staff's proposed performance categories. We propose these categories as a means of grouping the measures into meaningful buckets, so to speak, which are intended to help align the measures with the performance outcomes.

The categories on this slide are based on Staff's review of the existing standards and measures for electricity distributors that have been established by the Board, the distribution network investment planning consultations currently being carried out, which will consider asset management, and some scorecards from other energy companies in North America.

We look particularly at a scorecard from Memphis Light Gas and Water in the States, and we also dug into our archives and took a look at an Ontario Hydro services company scorecard, and we were also able to have a look at the IESO scorecard as they publish it on their website.

The last column lists the proposed measures in each performance category. Why do we select these particular measures? Many of them leverage existing standards and

measures in the RRR, other Board codes and/or the annual reports we publish. Some also appear on the other scorecards that we canvassed. A larger document that we issued along with this PowerPoint deck on December 6th, entitled "Measures For Electricity Distributor Performance", provides a detailed description of the proposed measures, along with additional measures that were listed in the codes or in the existing reporting requirements.

You probably noted, in reviewing this material in advance, that not all of the existing standards and measures for electricity distributors that have been established by the Board are included in Staff's proposal. It will be determined later, after we've completed these consultations and the Board has issued its supplemental report, whether the standards and measures not included will continue to be part of the Board's regulatory reporting requirements.

With respect to the proposed measures, broadly speaking, Staff selected them because they fit well, we feel, with the Board's criteria as set out in this report. Specifically the proposed measures are already well defined, whether in the Board's regulatory instruments or more broadly in business. They are common in other jurisdictions and seen on other scorecards. They are currently being reported and/or recorded by distributors today, so we have a building database to record on.

And many have consequences in place already associated

with them, and some have targets that the Board has set in relation to those measures.

Staff are proposing a few new measures, however, in the areas of customer satisfaction, cost performance, asset management and the connection of renewable generation.

The new measures proposed in the customer satisfaction category are commonly used measures. Also, customer complaints are currently being captioned through existing record-keeping requirements. Further, some distributors have indicated in these consultations to date that they do survey their customers, so we're not inventing something totally new. We are taking advantage of or leveraging information that is already critical to the business.

The new measures proposed in the overall cost performance category are also commonly used measures. Staff is proposing two capital measures that would complement the existing OM&A measures. We are moving towards a total cost approach to a window -- building a total cost window into the business and our benchmarking. So it would be good to have the capital measures on the scorecard.

Net plant cost per customer is a unit cost metric that provides an indication of how much a company has invested to provide service to its customers, and it can be derived using data that is already publish. The capital budget versus actual is proposed to align with and support the move to multi-year planning and approvals.

As you know, and I think Brian provided an overview of

the consultations going on, underway, with respect to distribution network investment -- that consultation will include discussions on asset management, and that will inform our work.

The new measure proposed in the connection of renewable generation category is intended to more closely align with load connection requirements. Staff notes that the information is already being captured through the Distribution System Code and RRR requirements, and that this kind of measure would support public policy responsiveness in relation to renewals.

The next two slides set out the issues for consultation on the proposed measures, but in addition to any other issues you would like to raise, we want to hear your views on this. This is important, because along with your comments today, any additional issues that you bring to our attention, this will collectively provide a work plan for the PPR working group. Colin?

MR. McLORG: Thanks, Lisa. Colin McLorg at Toronto Hydro. Really just a procedural question. If we have clarifying questions for you, would you like to have them now and reserve the more substantive questions for later? Or do you have any preference as to how questions are fielded?

MS. BRICKENDEN: Personally, no. If there's a clarifying questions, please, by all means.

MR. McLORG: Well, I did have one. It was on the prior slide, and it had to do with capital budget versus

actual. It just wasn't clear to us what exactly was being referred to as the capital budget. Is that the Board-approved budget, or is it the company's own internal budget, or how is that to be understood?

MS. BRICKENDEN: We don't know yet. My personal view is I think logically it should be Board-approved. And the company's performance towards that commitment, those commitments are what will be built into rates going forward, and so it would be good to have a trend on the performance against that commitment. That's the intent.

MR. McLORG: Okay. Thanks.

MS. BRICKENDEN: But I think we need to discuss that further with the working group. It would be helpful.

MR. McLORG: I don't want to verge into a substantive discussion right now, but again in the nature of clarification, just with respect to customer complaints, we were wondering whether there is going -- and maybe you'll say this is to be determined. Whether there will be any narrower definition of that, because utilities are subject to -- because they are the front end of contact with all customers, utilities tend to get a lot of complaints about things that don't have to do with utilities, but rather have to do with commodity costs or energy retailers or something else like that.

So I'm not sure if that's really a clarifying question or a substantive question, but the issue is whether or not there is going to be any process to filter or qualify complaints for inclusion in the scorecard tally.

MS. BRICKENDEN: I think, yes, there would have to be. Don't have it now, Colin, but there would have to be. Personally, I think that you would only ever want to have escalated, like -- we would have to have that conversation.

From what I've seen on the scorecards I've looked at, they're not referring to the host of thousands of calls that come in and are resolved on a daily basis. It's significant -- and escalated issues, recurring issues, but...

MR. McLORG: Okay. Well, that's very helpful. Thanks.

MS. BRICKENDEN: It's on our agenda for the working group.

Are there any other questions, clarifying questions or comments? I would like to open up the floor and get thoughts on some of the issues for comment that we have set out on the material I've presented to date.

What are your thoughts? What was your first reaction when you read this? Do the proposed pressures align well and reflect your effectiveness as a distributor, or from a stakeholder standpoint, your view on the effectiveness of the distributor in achieving the Board's performance outcomes? Judy?

Q&A/DISCUSSION SESSION

MS. KWIK: It's Judy Kwik for the Power Workers' Union. One measure I notice was missing that I think should be included is line losses.

MS. BRICKENDEN: Line losses? Okay. Are there any

other views on that? Colin?

MR. McLORG: As several of us believe, it's very important to have safety on here, worker safety and public safety.

MS. BRICKENDEN: How do these measures -- I'm curious -- how do these measures align, if I might ask the distributors in the room, with the things that matter to you, the things that you have on your scorecards or the things that keep you up at night? Carm?

MR. ALTOMARE: Carm Altomare, Hydro One.

When I looked at this package, I thought one of the missing ingredients was to have a balanced scorecard. I agree with Colin that safety should be added in there, but when you put a scorecard together, it should be focussing on what your strategic objectives are of the utility, and then the measures on tracking those objectives to see if you're meeting those objectives at the end of the day or at the end of the five years.

But another area may be environment; it's another part that's missing. And I don't think we should be overly focusing on costs, because it takes away from the balanced scorecard approach. I know traditionally we were always focussed on costs and we were always focussed on financial measures, and then shortly after, we introduced reliability.

But when you look at the industry south of the border, with the balanced scorecard approach by Kaplan, it certainly emphasized the need of how to effectively develop

a scorecard that looks at all the areas of the utility.

So I would strongly recommend that we use a balanced scorecard approach.

MS. BRICKENDEN: Are there any other thoughts on that? Colin?

MR. McLORG: I wonder if I could engage in a slight discussion with Carm. I don't mean to derail anything, but again for clarifying, Carm, is it your belief the utilities own internal scorecard should be identical to the one that is used for regulatory purposes? Or can you see that there would be possibly a regulatory scorecard that would be probably common to all utilities, and then utilities could have their own scorecard that might overlap to a very high degree with the regulatory one, but still could be conceptually distinct?

MR. ALTOMARE: I think we're in the early stages of that development, and your point is well taken. I would envision that you would have a regulatory scorecard, and there should be some linkage with the internal scorecard, because in essence, what's the purpose of the scorecard? It's to monitor how we're doing in meeting our strategic objectives, but it's also, more importantly, in trying to drive the right behaviour in the company.

So there has to be some alignment there in how we do it. I'm pretty open at this point, but I think that's a discussion for down the road. And realizing that with the regulatory scorecard, some of the measures are already included in our reporting processes, like reliability and

customer service metrics, and some of these other metrics that are coming to the forefront -- for example, customer complaints -- I couldn't agree with you more, Colin, that customer complaints may not necessarily be a good measure for scorecards.

But I think that's the whole purpose of the working committee, to have that discussion.

MR. McLORG: I was only thinking -- I agree with what you're saying. I was only thinking that there could be some internal targets that a company would legitimately have. Attendance might be one of them, if a company has an attendance problem with some sectors of its staff, but that wouldn't necessarily be of direct interest to the regulator or customers per se.

MS. BRICKENDEN: Jay, you had a question?

MR. SHEPHERD: Yes. My response to Colin's question is you would have to have a pretty good reason for the goals of the utility, which are expressed in the scorecard, to be different from the goals of the regulator.

I take your point, whether for reason of granularity or for reason of metrics that are not outcomes based, but are, rather, process based, you might have situations where you have additional ones. I think that's fair.

MS. BRICKENDEN: Bill?

MR. HARPER: Just to show that there's no unanimity between intervenors, just like there's no unanimity between -- actually, because when Colin raised his question, I had -- Bill Harper, excuse me. I had a similar view in terms

of whether the two had to be precisely the same in terms of you had a regulator which has a stated set of objectives in terms of reasons why it is regulating which, to some extent, may not match.

Another example that came to mind is I know utilities that have scorecards that include -- very highly in terms of issues around employment equity, First Nations hiring, things like that, which may not sort of -- which may not attune themselves as well with the regulator's perspective, but, depending on the utility you have, it may be very much fundamental to what they believe are the things they should be doing.

One way to do that may be to have -- if you wanted to, maybe to have a scorecard that picked up the regulator's things and maybe has sort of a little box at the bottom whereby, if an individual utility wanted to put something in there that was specific to them that they thought should be -- you know, help balance the whole thing out, they could fill in that and that could be given a weight up to a certain amount, sort of thing. You know, that's just an idea to throw out for consideration.

MS. BRICKENDEN: Thank you, Bill. Just a reminder, too. I know Nancy has drawn a little map of the people who are sitting in the room, but could you please announce your name as you enter.

MR. SASSO: Andrew Sasso from Enwin Utilities. I was going to get to it a little later under 7(c), which is about the scorecard features. I think it makes sense that

there be predominantly a fundamentally singular scorecard. That might be 80 percent, 90 percent that's common to everybody, but I guess our thought is, when we're talking about when they should be set and what should the weightings be and all that kind of thing, that in a cost of service proceeding, or if you are on annual IR it might be once every five years or something, you would establish that on a very utility-specific basis. And it should align very closely to your capital plan, your operating expenses, the issues you're facing as a utility and that you're seeking rates for.

I mean, I think that is the point, but I think we see in many utilities those priorities may be different, and certainly the weighting among those different priorities may need to be different because of the age of the utility, the nature of the customers, the different challenges they're facing from time to time.

So I know it jumps ahead a little bit, the question of weighting and so on, so I don't mean to get it off track, but I think there does need to be some utility-specific consideration given to how the scorecard is created.

That being said, I think this is really, really good and I think that, at least for us, certainly once you include safety and line losses, it does align very closely to the sort of things that we would consider.

MR. HOEY: Lisa, it is Patrick Hoey with Hydro Ottawa.

I tend to agree with most of the people that there be a high degree of alignment, but I do not believe that there

would be 100 percent alignment, because the scorecards, at least for our company, will be developed by our board of directors and by our shareholders, and they may have different priority in particular areas that are different than the set here for regulatory purposes, and that's because this scorecard tends to focus on customer and not necessarily on the shareholders' needs, as well, which will have to be addressed.

So there will be a high level of alignment, but I don't believe there will be total alignment.

MS. BRICKENDEN: Gia.

MS. DEJULIO: Thank you. It's Gia DeJulio from Enersource. I think most of us are very pleased to see the focus on customers in this, and we're very intrigued by the customer survey measure, but I'm worried about the cost of that, because many of us already do our own surveys, not all of us, though, every year, and one would expect this would be an annual requirement.

We're worried if that would then add significant cost to all distributors and, hence, for all ratepayers, to conduct a survey on an annual basis and, you know, how detailed would this survey be. Those of us who already conduct our own customer surveys, you know, they are quite -- some of them are quite long and they are for very specific purposes. And, you know, we ask questions that probably generally, you know, the OEB and constituents wouldn't be that interested in knowing, you know, things like comparing us to your gas distributor: What do you

think of us now?

I would really want to see obviously a common questionnaire or survey for all the distributors in order for the OEB to make valid comparisons among that group, and just very concerned about what the cost might be for that.

MS. BRICKENDEN: Thank you, Gia.

MS. BUTANY-DeSOUSA: Indy Butany, Horizon Utilities. As a follow-on to Gia's comments, again, I would second that we are happy to see the focus on the customer, but in the area of a customer survey, at the end of the day there is an issue of comparability. So in the absence of the OEB of taking on the role of having that standardized approach to a survey, you end up with an apples-to-oranges comparison as between distributors, and it's not necessarily the case that every LDC in the province conducts a customer survey, in any event.

The other thing that we've seen from customer surveys that we've conducted, depending on the facilitator of that customer survey - again, it goes back to whether or not the OEB is conducting a survey as a standardized approach across all LDCs - is there is something to be said for the timing of the survey. Is it close to a rate change or not, a comparison to other service providers, as Gia has noted, with respect to gas distributors, gas marketers, and, also, in addition to that, there is the issue of: Are you offering the customer a chance to say no answer, or are you offering the customer only the option of providing you with a yea or nay or somewhere along the scale?

So I think if the OEB is going to be exploring customer survey and taking on that role, there are a number of different areas that need to be evaluated and addressed prior to going to a standardized approach.

MS. BRICKENDEN: For sure, Indy, and what I personally noticed in looking at the literature and other company surveys, it also depends on what is of strategic importance to the company at a certain point in time.

As each company is going to be trying to assess what its customers' value, that may not be the same for every single company across the province. Not every single company across the province has the same customer base.

So sensitive to the fact that each company will have a different profile, so to speak, in terms of customers, and also will be in a different place in its development or strategic investment cycle, it may have to focus on specific areas in order to get a handle of, putting little quotes around it, customer satisfaction within that context, that company's context.

I wanted to put that out there that a generic one-size-fits-all may not be appropriate. Judy?

MS. KWIK: Judy Kwik for the Power Workers' Union. I think in doing the customer service, it's really important that the customers understand the context of the survey, and I think that's probably best done through a willingness-to-pay survey, which the Board has already embarked on such an approach in the service reliability consultation, which I think is a really good start, because

it provides the Board with the feedback on or an understanding of what the customers need and what they expect, which of course is the basis for the cost, as well as reliability standards.

So I think a willingness to pay, as the Board has already started doing, is the way to continue.

MS. BRICKENDEN: Thank you, Judy. Carm?

MR. ALTOMARE: Yeah. Talking about customer sat, it's been my experience in using that measure, the scorecard, it's very -- it's driven by perception of the customer of the service. It doesn't necessarily reflect on the service that is provided by the utilities, and that's why I would encourage utilities to continue the customer sat surveys as they have done traditionally, because they are very useful. They do help pinpoint some of the weaknesses or some of the areas for improvement.

But for a regulatory scorecard, I would promote the use of the customer service metrics. There are some of them that are in there that we are already reporting on on an annual basis, and to me that would be more reflective of a regulatory customer service metric than customer sat, because of the points that were raised earlier. You know, would you do a survey across the whole industry in Ontario? And again, you have the different makeup of customers, you have the different requirements by customers, and it wouldn't be fair to make any comparisons from that information that would help individual utilities or even help the regulator.

So I would say continue with customer sat for individuals, but let's look at more the customer service SQIs that we already have.

MS. GIRVAN: Julie Girvan, Consumers Council of Canada. I tend to agree with that, as well, and I think another important consideration for any customer surveys is timing. If you do a customer survey after you've had a rate increase or commodity cost increase, that could certainly reflect the results of the survey. So timing is important.

MS. BRICKENDEN: Carm?

MR. ALTOMARE: One thing I did forget to mention was that in Hydro One, we've started doing transactional-based surveys. For example, when we connect a customer or provide an upgrade or do forestry work or even the service that we provide by our call centre, we have an agent that goes out and surveys customers. It's just a very short survey, but it's based on the service that we provide.

And to me, that's more reflective of how well we're doing. And at the same time, we use that information to improve that process, whether it be a connection or an upgrade or forestry work or whatever.

So just to share that with you.

MS. BRICKENDEN: That's a good point. Actually surveying the customer's experience at the time of the moment of truth is very effective while it's fresh in the memory of the customer, and it's less apt to be biased, because they're not trying to scan back in their memory and

recall what happened.

MR. BAKULEV: Alex Bakulev from Toronto Hydro.

A question regarding cost-performance measures.

So we have three measures, and it seems like one of those measures, which is, I believe, based on the econometric model, kind of includes other two measures. So econometric model I believe includes OM&A, that planned cost, and then it's not just a per-customer basis; it kind of considers other outputs of the utilities.

So the question is: Do we need three measures, or we can just use one measure, which is a way better representation of the cost performance of the utility? What are your thoughts on that?

MS. BRICKENDEN: I'm sure Larry will fix me if I get this wrong, but the efficiency ranking, so to speak, is a bit of an all-in total cost metric. The individual components, however, can be useful in looking at the context for that efficiency ranking. So that you're looking at the components at a high level that go into establishing that ultimate.

MR. BAKULEV: Maybe do we want to consider not just per-customer basis, but let's say per-kilowatt delivery, right?

MS. BRICKENDEN: Possibly.

MR. BAKULEV: One of the station is that one customer could be a high-rising building, which includes about 1,000 customers in. So a better representation could be kilowatt deliveries, rather than just the customer basis.

MS. BRICKENDEN: Per customer, yeah.

MS. NANNINGA: Just on the ratio for net plant per customer -– oh, sorry. Margaret Nanninga, Kitchener-Wilmot Hydro.

As far as the net plant cost per customer, without getting too deep into the ratios, I guess I have a concern. Some utilities have a lot of transformer stations and others don't have any, and so I think it could have a big impact on measurability or comparability of that ratio.

MS. BRICKENDEN: Thank you.

Richard?

MR. STEPHENSON: Richard Stephenson for the Power Workers' Union.

When you're looking at this scorecard, I think it's important to take a step back and to realize that one of the fundamental purposes of the scorecard is to incent certain behaviours which the Board perceives as being good.

So you have to be mindful about the fact that like standardized testing in schools and you wind up having kids being taught to the test, you would expect a rationale utility to perform according to the scorecard. So it's just as important to understand what's not on the scorecard as to understand what is on the scorecard, and because a rational LDC would focus its attention on achieving good marks on the things that are being scored, presumably at the expense of things that are not being scored.

And so while it's credit it critical that the Board be mindful of its statutory objectives in terms of the things

that it's measuring, if that has the result of achieving socially undesirable impacts, then that's a bad thing and something the Board has to be mindful of.

So for example, one of the issues that was raised earlier was employee and public safety. You don't really see that in the Board's statutory objectives very much, but it is entirely foreseeable that you have -- when you have a whole lack of objectives and LDCs quite rationally pursuing those objectives, something else has to give, and if somebody can meet this list of objectives and the consequence is that employee and public safety suffer, is that really an outcome that the Board wants?

Same thing with environmental -- adverse environmental impact.

I appreciate that there are other regulatory schemes out there, but there's other regulatory schemes out there about all of this stuff, or a very significant part of all of this stuff that is governed in some fashion or another by a variety of things.

So I just think the Board has to be very mindful of the fact that what it's doing will incent behaviours and it has to be conscious of unintended adverse outcomes.

MS. BRICKENDEN: Thank you, Richard. Judy?

MS. SIMON: Judy Simon from LIEN.

I have some comments on the measures, as well as on the overall scorecard.

I wanted to say that LIEN's pleased to see the public policy responsiveness addition. We would like to suggest

that there should be an addition to the performance category related to LEAP. There's probably a ministerial directive you could refer to, and at minimum, there's the Board's own initiatives. I think that that's missing.

And the new amendments to the RRR certainly reflect a strong interest in the Board in getting more granular about the data, residential and low-income data, so I think that should be reflected in the measures and then ultimately in the scorecard.

As far as taking this a step further, it would be helpful if the working group were to also consider increasing the granularity of the reconnection service quality indicator, to reflect the additional reporting requirements related to the separation of residential and low-income, for example. It might be worthwhile to know the number of low-income arrears management programs that are put in place with reconnection, versus the total number of low-income reconnects.

Things like that might be useful to consider in the working group, and then come back to the rest of us with some suggestions.

In addition, there's -- as far as handling inquiries, I agree with the point that was made about adding some granularity as well as some precision to what those inquiries and what those complaints are about. And to tie those specifically to the categories and performance outcomes would be helpful, because I'm quite aware that the companies get all kinds of inquiries that they track that

don't really have any direct bearing on what's in their control.

In that vein, it would be good to track, perhaps at a greater granular level of detail, the CDM customer service that a lot of utilities - probably most, if not all the utilities - provide. Many of their CSRs spend a lot of time dealing with customer inquiries and assisting with programs that add value to customer service, and that's not tracked separately and it may be of interest to the Board. It links somewhat to public policy responsiveness, but customer service wasn't directly flagged in the directive. So that might be something to consider, as well, because from the customer perspective there can be significant value added there if the issues are handled properly. It's not only -- this is for all customers.

And as far as the customer satisfaction survey -- do you want me to keep going or did you have a comment on what I was going to say, Colin?

MR. McLORG: Sorry. I was waiting for my microphone. I was going to ask another perhaps rhetorical but hopefully clarifying question, but it goes to fundamentals. What is the difference between a discussion of reporting requirements and a discussion of the scorecard?

There has to be some kind of difference between a scorecard and a whole set of reporting requirements, and I don't know what basis Board Staff or the Board might have for distinguishing between what's conceptually eligible to be on the scorecard and what is nevertheless of interest to

the Board and may form part of a reporting requirement, but isn't part of the scorecard per se.

MS. BRICKENDEN: Well, I think the test that Staff have been using in order to filter is envisioning a pyramid, the bottom of the pyramid being: All in, all comprehensive, what are the things that the Board will effectively have in place to regulate the company? And also in there, blended with that, but not necessarily the Board's oversight, will be the things that also manage the business, so it's kind of sliced in half, things that are of regulatory nature, things that are of critical business nature in serving the customers.

In the middle part would be the operation -- the next level is the category where it's -- what are the key operational, functional things that the business and the regulator want to keep tabs on to have a handle on the directional success of the company, and on the other side are the more customer service centered type elements, the more outward looking.

At the very top are the critical things that, quote, might keep you up at night. What are the things, the hot buttons so to speak, that are really -- I won't say safe and sure, but generally we're confident that they are the indicators of -- the true indicators of the success of the business and that will give comfort to the Board that everything is on track. It's a subset. It's not a case that everything is going to fall away. There are dependencies. There are maybe two words on a scorecard

that beneath that might have four data elements.

So there might still be that system relationship, Colin, where there are going to be ongoing reporting requirements that then are fed up into the scorecard, but it's not intended -- the scorecard in and of itself is not intended to be the full suite of the Board's regulatory framework, and I do not anticipate that the codes are all going to wind down and the RRR code will turn into four bullets as a result of this exercise.

However, if at the end of this exercise we find that there is information that it really isn't contributing to the Board's regulatory oversight, it's not contributing to what we think is measuring a distributor's effectiveness and continuous improvement in the performance outcomes the Board has identified, why should the utilities be reporting it?

So there would be a rationalization at that point to focus on the things that do matter. Does that help at all? Colin?

MR. McLORG: I think that is helpful for me at least, Lisa. What I understood from what you're saying is that there would be a difference between what companies report on as a whole and the subset of those things that would be included in the scorecard. I also understood from what you were saying that, you know, while it's true this might be an occasion for the Board to look at what's being reported and see whether that can be streamlined hopefully, and so on, it's nevertheless the case there are going to continue

to be things that the Board is interested in, even just from a policy or information perspective, a lot of things perhaps to do with developments in, you know, low-income service, and so on, or how many customers are fitting into that category, without being directly part of a performance scorecard.

I guess it is very difficult to say abstractly what the difference between those two categories is or what characteristics of a particular item make it eligible for inclusion on the scorecard, but I just was concerned that we not start with the implicit assumption that everything that's now reported is somehow a candidate to be on a scorecard, because I think a lot of those things represent useful information to the Board, but wouldn't necessarily go to performance, per se, of the utility.

MR. GUILBEAULT: Jeff Guilbeault, Peterborough Distribution. I just wanted to make a general comment that we should keep in mind the boundaries of the scorecard and the boundaries of the OEB's jurisdiction, and I guess, oddly enough, I would argue against putting safety on the scorecard, because we do have other regulators that regulate public safety, the ESA, for example, which is actually enshrined in the Electricity Act, I might add. Public worker safety, we have the WSIB. We have the Ministry of Labour, under the Occupational Health and Safety Act.

So I would caution against adding things that are probably outside the jurisdiction and interest of the OEB

on the scorecard. And environment probably is the same thing, too. We have the Ministry of the Environment. We actually have two regulators. We have a provincial one and a federal one.

So I don't think I would want to add OEB to that list. That's my comment on...

Line losses I think is a good idea, but the other two I'm not so fussy on.

MS. BRICKENDEN: Thank you.

MS. MCLORG: Lori McLorg, Veridian. Just in response to that, I think the idea of raising safety, in particular, it goes to what Carm was speaking about, a balanced scorecard, that a utility has to balance out where it puts its resources.

And if we have a scorecard that we are to follow and to meet targets on, again, also, as somebody else pointed out, you might get unintended consequences and you wouldn't want to see that resources that the utility should be putting into things like safety are not on the landscape for things like rebasing for your cost structure for how you run your business on a scorecard with the regulator, because while there are other entities that deal with safety, they don't determine how we run in our cost structures and how we run our business.

So I think it would be an error not to have something like that.

MR. GUILBEAULT: Just to further the discussion a bit, safety is front and centre on our corporate scorecard, so

it's not going to get lost, and any good utility would not sacrifice that just to please a rate-based regulator.

So I don't know that that's really a big issue. I think it's still -- I think it's an important factor that you would maybe use as evidence towards a rate case, but to be on a scorecard seems a little out of jurisdiction in my view, anyway.

MS. MCLORG: That seems a little bit contradictory, that if it's good utility practice, should it not be on the regulator's landscape? And if we feel that it is a key, core business value when we would be putting it on our internal scorecards, I think it should have some consideration.

MS. BRICKENDEN: I think this is an important conversation to have, because even Staff, when preparing this, had a number of back-and-forths amongst ourselves.

We're not trying to supplant or replace the corporate scorecard. We're not trying to create the be-all and end-all and balanced scorecard for electricity distributors in Ontario. Personally I don't feel that would be appropriate. That's the purview of the company that will have to –- that scorecard will of necessity evolve over time, consistent with the company's strategy. That's what happens to all of them. That's why the balanced scorecard is such a beautiful tool.

Reporting in a similar fashion and aligning the regulatory reporting and this scorecard or report card -- whatever might be a better term for it -- I think is

important that it be aligned and consistent, but does it need to replace? Is it appropriate that it replace? Is it appropriate that the Board try to say: Here are the things that you, as a business, should focus on?

Maybe it's more important that the Board say: Here are the things that are of a concern from a regulatory standpoint. Here's how we think your effectiveness in delivering to these outcomes is best measured, consistent, hopefully, with how you measure yourselves and your business.

And I think as Colin said, it's a subset, not the replacement.

Others' thoughts on that?

MR. McLORG: I was simply going to add, to amplify or to add to the points that have been made, that I think it certainly is of interest to the Board and it certainly is of interest to utilities.

Whatever it is that we do that has cost consequences, cost consequences will be reflected on rebasing in revenue requirements and cost consequences will be reflected in cost performance, which is clearly of interest to the Board.

So I certainly think that anything that has cost consequences that are material would, sort of on a general basis, qualify at least for consideration here.

MS. BRICKENDEN: Before I take any more questions, I thought I would check in with Laurie to find out if anything has come through via e-mail.

MS. KLEIN: Thank you. I have one question. It's from Jim Huntington, Niagara-on-the-Lake.

He has a question on cohorts. His question is:

> "Density of an LDC's distribution system will have a major impact on OM&A. Our next closest cohort has a customer density twice that of our distributor, while the other three have multiple densities. Will there be a better recognition of the effective density as a cost driver in the future?"

MS. BRICKENDEN: I'm wondering if we could hold that question until Larry is presenting on the benchmarking, if that is okay. If you could mark that one for...

MS. KLEIN: Yes.

MS. BRICKENDEN: Thanks, Laurie.

MS. KWIK: Another suggestion for another performance -– Judy Kwik, Power Workers' Union. Another performance measure if -- a measure of the distributor's readiness to manage unforeseen circumstances. You know, I think about storms like Sandy coming along, and this is a kind of measure that if you leave it off might get sacrificed. And it would be distributors showing their flexibility to accommodate unforeseen major events.

MS. BRICKENDEN: Are you talking about emergency preparedness?

MS. KWIK: Yes. I'm not sure how you score it, and we'll have to have that discussion. I'm sure there's a way of doing that.

MS. BRICKENDEN: Thank you, Judy. Jay?

MR. SHEPHERD: Yeah, I -- the question has been raised by a number of people now, issues of how to reflect in the scorecard distributor diversity. We've been sort of down in the weeds talking about individual measures, but we haven't stepped up to the higher level and said: Well, how do we want to design the scorecard so that it achieves the objectives?

If you're -- if you're doing comparisons just for diagnostics to find out what the problems are, then you don't really have to worry about making sure that every metric is fair, because each metric is telling you a different thing.

But if the scorecard has consequences, which presumably it will, then you have to -- then fairness matters. And it seems to me that there are three ways that you can reflect distributor diversity, and I'm trying to prompt a discussion about this.

One is you can design metrics so that they adjust already, so that a metric of OM&A per customer already factors in things like density and stuff like that, or customer mix, let's say. Or you can choose enough metrics that if you're hurt on one, you'll be helped on another, so you add things like cost per kilowatt-hour. Or you use cohorts, comparator groups, to ensure that you're only comparing people with -- or utilities with like utilities.

All of these have advantages and disadvantages, and I'd be interested in hearing people's views on how that

should be done.

MS. BRICKENDEN: Thank you, Jay. Maurice?

MR. TUCCI: It's Maurice Tucci, EDA.

I just wanted to flag that. We did have some discussion about these things, net plant per customer, OM&A per customer, and Jay's right. There are differences between utilities, and there'll be a lot of difficulty trying to make direct comparisons between utilities using these measures.

We recognize that these measures are relevant, I guess, in terms of comparing us to other jurisdictions, because they are measures used in other jurisdictions. So they're sort of relevant. And OM&A and net plant are -- as long as you have both of them there, you're sort of capturing the trade-offs between them.

But we were struggling, trying to figure out how to make these better, like Jay's suggestion. It starts getting into a benchmarking exercise then, and we fall into that trap of having a number that doesn't compare to any other jurisdiction anymore.

Are we going to keep these numbers so that we can compare it to other jurisdictions, and then put a little asterisk and say: But, you know, you allowed the utility to explain why its net plant maybe is higher or lower, because we all know utilities have different age of assets, different densities. There's a lot of things that are making them not directly comparable. But if you -- if you average it across all the utilities, it might be a relevant

number, a weighted average across all the utilities, but by itself when we're trying to compare between them, it's problematic. And then the LDC might have to put a footnote and explain: Well, I know my costs are higher or lower because of this reason.

MS. BRICKENDEN: That actually might be a good segue, if I may, to quickly jump ahead to the slide that discusses that as a feature of providing the context for the information provided to the Board and published on a scorecard. If that's okay with folks, because this does delve into some of the questions we wanted to get at the end of this slide presentation. Gia?

MS. DeJULIO: I would be remiss if Enersource didn't thank Jay for his suggestion there, because certainly we are on the record as to our frustration with the current measures, because they penalize some LDCs who may have a very large throughput and a relatively smaller number of customers.

So if there is -- if we're opening up the discussion to including other types of metrics, such as total dollars per throughput and different metrics, obviously we're very amenable to that.

MS. BRICKENDEN: Definitely. Yes?

MS. YAMPOLSKY: I have two probably technical questions. Well, one is really -- if one of the purposes of the balanced scorecard is to incent some behaviour by utilities, I personally was a little bit surprised to not see here anything related to smart grid, which is

apparently very important. So I wonder whether there was any reason to not include anything related to it, other than the fact that we still don't know how to measure it. That's probably point number one.

Second one, it is really everything here, all these measures, they're point-of-time measures. Again, except maybe to some extent efficiency ranking, I don't see any measure of trend.

Now, internally we would say our growth over the years, or cost performance over the year. Again, I don't see it here. Any thoughts about this?

MS. BRICKENDEN: Yes. Lucky Brian left the room as you asked about these. However, the Board in the October 18th report has determined that the smart grid investment activities are to be treated as regular run of the mill capital investment activities. So good observation. No, we have not explicitly put a smart grid element on the scorecard, but it will be an important component in the distribution network investment consultations that are going on right now, and something might come from that under the asset management category. So, no, we do not have anything yet.

With respect to point-in-time and trend, you are correct. In the Staff proposal, however, just jumping forward here, we have proposed a relatively simple presentment of the scorecard. There is a larger copy of this small graphic image hopefully in your package that we issued on -- I think it's printed off on a legal 11-by-17.

We do propose presenting five years, the five most recent years of information, in order to reveal the trend, and we have also -- while it's very hard to see at the bottom of this slide, we are proposing that there be something on the scorecard to provide an indication of what the direction is, how the direction is -- performance is pointing, whether it's keeping steady, it's increasing or decreasing.

Hopefully, there will be a trend and it would be the most current five years. Staff proposed five to align with the Board's policies, as set out in the report, to move towards a five-year rate-setting cycle and the five-year investment planning cycle.

And, in addition, just leveraging off of Maurice's comments, Staff have also, on the next slide - I believe it's slide 11 - provides a brief summary of the key features of Staff's proposed scorecard.

A number of distributors have expressed concern in consultations to date that it's important to understand the full context of what the distributor is reporting at any point in time.

We've included in our proposal kind of a management discussion and comment section. And I have found that this does exist, generally speaking, in the corporate scorecards that I've seen, so it's not unusual.

One thing that I would like to put a bit of a pitch in at this point, if you will bear with me, it would be really helpful to our working group if there are some of you in

the audience here or even out listening across the province if you would be willing to share with us what's on your scorecard. What is it that your board is asking you to keep an eye on? It would be helpful for us to have a few samples to work with in the working group.

We will be asking the utility members to share, but if there are others that would also be willing to share, it would be helpful to us. And not many publish them, because I do understand that they are internal company documents.

MR. HARPER: It's Bill Harper. Because I'm part of the working group, I think I would be interested in that, but also particularly interested in terms of if you have a scorecard, not only what's on it, but more precisely how you measure it. What is the measure that you use? Because that's probably particularly interesting as we get down to the nitty-gritty of it?

So I'd really encourage response to what Lisa is saying. Not only what is on it, but also how it's measured, as well, would be really useful.

MS. BRICKENDEN: Colin?

MR. McLORG: Lisa, a couple of remarks responding to what you just said and concerns that Jay raised.

I'm speaking only for myself here, because we haven't had a complete chance to digest and discuss all this, but it did seem to me - and maybe I took this as an unconscious assumption - that this scorecard per se would mostly be a tool for the Board to assess a utility's own performance relative to its history, and that the problems that Jay

raised and Maurice mentioned, and other people have mentioned, concerning the comparability of scorecard results weren't really meant to be addressed in the scorecard, per se, or within that context, but would be the subject of the analysis that goes on as far as benchmarking, and so on, is concerned, where you actually have cost drivers and explanatory variables, and so on.

I see what your point is concerning the MD&A, but to me that would be a vehicle in which a company could describe trends, as it does in its own financial statements, year over year or discuss extraordinary developments that occurred in the current period, or whatever.

But I'm not aware that anyone's MD&A contains any discussion, in the financial statement context, of why certain costs are at a level that's either higher or lower than someone else's. All the MD&A material is exclusively self-referential. So I'm just really mentioning that in my unexamined assumption, I had thought that the benchmarking analysis, the cohort analysis and all that whole branch of the discussion, would go to issues around comparability between utilities, whereas the scorecard would be an indicator for the utility itself, because it is virtually impossible, in my opinion, to adequately correct in a summary way the differences that would exist between Hydro One and Newmarket Hydro, or whatever.

MS. BRICKENDEN: I understand. And just getting back to something Jay commented on previously in getting the --

and we don't know yet, so I wish I had an answer for you, Colin, but we need to discuss this in the working group, because it would be ideal if we weren't going to be creating excess metrics that aren't multifunctional.

If a metric can be used multi-purposed, that would be great; i.e., first, it might be used in an application to estimate a trend level from one year to the next; secondly, gee, that is a good one, therefore, to report annually on the scorecard.

We don't know. I'm just giving you an example. Thirdly, that exact same metric can feed into our empirical analysis that Larry is doing. We don't have to create a new number for Larry. I would hate to have our empirical analysis, the work that we do to actually do efficiency rankings, rely on inputs and assumptions that are derived differently than what the Board is going to be using to inform itself in the context of an application or on annual reporting.

So from system standpoint, I think there's benefits to having consistency there. With respect to scorecard-to-scorecard comparisons, I think I agree with you that right now, until we have a more detailed discussion on what are the components and how -- as Bill pointed out, how are the individual measures actually derived and estimated, the $6 million question is number 8.

One of the things we've been skirting around a little bit is report cards will say you got an A or a B or a C, or your number is 3.5, 25.6 or whatever. There is no

averaging. There is no scoring, per se. It just is an objective report of data and each data element may have a time series.

As soon as you start aggregating that information together and trying to assign meaningful weightings to it - and this gets a little bit to, I think, what Andrew was saying earlier - that's very complex. And I don't know yet if we're going to go there, Colin. I think it's too early days, but on the working group we need to explore that. If we do, how do we do that? How do we do it consistently and fairly? Or, as Andrew pointed out, is it something that perhaps the utility would assign based upon its own circumstances and just report it to the Board so that it would be consistent year over year for that utility?

MR. McLORG: Just a couple of quick responses, Lisa. I didn't, first of all, mean to suggest that the information used for the scorecard and the benchmarking needed to be exclusive in any way, or that it wouldn't be a benefit to have everything calculated on a uniform and consistent basis. I didn't mean to suggest that.

Secondly, I think it's our view -- and I'm aware that other utilities feel this way, as well -- that there certainly needs to be weighting of the individual items on the scorecard to reflect their relative importance. I think that's a very different question, and I agree with you that that would be a very demanding and judgmental exercise.

But I think that's a very different question than the

one that is involved with somehow comparing one utility's scorecard to another utility's scorecard. And I don't think it would be meaningful, for example, to take -- to show on any scorecard what the average score across the province was, because that would basically be to disregard the benchmarking of the analysis.

MS. BRICKENDEN: Jay?

MR. SHEPHERD: I actually agree with Colin. Did I say that?

[Laughter]

MR. McLORG: Mark the date.

[Laughter]

MR. SHEPHERD: Yes. But I guess I think that inevitably scorecards will be compared with each other, and I'm not just thinking within the regulatory process. Your own boards of directors are going to ask to see the scorecards of other utilities that they think are comparable, and then they are going to whack you around if they think you're not performing up to the peers.

This is going to happen. Once you have a standardized rating system that's approved by the regulator, people are going to use it. Customers, your boards of directors, your internal management; it's going to be used by lots of people.

So I think we have to anticipate that and make sure that the final result is not as easily open to mistakes and abuse. That's my -- I'll give you an example.

Is there any reason why the scorecard can't have a

measure of utility attributes? Things like a density measure, things like a transformer ownership measure, where you segregate out the transformer ownership component of capital measures, things like a customer mix table. These are all simple things to do, and I think you might be able to get a package that would give you a general description of what type of utility this is.

I'm putting that out as a possibility.

MS. YAMPOLSKY: I actually agree with Jay. As much as we think all this is not comparable and utilities are different, our board of directors, our executive management would ask us: Can we see what Enersource is doing? Let's see Enersource compared to PowerStream, what Toronto Hydro is doing. We are going to be there.

But I think that aggregate performance is actually -- would be a really misleading indicator, because at any point in time the relative importance of whatever it is, safety versus reliability versus financial measurement, it will be different for each utility. And then as much time as working group will spend on actually saying five percent, 10 percent, 11.5 percent, we will spend all this time and it's not going to be relevant for decision-making. And that's what we will want to have at the end of the day.

MS. BRICKENDEN: Thank you. Patrick?

MR. HOEY: Lisa, Patrick Hoey from Hydro Ottawa.

My experience also is that when weightings do occur, they vary year-to-year, periods of time, based upon the priorities that occur within the companies.

Even the same company will, over a five-year period, have different weightings between markers, so the comparability of one scorecard in one year to the next may not be as simple as people think it would be. It may not be there.

MS. BRICKENDEN: Thank you.

Indy?

MS. BUTANY-DESOUSA: As a follow-on to Patrick's comments, then, it begs the question on the trend analysis. I know you identified upfront that it's simplistic, but it begs the question: Are you looking at the LDC and its trends over the five-year period in aggregate? Are you looking on a year-over-year basis? And then obviously you need to tie back to the particular target, in any event, that's in your extreme right-hand column, and how the utility is doing relative to that target.

MS. BRICKENDEN: Actually that raises another point, Indy.

On our proposed scorecard at this point in time, we have only identified explicit targets where the Board has established a specific target in its Codes.

What are folks' thoughts on what might actually -- or should anything go in there, if it isn't something that the Board has established?

Andrew?

MR. SASSO: Andrew Sasso from Enwin.

I think that everything on a scorecard needs to have a target, and I think that everything -- you know, otherwise

you don't know what you're working towards, and different utilities should be working towards different things.

And I think when that comparison is done between utilities, it will be with reference to the target. No one would expect to have the kind of -- let's say, because Colin walked out -- capital plan targets as Toronto Hydro.

[Laughter]

MR. SASSO: Seriously speaking, you just wouldn't expect that at a lot of other utilities. And that's okay, and that's for the Board and Toronto Hydro and intervenors to work out in Toronto's proceedings, to set that target. They already do it when it comes to rates, and I would expect that they would do it with respect to -- translate that into scorecard criteria for the next five years or whatever, whatever the period is, and I think that's quite legitimate.

And that's why I think it's very important to have LDC-specific targets, because when you come with some sort of aggregate, the target is it going to end up being too low, let's say, for Toronto Hydro, or too high for Enwin, or too high for Enwin and too low for Toronto Hydro.

And I don't think that's helpful for the ratepayers in those actual communities. It may be helpful from some type of aggregate, large-scale comparison purpose, but in terms of actually ensuring that distributors are delivering value for customers in their communities, I just don't think that kind of aggregate targets are all that meaningful.

What will happen over time, of course, through -- as

with anything, is that a general trend will emerge. For the most part, utilities will generally have a pointy target or a 300 target or whatever the metric is. And we'll all get used to what that general expectation is over time, and that will become the informal starting point for discussion during any type of a target-setting process.

So I think there is some efficiency there. I don't think it's going to be chaos forever. I think you grow into it, you develop an expectation, but I would be -- I very much encourage the Board not to establish a universal target for everybody, for those reasons.

MS. BRICKENDEN: Thank you, Andrew.

Jay?

MR. SHEPHERD: Just to follow up on that, Andrew, it sound like you're suggesting -- and I may actually be saying this is a good idea -- that part of the rebasing process should include not just setting the rates for one year, but setting the metric targets for various metrics for the five-year period until next rebasing. Is that -- there is an obvious regulatory burden question and a regulatory cost question associated with that.

MR. SASSO: I think if we're going to do it anyway, the best time do is during cost of service. And I can't think of any better time to do it.

Obviously, a utility -- as I said in my opening comments -- a utility who is on annual IR, this presents an issue. But I think it's no different in some ways than the -- I'm not going to pretend to understand it completely,

but the asset management plan filings. And you're developing a capital plan on a five-year term. You've got an IRM cycle that is, I believe, five years, and you've got custom IR that again, I believe, is designed to be a five-year customized rate-setting plan.

So I think for an awful lot of utilities, that five-year horizon makes sense, and your OM&A is being set essentially having regard to that five-year period. Your capital is being set for that five-year period, essentially.

So then you're tying your outcomes with the money you actually need to achieve the outcomes, which I think is extremely critical.

MS. BRICKENDEN: Thank you, Andrew. Judy, and then Carm.

MS. KWIK: Judy Kwik for the Power Workers' Union. This issue of targets tells me that maybe the financial ratios in here that I use as performance metrics are not appropriate on the scorecard.

Patrick earlier mentioned a corporate scorecard relative to the regulatory scorecard, and this is something I'm sure the shareholders would be very interested in.

But as measures on the regulatory scorecard, I think we need to discuss how that actually fits.

MS. BRICKENDEN: Carm?

MR. ALTOMARE: Going back to -- I'm not sure who brought this up, but the scorecards, and then benchmarking. In my mind, they're not separate, in the sense that when

you're doing the scorecard, you're having to establish targets, and how do you go about establishing those targets? There are several ways.

One of them is benchmarking. For example, how do you compare with comparable utilities in these different areas that you're tracking in the scorecard?

So you would be doing benchmarking to see who's out there, who is comparable and how they're performing. And it would encourage you to discuss with, let's say, these utilities that are doing better than you in the different areas, to see why they're better. What practices do they have? And ultimately see if those practices can be implemented locally.

For example, there are some practices you can implement for collective agreement purposes, but some you can't. So what's the impact on your performance by implementing these -- some people call them best practices, some people call them improved practices. But, in any case, benchmarking is a tool in developing your scorecard, and, more particularly, not just the measures, but also the targets.

And so it's a very important point in the sense that you want to look at your traditional performance and compliment yourself that you're improving. Year over year you see improvement, but when you look at the comparable utilities, you're a poor performer, and it doesn't sit right with the board of directors, at least in Hydro One, because we're being challenged continuously, you know, Is

that target best in class or is that target going to help us achieve best in class five years down the road?

So that's why benchmarking is an important tool. And I know several people around the table are very frightened of benchmarking, but, in essence, benchmarking is a tool that's used in a lot of the service industries in North America and internationally.

So that's how you learn on how others are doing. And, in my mind, the simple principle is stealing from the best. That really is what benchmarking is all about.

I don't think they're separate, but how we work that out I think will be interesting in the working committee.

The other thing I just want to bring up, I know I didn't provide input on the scorecard. In the OM&A cost per customer, I think we need to give consideration to OM&A per asset, and also maybe look at the size of the assets, like the asset management, maybe looking at a cost per kilometre or a cost per asset, not just looking at customer, because I think it may give the wrong message depending on the makeup of the utility.

And a comparison about comparing Toronto to Hydro One, I don't think that would be a worthwhile comparison for the simple reason we're totally different utilities, and I think the OEB has properly identified Hydro One as being much different or unique, and we would be doing comparisons outside of Ontario.

MS. BRICKENDEN: I might check again with Laurie. Are there any questions online? No? Andrew?

MR. SASSO: Just a question, Lisa. Is there any talk about doing comparisons for other utilities outside of Ontario? I don't say that to take away from Hydro One, but is there any thought, not necessarily -- whether it's for benchmarking or scorecarding or target setting or what have you, to saying, Okay, here are other municipally-owned utilities in the United States, what have you, and investor-owned utilities in the United States, but ones of comparable size, comparable service areas or anything.

I'm not saying it as a definitive thing. I know people get freaked out. I'm not saying that this is going to -- you know, but there are Ontario nuances. I'm just curious if that's part of the discussion.

MS. BRICKENDEN: At this point, no, we don't anticipate actually doing jurisdictional comparisons of companies and to establish targets. At this point, we're looking at trying to establish a framework, and we will learn from other jurisdictions best practices in scorecarding and maybe what measures are in place, but not specifically their performance. Do you know what I mean?

MR. SASSO: The reason I raise it is I note -- and I mentioned this with some of my EDA colleagues. Many of us who sent crews down to the east coast during the Sandy storm observed, aside from the storm's effects, infrastructure that was built to very different standards. That is the case in Ontario.

We've done things with a neighbour to the north of us who is in a different country, and we've observed the same

sorts of things in their system. That's a two-million-customer utility that comes over and looks at our system to find out, Wow, these are really leading-edge technologies, you know, things we put in place 15 years ago.

So I just raise it because I think there has been some comment, even I believe in the distribution sector review panel, about the quality of Ontario's infrastructure relative to a lot of other jurisdictions. And to the extent our targets are continually pushing us higher, maybe that's good, but in an era where we're very concerned about rates, there is obviously a trade-off that has to take place.

And maybe when we're looking to compete with international jurisdictions for economic development, and so on, having some sense of whether or not we need reliability to five 9s after the decimal point or whatever, whether that's really a reasonable standard, even if it's the logical outcome of continuous improvement or referring to ourselves within this jurisdiction.

MS. BRICKENDEN: Thank you, Andrew. Judy.

MS. KWIK: Judy Kwik, Power Workers' Union. Can I just repeat the need for willingness-to-pay studies. Thank you.

MS. BRICKENDEN: Thank you, Judy. Are there any other observations or comments, questions? Patrick?

MR. HOEY: Patrick Hoey from Hydro One. Just back to the scorecard elements. I just have one question for Board Staff, and it was on the profitability. You had a

financial statement rate of return on equity and a regulatory rate of return on equity as two different measures.

I guess my question to Board Staff was: What's different between the two of them?

MS. BRICKENDEN: Could I ask perhaps Duncan Skinner to take that question, please?

MR. SKINNER: The utilities asked us to adjust the interest component and adjust the after-tax impact of the difference in interest in the regulatory calculation of ROE.

In the yearbook, we divide the net income reported to us by the equity. The utility said that wasn't fair and wasn't reflective of their performance on a regulatory basis, and that's why we have both.

MS. BRICKENDEN: Thank you, Duncan. Any other comments or questions?

MS. GIRVAN: I had a question - Julie Girvan - for Carm. How do you measure OM&A cost per asset? What does that give you?

MR. ALTOMARE: The concern I had with OM&A per customer is the point that was the raised in Toronto. Like, a customer may be a huge apartment block and that just counts as one, but in their costs to maintain that connection, it costs a lot of money; for example, maintaining underground cables or maintaining several feeders.

So to me, it's questionable why you would go to

dollars per customer. Whereas if you go for dollars per asset, it incorporates all the assets that are required to service customers, and those assets would not only include the stations, but also would include the lines, either overhead or underground or submarine or -- and that would be, in my mind, more indicative of trying to see how much OM&A are we spending on an annual basis to maintaining and operating those assets, as opposed to customer.

And then when you get into the rural business, you could use assets, but to me, if your programs are being managed by some attribute like distance, then OM&A per kilometre for a rural utility would be more indicative. And you could also use it for urban, but we're not there yet.

And that's why, when you look at these denominators, what is better in monitoring your performance.

MR. COWAN: It's Allan Cowan for Hydro One.

I think that's what Jay was referring to, is some of these additional measures that may be required to help or - specific unique characteristics of the various LDCs.

MS. YAMPOLSKY: Elena, PowerStream.

Just coming back to the target definition, I'm looking back at the scorecard. So most of these measures, they already have the targets defined, either by Distribution System Code or by -- essentially, that's already defined.

As for cost performance, I really don't see Board Staff sitting and telling us: Oh, you guys have to be number four in efficiency cost ranking, or you have to

achieve $215 per customer, or for whatever it is.

I honestly think it would be more practical to let utilities define their own target, put it on the scorecard -- just a thought -- and actually measure how the utilities are moving towards the target simply will be more practical.

MS. BRICKENDEN: Thank you. Jay?

MR. SHEPHERD: My understanding of where Andrew was going and I think I agreed -- and maybe you're saying the same thing -- is that on rebasing, a utility could come in with proposals for what their target should be over the IRM period, for example, the five-year period.

And the Board could then assess and say to the utility: We don't think you're being aggressive enough. Or: We think you're being too aggressive, and it's not realistic.

But it would start with a proposal from the utility, where they think they should go with their various cost measures. That makes a lot of sense. You do it internally anyway, right?

MS. YAMPOLSKY: Yes, that's true. I do agree with -- I really don't want this one to be just, you know, additional issue on cost of service application. Is your – I already can see it. Is your target on balanced scorecard appropriate? And spending another half a day on this one.

MR. SHEPHERD: It won't be half a day. That's the issue I was raising with Andrew. It wouldn't, in fact, be half a day. It could be quite complicated, at least at the

beginning, until we start to get a sense of what -- of the sort of standards that make sense.

MS. BRICKENDEN: Andrew? And then Jane.

MR. SASSO: It will add to the process, but it's part of what's happening now anyway. We've had a discussion for at least a year on the topic of regulatory framework, about going to a model that's more about value and less about a cost focus.

And if we're going to focus on value, and we're very much behind that, you have to talk about what you're getting for the money. That's what value is.

So when we get a Board decision and it's knocking us down by a certain amount for OM&A or approving a certain increase to enable capital expenditures, there is something that goes behind that, which is the actual service that's going to flow from the money that's actually being provided.

So I think it's already happening. We're just not very explicit about it in our process, about saying here is what's going to happen. It's often part of the application. It's always part of the submissions, saying: If you give us X amount of money, here is the consequence in terms of the service. Even in a settlement agreement, you have to talk about: Okay, if you're agreeing to less money, here's how you can still manage within that context, and here's the things you'll do and the things you will no longer do.

And all we're now saying is here is the impact on the

target itself. So it is more work. Nobody -- inherently you don't want more work, but the benefit is now you can actually have a more holistic dialogue, I think, during cost of service.

MS. BRICKENDEN: Thank you, Andrew.

Jane?

MS. SCOTT: Similar -- further to what Andrew is saying is if we're moving to a more outcome-focussed approach, that, yes, in the cost of service the focus will be on the scorecard and the outcomes, as opposed to getting down into the details of what we're spending every cent on so that there will be some saving.

To me, it's a shift in focus; it's not adding to the cost of service work.

MR. BAKULEV: To add to the discussion, I'm kind of -- I'm thinking that we have these targets. The question is how we're going to use these targets.

Is it for incentive rewards, or just for comparison?

So we need to think about that. Just to have a target, it's not enough. Just to set this target is not enough. We need to know what's -- further out, what we're going to do with that.

MS. BRICKENDEN: That gets to the Question No. 5 that is up right now:

> "Do existing consequences associated with the proposed measures continue to be appropriate? Why or why not?"

MR. BAKULEV: I guess there is only one consequence

right now. It is with this efficiency ranking, right? Whether we have 0.2, 0.4 or 0.6 percent reduction in cost, what are other consequences? Just lose the license, right? That's another one.

MS. BRICKENDEN: Or a compliance process. Jay?

MR. SHEPHERD: Just responding to Andrew, and one thing I don't think we should miss here is that if rebasing included approval of targets, it allows the Board a more nuanced way of sending messages to the utility.

Right now, all the Board can do is say: Yes, you can spend this much next year. Or: No, you can't; you can spend this much instead. And the Board can make comments, but it can't actually get down into the details of what direction should you be going in.

By allowing some target-setting in that process, it would allow the Board to send a more complex set of messages to the utility, and it might indeed allow the Board to say: We're not going to whack you back as much on your OM&A this year, but here is the target you should be going after, and next time you come in for rebasing we're going to be looking at whether you achieved it.

So it might actually benefit some utilities that have a bigger challenge to address.

MS. BRICKENDEN: Andrew?

MR. SASSO: There are presumably utilities out there who have very low rates, who have very low levels of service or very low levels of investment in their system, and that's a concern and that needs to be addressed.

The punishment -- to your point, Jay -- of having a utility getting knocked financially, it just doesn't work in that context. It's doing the opposite of what you need to do. So I think it becomes very convoluted.

I'm presupposing, probably inappropriately, but I think it would be very difficult as a Board member in crafting a decision to send a message to a utility when service is low but rates are low. And the consequence is that you need a rate -- a further rate increase in order to deal with the problem and the target says -- we're really going into the meaning of section 1.1 of the OEB Act, clause 1 or whatever it is, that talks about performance as opposed to point 2, which is about the financial component.

MS. BRICKENDEN: With the move to the multi-year -- a move or more aligned with a multi-year planning and with the work that is going on right now with Stephen Cain's consultations, I like to think of it as making the commitments in planning, keeping the commitments in executing, and the scorecard will capture or could capture those commitments that the company has made and on which the Board has made -- approved certain approvals into rates, and the scorecard will then be used to demonstrate the achievement and keeping of those commitments.

I don't mean to oversimplify it, but I know that the devil is in the details, but at the same time I'm a little uncomfortable with discussions on targets if it's left -- if people leave the room thinking the targets established on a scorecard on day one are fixed there in cement for

five years. I don't know as a business person -- and, again, I'm going to say like Andrew, maybe I'm speaking out of turn here, but as a business person, I don't know if that is a reasonable proposition to make.

Business doesn't work that way. But once a commitment is made, there is the expectation that you will endeavour to keep that. On an ongoing basis, the scorecard operates as a tool to track that or to monitor that. Judy?

MS. KWIK: Judy Kwik for the Power Workers' Union. Isn't the intent of the scorecard actually to recognize that performance of all these measures is an integrated phenomenon? Rather than trying to set targets on the individual measures or the aggregate scorecard, isn't it to assess performance in an integrated manner?

MS. BRICKENDEN: That's a good point, a more holistic view of --

MS. KWIK: That's what we need. They are related, so you have to look at them together, right?

I think that's a good use of it.

MS. BRICKENDEN: Bill?

MR. HARPER: Bill Harper. I just wanted to sort of -- I'm sure a couple other people in the room here are on -- are participating on Stephen's work group, and I just wanted to reiterate the point that you just made, that one of the issues we're struggling with is that one can put together an asset plan for five years, but to think that asset plan is going to be the same for that -- is going to actually hold for five years is probably a very optimistic

assumption.

How do you allow for legitimate flexibility or a little bit -- changes in asset plan. That's one of the key issues we've actually been struggling with. I just wanted to mention that, because if you think of how this is going to tie into five-year plans for scorecards here, I think it is an issue.

Think of it as a road map, but as you get traffic reports as you're travelling, you maybe have to change your route as you go on your destination. Exactly the same thing with asset management plan. As you get updated information, you may have to change your route as you go towards what may be a broad objective, but how you get there may be different.

MS. BRICKENDEN: Thank you, Bill. Carm?

MR. ALTOMARE: To Judy's question, when you look at the balanced scorecard, there is integration between the different performance areas. And the reason why the balanced scorecard works so well is that some utilities are more focussed on cost, so they're trying to drive their unit cost down.

But if you look at the balanced scorecard, driving the unit cost down superficially will impact on the service to the customer. So it will come across in the service indicators. It will certainly come across in the reliability indicators.

But having said that, it is very important to establish targets for all the different strategic areas and

monitor individually, but realizing that they are integrated, realizing that one has impact on the other.

And a good example is also safety. I use safety as a bellwether metric when I'm comparing to other utilities, because in my mind a utility that does very well in safety is doing very well overall. And that's why, if you're trying to also reduce your unit costs, you may see some implications on your safety. So I hope that helps.

MS. KWIK: Thank you, Carm. That's good.

MS. BRICKENDEN: Thank you. I'll check with Laurie again. For those of you listening, if you do have questions, I remind you you can e-mail them into the rrf@ontarioenergyboard.ca account. Any other thoughts? Andrew?

MR. SASSO: Just to Bill's point, I would fully expect any distributor and I would fully expect the ratepayer groups, and the Board in setting the targets, to develop a sense of dead bands on either end of the various targets, and I would expect that there would be gradations. And I wouldn't expect the dead bands would necessarily be the same for all distributors.

You would appreciate because there is a new foray into a certain issue or area of expenditure that the dead band may need to be a little bit more generous in a particular plan. You know, maybe there's some type of an acquisition or a merger or something like that, and there is a little bit more uncertainty; whereas on some of the other metrics it might be a little bit tighter.

And I would hope and fully expect that Board Staff, in taking any kind of corrective measures associated with that, would -- you know, Board Staff is very good about that kind of thing. They would pick up the phone and they would call the utility and do some initial preliminary work. That's how they operate.

So I think it's -- I think we've got a good regime to put that into, because I think we're good at dealing with those kinds of situations as opposed to jumping right to a compliance proceeding or something, or a financial penalty.

MS. BRICKENDEN: Thank you, Andrew. Judy Simon?

MS. SIMON: Just one comment. I like the direction of dealing with the setting of targets when rebasing and the approval of targets.

I think it might be helpful if there was some choice. If the OEB actually provided some default options, that might be helpful to some utilities and also provide some direction. I think the dead band idea is a good one.

For any setting of the targets, I think we need to figure out what the linkage is between that target setting and what productivity factor and what stretch factors we might set, because we might -- I'm concerned about double counting and making sure that there is some way to separate out -- separate out the different factors, and also want to make sure that the stretch factor and the productivity factor actually is in line with the targets that we're setting.

MS. BRICKENDEN: That's an interesting comment. I

don't know if you can expand on that, Judy. What we've been doing is setting the stretch factor on solely efficiency ranking. So going forward, once we do have a scorecard established, the efficiency ranking could be one item that informs the Board as to an appropriate assignment.

But the overall scorecard, and maybe what commitments have been made on the scorecard, should be another. Is that what you're hinting at?

MS. SIMON: Well some of the -- yes, and some of the measures that are on the list so far do embed some efficiency components, and some of the things that we've discussed, as additions to the measures, may also have an efficiency component. So there is some overlap potentially.

MS. BRICKENDEN: Thank you, Judy.

MR. BAKULEV: Alex Bakulev from Hydro. I think there should be -- convenient to this comment, there should be a linkage between investment plans and the targets. So when you say that, okay, we would like to improve telephone accessibility, but we need to spend an additional 2 million on that, right, Board, are you allowing us to do that or not? If not, then that's the target. If yes, then we have to commit ourselves to this new target.

But then if we do that, we have to have a value for each of the target, so meaning willingness to pay. For this improved service, for improved reliability, for improved safety, public safety, employee safety. So

definitely if we go to set these targets and if you're going to link these targets to the proposed plans, we have to do the surveys on the willingness to pay and mainly for the customers.

MS. BRICKENDEN: Thank you, Alex. Andrew?

MR. SASSO: And I was going to ask this question to Peter offside, but maybe I'll just ask it here.

Is there any thought with these targets and with these scorecards in terms of the policy development process afterwards? And that –- so if we had these scorecards in place a few years ago before, let's say, going into some customer service amendments or Green Energy Act initiatives or low-income processes, building that in -- and maybe it's too premature to deal with, but any thought to how this might inform the Board's policy development process?

MR. HOEY: I think you had it right when you said that might be too premature right now to figure out how that's going to work. As we go through the process and we develop the scorecards and figure out better how they're going to be used –- you've made allusion, for example, in the cost of service and how to deal with them there, versus the annual index -- I think it will be a little clearer how as future, for example, public policy objectives come forward, how and when do they ultimately get incorporated into scorecards, because I think we can count on future public policy objectives in this area.

MS. BRICKENDEN: Good answer, Peter.

Are there any other comments or questions from the

room, or from the e-mail, Laurie? Nothing?

Well, if there aren't any other questions, I want to thank you very much for sharing your thoughts and your ideas and raising some additional issues for us to chew on at the working group.

Our first working group meeting is tomorrow, and I think Brian had indicated earlier on, or Peter, that we will be posting materials in relation to the working group meetings on the Board's website, so you can try to stay in tune with what's being discussed.

And I do hope that you will be hearing from working group members. We will need your input.

So thank you very much for a productive morning. Let's break for lunch, and I suggest we reconvene at -- how's 1:00 o'clock? Thank you very much.

--- Luncheon recess taken at 11:52 a.m.

--- On resuming at 1:02 p.m.

MS. BRICKENDEN: Good afternoon, everyone. I think we can start again. I would like to introduce to you Larry Kaufmann, and I will pass the microphone over to him. Larry.

PRESENTATION BY LARRY KAUFMANN, PH.D.

DR. KAUFMANN: Thank you, Lisa. Everyone can hear me okay from back here? Okay, good.

This presentation this afternoon is going to look at the empirical analysis and the benchmarking more broadly defined. As we have heard from this morning's session, benchmarking plays a significant role in the renewed

regulatory framework, and our empirical work is going to inform the rate adjustment mechanisms under fourth generation IR and the annual IR index, and it may also play a role in terms of a review of custom IR applications.

And more broadly benchmarking, as we've heard this morning, will be used to assess distributor performance and the public's evaluation and facilitation of comparisons among the different companies, the different distributors.

And our work is going to be building on the work that we did for third generation, and in third generation IR, that included -- well, the work there included total cost benchmarking, a TFP study that was used to set the X factor, the productivity factor, and input price trend research. Some of that work was done by Staff, but that was used to inform the choice of the inflation factor and the form of the inflation factor, whether that would be industry-specific or an economy-wide measure of inflation.

This time out, we're advising the Staff on the development of benchmarking models, and those models are going to inform a number of aspects of the renewed regulatory framework, including the inflation factor, the productivity factor again, and again the benchmarking models.

But the difference between third generation and fourth generation and the renewed regulatory framework in general is we're going to be moving to a much more Ontario-specific analyses, deriving these parameters from Ontario-specific information and Ontario-specific analyses.

That includes the inflation factor; also, the productivity factor and the benchmarking models.

And another difference is the benchmarking models in third generation were based on benchmarking of operation, maintenance and administrative cost, OM&A cost. This time out, we're going to be benchmarking total cost. So we're going to include capital cost, as well as OM&A costs, in the benchmarking analyses.

As I'm sure you all know, last month a report was released by the OEB, a concept paper which addresses the empirical analysis, and it was relatively high level, but does go into some detail in terms of the details and the various components of the analyses that would be performed on the inflation factor, the productivity factor and the benchmarking work.

And here in this presentation, I'm just going to walk through the main issues that were discussed in the concept paper, try to flesh those out a little bit, reinforce some of the messages there, and mostly take questions and comments from you. And I consider this kind of the kick-off of the working group process, in a sense, for me in terms of getting feedback from the industry and customer groups and other stakeholders in terms of trying to get as much input as we can, so that we can do the best possible analyses that reflects the concerns and make sure we can be as sensitive as possible to the various data constraints and the concerns of all stakeholders.

For me, that's an important part of what we're doing

today, is to get your feedback so we can begin to assimilate that and make sure that's reflected in our work going forward.

So just a brief summary of how this is going to be organized: Start with the work we did last time, because we are going to be building on that, and then talk a little bit about the data sources that we plan to use in our current analysis, and then go through the three specific empirical components of the rate-making framework. And that's the three empirical pieces of analysis we're going to do, the inflation factor, the TFP analysis, "TFP" for those of you -- I'm sure that's a very familiar term by now. "TFP" stands for total factor productivity -- so the total factor productivity analysis we're going to do, and then the benchmarking analysis. And, again, benchmarking this time is going to be total cost and not OM&A cost.

So third generation incentive regulation, there was a rate adjustment formula for third generation IR and it had three main components. There was an inflation factor, and then there was an X factor that had two components, and those were a productivity factor, which was the same and common for all firms in the industry, and then a productivity stretch factor which was specific to three different cohorts of companies.

The inflation factor was -- the one that was selected by the Board was the GDP IPI, or the implicit price index for gross domestic product, gross domestic product final demand. That's obviously a measure of economy-wide

inflation, a measure of prices for gross domestic product.

We did look at trying to develop more tailored input price inflation factors for the distribution industry, the Ontario sector itself, but there were a number of concerns with the measures that were developed in third generation IR, and one of the biggest concerns was with volatility in measured inflation.

The measures that were developed could vary quite a bit from year to year, and that obviously matters in terms of a plan going forward because, all else equal, you would like to have an inflation factor that's relatively steady and doesn't fluctuate wildly from year to year.

And one of the things we found when looking at the different inflation -- industry-specific inflation factors we examined in third generation IR was that there could be a lot of volatility from year to year under that approach. And because of that, the Board decided not to go with an industry-specific inflation factor but, instead, with an economy-wide factor.

The X factor, the two components for the productivity piece, again, that was an industry-wide trend. So that was the trend in total factor productivity for the industry, and because especially at the time -- and we'll be talking about this quite a bit more, but there were data constraints on the available data in Ontario. And given those constraints, it wasn't really feasible to develop a total factor productivity measure for the Ontario sector. So, instead, we used the US electricity distribution

industry as a proxy for the Ontario industry.

And the work we did looked pretty carefully at the measures of productivity that we did have for the industry in the US versus the industry in Ontario for different time periods, and we found that there was a pretty close correlation in terms of contemporaneous productivity changes and changes and kind of directions or inflection points in the growth of productivity in both the US and Ontario.

And because of that we thought that the US was a pretty good proxy for Ontario, and that's what we suggested and that's what we proposed in our work. And the Board accepted the use of the US electricity distribution industry as a proxy for Ontario. And the productivity factor they selected was based on our study, the average TFP growth from the 1998 through 2006 period, and that number was 0.72 percent. So the approved productivity factor in third generation IR was 0.72.

Some of you may remember there was some debate and discussion about the length of the sample period, and the Board in third generation used the longest sample period that was available to it, which was 18 years. So that's an important thing to remember going forward, because even as we transition to an Ontario-specific analysis, it's very unlikely we're going to have a sample period of that long for fourth generation.

So there was an 18-year sample period that the productivity factor was based on last time. If we go to an

Ontario-specific study, and we're going to, the sample period will be shorter. So that's a factor to keep in mind.

The second component of the X factor was the productivity stretch factor, and again, this was differentiated between three groups of companies in the industry, based on benchmarking analyses which gave us some idea of a relative efficiency. So the idea was that if you're a relatively efficient distributor, then you have less ability to make incremental productivity gains, and that's what the stretch factor is supposed to capture, is your ability to make incremental productivity gains relative to the industry.

So if you're more efficient, then you have less ability to do that, and you should have a lower stretch factor. If you're less efficient, then you have more ability and you should have a higher stretch factor.

So we had developed two benchmarking studies. One was an econometric or statistical analysis of the expected costs of distributors, and then we used that model to compare the difference between companies' expected costs under the model versus their actual cost, and then we also had some statistical confidence intervals around the cost prediction.

And we said that if a company -- if a company's actual cost was below the model's prediction and outside of the confidence interval, then we had some statistical evidence that the company was statistically superior on the

econometric model.

So whenever I use the term "statistically superior," that means that it's outside of the confidence interval around the prediction of the company's cost.

So if a company was -- a distributor was statistically superior on the econometric model and we also had a unit cost model, the unit cost model looked at just the unit OM&A cost, the total OM&A cost, and then divided that by a comprehensive index of its output. And that comprehensive index of output included three output measures: customer numbers, kilowatt-hour deliveries, and circuit kilometres of line.

So those were weighted up, and that was equal to the comprehensive output index. Then those unit cost measures were compared; each company was assigned to one of 11 cohorts or peer groups, and its unit cost was compared to the average unit cost for the other distributors in its assigned peer group.

And the peer groups were based to our statistical analysis of what were the main cost drivers. That had to do with things like size of the company, whether they were on the Canadian Shield or not, extent of undergrounding, things like that.

So there were 11 cohorts, and we looked at each company's unit cost relative to the average unit cost of its cohort, and looked at that difference. And if a company was in the top third, when you rate those differences from top to bottom, if it was below the average

and it was in the top third, then that was also evidence of good cost performance.

So if a company was statistically superior on the econometric model and in the top third on the unit cost model, then those were two indications that it was an efficient company. And if both of those things were true at the same time, then that was the top efficiency cohort; these were the most efficient distributors in the industry based on these two benchmarking analyses, and they got the lowest stretch factor, which in this case the Board decided was 0.2 percent.

And then, conversely, if a company was statistically inferior on the econometric model, which means that its cost was above the cost prediction and outside of the confidence interval, and it was on the bottom third of the unit costs benchmarking analysis, then those are two indications of relative cost inefficiency. So if both of those things were true, then that was considered to be the least efficient cohort of distributors, and they got a higher stretch factor of 0.6.

All other companies essentially were either -- both of those things weren't true simultaneously, and they got a stretch factor of 0.4.

So the benchmarking work was used directly -- and again, this is OM&A benchmarking; it was not total cost benchmarking. But it was used directly in third generation to identify different cohorts of distributors in the industry that are distinguished based on their relatively

efficiency, and the stretch factors were assigned to different cohorts based on that analysis.

So if you were identified as being more efficient, you benefited in a sense by having a lower stretch factor.

Conversely, if you were identified as being less efficient, then you had a higher stretch factor.

And the way that the analysis kind of played out is that if you look at how many companies were assigned to each of these three categories, it was kind of like a bell curve. About two thirds of the companies got a stretch factor of about 0.4 percent; they got the 0.4 percent stretch factor. And then there were about one-sixth of the companies identified as either the efficient cohort or the relatively inefficient cohort, about one-sixth on each, so kind of out on the tails. You know, it had kind of a nice bell-shaped curve, which was kind of intuitively appealing and helped to support the idea this was a reasonable analysis.

Okay? So that's third generation.

Now, it's important to remember that from the outset we wanted to do an Ontario-specific analysis, but we just didn't have enough data from Ontario to do that at the time. And one of the key data constraints had to do with capital. We only had capital data from 2002 through 2006, and so we had a capital stock in 2002 and capital additions from 2002 to 2006. That's all the data we had available to us right now. And that's not -- for reasons I'll talk about a little bit going forward, that's not really enough

data to do -- to get an accurate measure of a company's capital stock.

So because of that, because we were constrained on the capital data, we confined our benchmarking analysis to OM&A costs, and we know that there are problems, potential problems with that. There are always going to be concerns, because a company's OM&A performance can be affected by its capital decisions. We knew that going in. And that's why we decided to have two tests, so that we were only going to assign stretch factors if our analysis was relatively robust, in a sense, if two tests were identifying the company as being efficient or inefficient.

But we were constrained on the capital data, and that did have implications for the analysis we did.

Now, here we are five years later, so there is obviously more data on capital additions, and we've been working with Staff to try to get more historical capital additions data, which would allow us and give us more confidence in doing a total cost analysis and in doing a total factor productivity analysis for the Ontario industry.

So that's been -- that's been and that will be a key focus of our work going forward, is trying to get good capital data and trying to integrate that so that we can develop total factor productivity analyses, total cost analyses, and try to get measures of the productivity factor and the benchmarking models that are specific to the industry.

Okay. Any questions there before I move ahead to the work for fourth generation? Jay?

Q&A/DISCUSSION SESSION:

MR. SHEPHERD: Larry, do you know whether we have any data on how the utilities responded to benchmarking being only on OM&A? Did it result in any change in emphasis within utilities, or do we know?

DR. KAUFMANN: I don't know that yet. We haven't done any sort of analysis. That could be something that might be worth looking into on our report, in our analysis.

MS. KWIK: Judy Kwik for the Power Workers' Union. In Power Workers' Union's submission for the RFE we note that we have seen an increase, a substantial increase, in labour capitalization and overhead capitalization in the mid to late 2000s. This is on an aggregate basis.

DR. KAUFMANN: Yes.

MR. HOEY: Patrick Hoey, Hydro Ottawa. I think you a made a comment a few minutes ago that because the data set in third generation was limited to O&M, we needed these two comparator methods for doing cohorts, meaning the econometric and the peer grouping; is that correct? Is that what you are saying?

DR. KAUFMANN: One of the reasons we wanted to use -- have two tests is because -- yes, because we -- because we only had OM&A data. So there's going to be less confidence in an OM&A benchmark analysis, at least in principle, than with the total cost analysis. That's correct.

MR. HOEY: Okay.

CONTINUED PRESENTATION BY DR. KAUFMANN:

DR. KAUFMANN: Okay. So let's talk about the data. And all of the data we use will be put on the Board's website by Board Staff as that data become available. And at the end of -- by the time that we've done all our work and we have assembled a comprehensive data set and we prepare a report, we will put that data set out, the entire data set, which would include the raw data, all the data transformations, all the business condition variables, all the input prices. Everything would be there, and we would make that available at the time we make our report available. And we've been doing a lot of work to make the presentation of that data as user friendly as possible.

So I don't know how many of you were following the PBR proceeding in Alberta, but the TFP study that was commissioned by the Alberta Utilities Commission, they did put their data set out on -- they made their data set available at the time the report was available, and that's an example of a firm that did that.

Our approach is going to be we're going to make our data that we provide much more user friendly than that. It should be -- it should make our work much more -- we want to make our work very transparent, and we want to have the review and the commenting on the work to be -- we want to facilitate informed commentary and informed review.

So we're putting a lot of emphasis on -- as we assemble this data and present it, we want to make sure that it's in a form that everyone can access and understand

in a very user-friendly way.

So the data that have been posted so far -- and our main data source will be the RRR filings from 2002 through 2011. These are sections -- mostly section 2.15 and 2.17 of the RRR. That includes the cost and a lot of the output data.

But, again, we wanted to look for a longer time series, particularly on capital, and because of that we've gone back and we have accessed some of the old MUDBANK data. And I'm sure a lot of people in this room are familiar with MUDBANK. Some are probably much more familiar than I am. But just a brief review, for those of you that aren't, MUDBANK data were data that were collected by Ontario Hydro, in the previous organization and structure of the industry, when Ontario Hydro had kind of a regulator role for the municipal utilities.

They collected a lot of data from the municipal utilities, and they used that to evaluate suitability of investments and things like that.

The MUDBANK data is the data set that reflects the data collected by Ontario Hydro for the municipal utilities, and Staff has done a lot of work to access some of the old MUDBANK data. And at the time, Ontario Hydro was collecting that data for more than 300 municipal distributors.

Obviously there has been a lot of consolidation and a lot of changes in the industry since then. Staff has done a great job of taking that data and making it compatible

and showing how all the consolidations are compatible with the 77 distributors that exist right now.

We have the MUDBANK data and we are in a position to map that MUDBANK data to the RRR data for the 77 companies that exist now. But we're only interested in the MUDBANK data on the capital additions, and I'll talk more about capital in a second. It's important to try to get as long a series of capital addition data as you can if you want to have an accurate measure of a company's -- distributor's capital stock, and obviously that's critical now, because we're going to be benchmarking capital and we are going to be using capital to develop a TFP trend for the Ontario sector.

Q&A/DISCUSSION SESSION:

MR. McLORG: Larry, hi. Colin McLorg, Toronto Hydro. Just a quick clarifying question. Will the integrated capital data be made available prior to your analysis on it, so that utilities can check for accuracy and omissions and so on?

DR. KAUFMANN: My understanding is the MUDBANK data is available now. What we don't have, though, the MUDBANK data only has capital stocks. So they don't have capital additions, but you can infer capital additions by looking at changes in gross plant and making some assumptions on retirements between those years.

So we don't -- what's available now are the MUDBANK data on capital stocks and capital additions data under the RRR filing. So the pieces are there, but we haven't

assembled those in a consistent and coherent manner right now.

We could do that, but we're probably -- so if you like, we can make that part of the database available sooner rather than later.

MR. McLORG: Well, that's helpful. But with respect particularly to the mapping of the data to the existing set of utilities, will utilities and all stakeholders have a chance to review that for accuracy and completeness prior to the analysis being carried out?

MS. BRICKENDEN: Yes, definitely, Colin. That's why we posted it, and we actually want to take this to the working group and ask the help of the working group to review the information and get a better understanding of how good is it. How well does it produce a continuous trend?

MR. McLORG: Okay, perfect. Thank you.

MS. GRIFFITHS: Sarah Griffiths with PowerStream. Recognizing the 2012 data isn't due until April 30th and the timing that is obviously going to go in the next couple months to the development, is there any potential to use 2012 data just knowing this would all be based -- you know, we're going forward for 2014 and that is a few years' lag time?

DR. KAUFMANN: My understanding is, given the time lines that have been set for making decisions, that that's probably not going to be feasible. We have to have our report in by early April -- sorry, Brian, you may want to

take this.

MR. HEWSON: Sorry, not to pre-empt Larry too much, but I was going to suggest, Sarah, that I think it is something we want to talk to the working group about, whether there is some way to -- I mean, if there is a way to feasibly bring that into the work that Larry is doing, whether it's in the report that's due or after when the Board is considering the process for setting the actual numbers.

DR. KAUFMANN: I can say adding your data is not a really trivial task. A lot can change so...

MR. ALTOMARE: Larry, Carm Altomare, Hydro One. I would like to follow up on Colin's point. I was requested by Lisa to see if we did have the data going back to the '90s, if not to late '80s, and I was really challenged with an answer.

So I believe I passed you to regulatory and they, in essence, passed off to finance. And my understanding, from an e-mail I received from finance, is that they don't have any confidence in that data at all.

So I think for the records we should make that noted, that even though it was being collected by Ontario Hydro 20 years later, or whatever, to go back and use that data, our finance people are not very comfortable with that.

So I thought I should pass that along.

MS. BRICKENDEN: A question of clarification, Carm. We're talking about the Hydro One Distribution equivalent or retail system information; correct?

MR. ALTOMARE: Yes.

MS. BRICKENDEN: Not necessarily the MEU-reported information in the annual reports; it's different.

What we discovered was that the Ontario MUDBANK data surprisingly does not include -- well, not surprisingly. It does not include the Ontario Hydro retail system, and that's the missing puzzle that we've been working with Hydro One to try to get.

And I do not see value in fabricating data. We've had this conversation. So if it's available, it's available, and if it's not, it's not, and the MUDBANK data is what it is. We're not looking to revise it or...

MR. ALTOMARE: I'm happy to hear that, Lisa.

DR. KAUFMANN: Carm, that's kind of the point -- the final two bullets, that's the first of the two bullets below, so that's what we're referring to there, the pre-2002 data the Hydro One itself, as opposed to the munis.

Okay. So that is the MUDBANK data. The MUDBANK data is online, and another piece of data or another source of data that's online are the data on the low-voltage charges that are paid by some distributors, some embedded distributors in the Hydro One system, who don't have certain types of low-voltage assets and instead purchase those -- essentially rent those assets from Hydro One, and pay low-voltage charges. Those low-voltage charges aren't reflected in those distributors' OM&A costs, so it's important to have data on those when we benchmark those distributors.

So that's the purpose of having those data, and those data are posted on the website.

And then there are two other pieces, and I should say that what's also been posted on the website are data for 2000 and 2001, which are similar to the RRR filings, but my understanding is that those aren't exactly RRR filings for those years. But those were data that PWU made available and requested be posted on the site. And with some redactions for privacy, those data are now available, as well. And that happened after I prepared this presentation.

So the two pieces of data that we're still working on and still hoping we can get information on, to get into our data set so that we can have the most complete data that we need to do the analysis, one is the capital additions for Hydro One for the old Ontario Hydro system that -- the distribution system for the old Ontario Hydro company for the '89 through '98, and possibly for the '89 through 2002 period.

And then also the -- some data on smart meters, and the issue here is that during the sample period, between 2002 and 2011, companies swapped out through kind of a rolling process their old accumulation meters for smart meters. And when the old accumulation meters were no longer being used, they were considered stranded and they were taken off the books for the RRR filings.

So what we noticed is that there are these discontinuities, there are these declines in assets as

companies' smart meters come on and as the accumulation meters go off. And the smart meter capital investments are not recorded directly in the RRRs either. There is a different filing and -- my understanding -- a different regulatory process for approving those.

So we know that companies' meters are not disappearing, and if we don't have some data on the meters that are taking the place of the old accumulation meters, it's going to look like companies are making these big capital savings because capital is disappearing just because of a regulatory -- what happened with the meters and the regulatory accounting.

So what we're trying to do is we're trying to get enough information so we can fill in that gap and we can get the smart meter investment for each of the companies as the companies make that investment and as those investments replace the meters reported as stranded and that disappear from the RRR filings.

And Staff is actually working on a data request to the companies, which is going to -- which has a template which will ask the companies to provide that data.

Bill?

MR. HARPER: Bill Harper.

I don't know if you were here this morning, Larry, but one of the utility representatives, when we were talking about benchmarking, raised the issues of utilities that own their own transformers. And this was a practice that started probably back somewhere in the 1990s, actually.

So I was wondering -- I didn't notice this on your list here. We talked about the low-voltage charges, where you had a plan or a formal attempt through your process to acknowledge the fact that, just from a capital perspective, some utilities will have these investments built into their capital additions that you're talking about, and others won't have them at all, sort of thing.

DR. KAUFMANN: Right. That's an important issue for the benchmarking, in particular, when you want to compare companies, the companies that have those high-voltage assets and the ones that don't.

And there are some data in the RRR filings on the extent of that, the number of transformers above different kV levels, and I believe there's some breakdown, too, of assets by type.

So we can use that, and we will look at those as business condition variables in the econometric analysis.

Andrew?

MR. SASSO: Andrew Sasso, Enwin.

I don't know -- it's not clear to me, so I take it that the capital additions, that means net of capital contributions, and I'm just curious what impact that has, if anything, in terms of what kind of picture this paints of utilities that either had changes in capital contributions over time or maybe have generally high capital contributions versus low capital contributions.

DR. KAUFMANN: Capital contributions are out of the analysis, because they're not regulated under IR.

So in that sense, they're not -- that's not a relevant IR cost, so it shouldn't be in the TFP trend.

Whether it should be in the capital levels that are used for benchmarking, I suppose is an open issue, a debatable issue. If we did that, if we included the capital contributions for benchmarking, didn't include them for TFP, then we would have to have two capital stocks, two types of capital stocks. We would have to kind of roll those back in.

So I suppose that could be something we could discuss in the working group meeting, whether it's worth doing that, whether that's a significant enough issue.

MS. McLORG: Lori McLorg, Veridian.

One other differentiation on -- I just thought of it when Andrew was talking, not only on things like transformer station ownership but how the utility was actually formed.

For example, our service area is non-contiguous. We've been formed by the amalgamation of many utilities, so as a result, the number of actual distribution stations that we have per customer is higher than, say, another utility that's a small, compact service area.

So would capital additions look odd for us, or high, compared to others, but that's not necessarily an inefficiency; it's just history.

DR. KAUFMANN: That is a variable that we are going to consider in our work, is whether or not companies have contiguous or non-contiguous areas.

As you probably know, that's an issue that's been raised by the distribution task force, or -- they just issued a report a few weeks ago. That was one of the things they raised in terms of the structure of the industry and the impact on industry cost.

So we will be considering that as a business condition variable in the benchmarking.

MS. MCLORG: But in consideration, that's what I'm asking, is -- because it's historic, and not necessarily that had you been green-fielding this or the utility had been developed differently, those costs and those capital additions are there and they can't be changed because of the fact that we can't move the service areas together.

So what I'm trying to understand is: Would it be taken into consideration, and what could, on the service, look as an inefficiency be explained by that variable and removed?

DR. KAUFMANN: Well, yes. I mean, the way it would work is we would include that variable in the cost model, and if it shows, if having a non-contiguous service territory is shown to have a statistically significant impact on the company's cost and to increase the company's cost because of that, then we would keep that variable in the model.

And then for companies like yours that had that, we would -- your cost prediction would reflect the fact that you had a non-contiguous service territory. So your cost prediction would be higher.

Lisa?

MS. BRICKENDEN: I don't have a question, but I wanted to remind the participants listening in that they may send in any written questions that they have for Larry to the RRF e-mail account, and we have Laurie monitoring that. Thank you.

DR. KAUFMANN: Okay. So any final questions on the data issues? Okay.

Well, data, if there have been data challenges from the beginning, those are the challenges that we see right now and -- but we're going to do our best and try to develop -- you know, use the available information again to develop a TFP trend for the industry and to develop the best possible benchmarking models for the industry, total cost benchmarking.

So let's talk about the inflation factor. In its October Board report for the RRF, the Board said that it will adopt a more industry-specific inflation factor for fourth gen IR, and also for the annual IR rate-making formula. An industry-specific inflation factor is one that is constructed as a weighted average of the growth in specific input price sub-indexes. These are indexes of price change for individual inputs or individual classes of inputs.

So, for example, you can have industry input price inflation as being a weighted average of the growth in prices for labour, prices for non-labour, O&M inputs, and for the growth in capital. And if capital is about 60

percent of your cost and your OM&A costs are split 50-50 between labour and non-labour, then you would have something like this as an industry-specific input price inflation factor, apply a 20 percent weight to the growth a labour price index, 20 percent weight to the growth in some proxy for the inflation and non-labour OM&A prices, and 60 percent to the growth in the capital price index.

MR. SHEPHERD: Can I ask a question about that, Larry?

DR. KAUFMANN: Sure.

MR. SHEPHERD: The -- Jay Shepherd, sorry. For utilities, labour is a big factor in capital, as well. I'm wondering how you factor the two together?

DR. KAUFMANN: I'll be talking about the capital price index in just a second. There are several pieces to it, but you're absolutely right that will show up as a piece of the price index for capital. Any other questions? Okay.

In its October RRF report, the Board specified various criteria for the inflation factor to satisfy, and one is to use data that are readily available from the public, from public sources and their objective. So they come from respected sources like StatsCan.

For labour prices, the report said that inflation in labour prices would be indexed by a generic and off-the-shelf labour price index, so not something that's specific to the Ontario electricity distribution sector.

And inflation in non-labour prices should be indexed by something that is as specific as possible to the Ontario distribution sector.

So those were the criteria that were laid out in the report. Going forward for the working group, I think the two main issues we have to consider with respect to the inflation factor is: One, what are the best choices for the sub-indexes? That's mostly what picking an inflation factor -- choosing a reasonable inflation factor for an inflation index would be, getting the best possible measures for labour, non-labour, O&M and capital price sub-indexes.

And then second, because of the concerns with volatility with the industry-specific measures that were developed in third generation, we're going to be looking at options to mitigate the volatility in whatever inflation measure might be proposed. So, for example, in each year the inflation factor that applies in the rate adjustment mechanism could be computed as a three-year moving average of the inflation that's computed under the formula where it's a weighted average of the different sub-indexes.

So it wouldn't just be the inflation in that year. It would be the average inflation over the last three years; just one possibility.

The second piece is the productivity factor, and high level basics on total factor productivity, that's defined to be relationship between output quantity and input quantity. So you could have a total factor productivity level index which is equal to the level of output quantity divided by the level of input quantity, or you could look at the growth in TFP. And that would be equal to the

changes in output quantity minus the changes in input quantity.

Obviously, in an incentive framework, what's relevant is the growth in total factor productivity. In general, there are two main approaches that can be used to estimate total factor productivity growth. One is an indexing method, and all an index is is a way to aggregate a different type of information into a comprehensive measure.

So here, with productivity, we would be talking about aggregating different outputs into a comprehensive output measure or different inputs into a comprehensive input measure.

So that's one approach, and, in fact, that's by far the most common approach that's used. But you can also use econometric or statistical methods to project total factor productivity growth going forward, and I'm going to talk a little bit about those two approaches and the pros and cons of each in the next few slides.

Let's start with the indexing approach, because that's what we did in third generation and that is the most common approach. An indexing method would again compute comprehensive measures of output quantities and input quantities, and then the change in TFP would be equal to the change in the output quantities minus the change in the input quantities.

And output quantity would be a weighted average of billing determinants. So that's the right -- those are the right outputs to select in a price cap indexing

application. So the main billing determinants for distributors would be customer numbers, kilowatt-hour deliveries and peak demand, kilowatt demand, to the extent that's billed.

Now, in theory, when you compute a comprehensive output quantity and you weigh each of these three outputs by something to come up with an overall measure, in theory, the right way to weight these three outputs are by the share of each in distribution revenues.

So you would look at the total amount of, say, your distributor's revenues that you collect from customer charges, from monthly charges per customer, you look at the revenues you collect from kilowatt-hour deliveries and you would look at the revenues you collect from peak demand charges, and then you would look at the share of your overall revenues associated by each, and those shares would be the shares that you apply to the different outputs.

So that's theoretically the -- that's what theory says should be the approach you use, but unfortunately that data is very difficult -- I mean, you have it, distributors have it, but it's typically not provided to the regulator, and it would be a laborious exercise to ask for that.

So in practice, because those data typically aren't available, the proxy that's used most often is, instead of using revenue shares, to estimate cost elasticities. So there you're not looking at the impact of different outputs on a company's revenue. Instead, what a cost elasticity tells you, it is an estimate of how much a change in cost

or change in output impacts a company's cost.

So we would get estimates. What's done is to get estimates of those cost elasticities for the three outputs, and then scale them so they're expressed as shares of overall cost elasticity so they all add up to one.

So, in other words, let's just say for customer numbers, kilowatt hours, deliveries and kilowatt demand, we found the cost elasticities were 0.9 -- no, let's say 0.7, 0.2 and 0.1 for those three. Let's make it a little more interesting. Let's say 0.7 and 0.2 and 0.05.

What you would do, then, is the weight that would apply to customer numbers would be 0.7 divided by 0.7, 0.2 plus 0.05, and then similarly for the other two outputs, as well.

So that's the approach we used in third-generation IR, and that's the approach we intend to use in fourth generation, as well.

Andrew?

MR. SASSO: Andrew Sasso, Enwin.

So how does customer mix play into this, if at all? Because I guess one would expect different customer mixes, as opposed to the customer numbers as a whole, to have a fairly big impact.

DR. KAUFMANN: We always look at that and we always test for kilowatt-hour deliveries to different -- for customer numbers, it's very difficult to identify kind of significant impacts on number of industrial customers, because they tend to be so small.

Basically, your customer number overall is going to be overwhelmingly driven by your residential customers, but if you look at how kilowatt-hour deliveries are broken down between different groups, between residential, commercial and industrial customers, and if you have each of those three as being separate outputs, then you can test to see whether each of those has statistically significant and identifiable –- identifiably statistically significant impacts on costs. And if they are showing up as statistically significant cost drivers, then we use those. We decompose the kilowatt-hour deliveries into different components to different customer groups.

But if there is no statistically relationship, then we don't.

MR. SASSO: Do you do that on an LDC-by-LDC basis to do that check, or is that on an aggregate basis?

DR. KAUFMANN: It's on an industry basis.

MR. SASSO: So a utility like Enwin, which gets 55 percent of its revenue -- and since we do cost allocation properly, 55 percent of the cost is residential, compared to, perhaps, PowerStream, where I would think it would be, like, 98 percent residential or something on a revenue basis, or some huge percentage -- whatever it is -- or is everybody just about the same?

I'm just surprised that you could do it on an industry basis, that there would be enough commonality in terms of what it means to each utility.

DR. KAUFMANN: You want a certain variability in the

data so that you can get good estimates, so that's not necessarily problematic.

All it's showing you is an impact of a one percent unit, so it's not so much -- if we were to make a prediction for your cost, it would reflect the impact of your volume mix, your volume mix and your output mix, so that would be reflected.

But what it's really showing you is the impact of a one percent change of each of those different outputs on any distributor's cost, if that makes sense.

And to look at that and to get that estimate, you have to look at the whole industry. We're not going to have enough data, and it would be incredibly expensive and time-consuming to try to come up with company-by-company estimates. And it probably wouldn't be a worthwhile exercise, anyway.

MR. SASSO: Last clarification, just because I'm trying to understand it.

So that would be for this abstract, typical -- you're creating -- for lawyers, we would call it the reasonable person. You're inventing a construct, called sort of the typical LDC, and then you're comparing against that and -- is that --

DR. KAUFMANN: All we're really identifying are function -- parameters of a cost function. If you want to get very technical about it, that's what we're doing.

We're estimating -- the assumption, if you want to say that, is that there is kind of an underlying technology for

the industry, and all distributors share that technology.

What we're doing is we're identifying the parameters of that technology, and we're saying that those parameters apply just as well to Enwin as they do to Enersource, to Toronto Hydro, you name it, but what's going to differ is the mix of outputs that you provide relative to others.

So the parameters don't change, but when you would make a prediction for your cost, you would want to control for the difference in your output mix, and we would do that by using your specific outputs to generate a cost prediction for you.

MR. SASSO: So you're saying that if Enwin adds another customer or if Enwin adds 100 more customers, the cost is projected to be a certain amount based on adding 100 customers, for example, just picking one of these factors?

DR. KAUFMANN: Yes. I -- the change of your cost would be projected by the change in those customers, the percentage change, multiplied by the elasticity.

MR. SASSO: Right, but if our current customer mix -- and I don't know if this is true or not, but if our current customer mix is a predictor of our future customer mix, then for every, let's say, 100 new customers that get added in our service area, one of those might be a large user, whereas Essex Power Lines, because they have no large users, for every 100 customers that they add, none will be a large user.

So the cost won't change in the same way for every 100

customers we each add, but that's okay because it all gets evened out, is what you're saying?

DR. KAUFMANN: No. We wouldn't just identify -- we would never just focus just on those 100 customers, because that's not the only thing that changes.

There are a number of variables in the cost model; there would be customers, there would be kilowatt-hours. So we would look at -- when we look at what's changing between period one and period two, we would look at all the cost driver variables. To come up with a good prediction, you have to look at everything. If your customer mix -- if you have a more industry-intensive sort of customer base and that's what's increasing, then your customer change might be the same as another company but your kilowatt-hour change will be bigger. And we would factor that in, as well.

So the prediction would pick up both of those things. It would pick it up implicitly, because you're adding customers that are bigger. So it would be reflected there.

Colin?

MR. McLORG: Hi, Larry. I have several questions, so I'll ask you and the audience to bear with me a little bit.

Just to begin with, I gathered from what you just said that when you did this regression to estimate the elasticities, you used all the cost drivers; is that correct? Or did you just regress cost against these three variables that we see on the screen?

DR. KAUFMANN: We used all the cost drivers.

MR. McLORG: I see.

With respect to kilowatt-hour deliveries, was it your theory that delivery utility costs change marginally with marginal changes in kilowatt-hour deliveries?

DR. KAUFMANN: It's not a theory; it's just something we test empirically. We see if there's any empirical support for it.

MR. McLORG: Because most utilities, I think, in the room would say that if any given customer or group of customers takes 10 percent fewer kilowatt-hours in a month or 10 percent more kilowatt-hours in a month, our costs don't change at all, except perhaps with respect to losses, which aren't reflected in our costs that you're recording, anyway.

DR. KAUFMANN: I would say two things about that.

First, you're talking about a very short-run analysis. I mean, you're talking a month-to-month sort of perspective. This is supposed to be a long-run sort of analysis.

So month in, month out, if you're serving more kilowatt-hours from a given system, you would think that there would be more wear and tear on your transformers, as opposed to a company that has less.

So that's what we're trying to pick up, in a sense, is the long-run effect, as opposed to the fluctuations from month to month. That's kind of in theory.

But in practice, one problem with -- we know that the kilowatt-hour variable to some extent picks up peak demand,

because the peak demand data tend not to be as good. So to some extent, it's picking up the peak demand variable as opposed to kilowatt-hours. Obviously, those two can differ from company to company based on load factor, but there is kind of a little bit of simultaneity between those two variables.

MR. McLORG: To what degree would you say there is co-linearity between these variables? For instance, the kilowatt-hour deliveries would be highly correlated with customer numbers, over the long run, as you say?

DR. KAUFMANN: Well, there's some, obviously. There's some, but this is picking up the independent impact of that. And depending on your customer mix, particularly if you look at -- and that's one of the benefits of having a very diverse sample in Ontario. You're going to have companies that have -- you're going to see a lot of difference in kilowatt-hours per customer. And if you have that, then that's going to give you more confidence that you're going to be able to identify a statistically significant impact for kilowatts as distinct from customers, if you had variation in that, in the kilowatt per customer metric, which we do have here.

So yes, there is some co-linearity, but if you have a lot of diversity in that relationship, then it makes it more likely you can identify statistically significant, distinct impacts for both of those outputs.

MR. McLORG: Probably I'll take up the econometric discussion with you in the working group without burdening

this discussion.

My last question is: How is it possible to square this measurement of output quantity with the fact that, as a condition of licence, utilities in Ontario are required to reduce kilowatt-hour deliveries and kilowatt demand? That's a condition of licence for us.

So it appears to me that if there's a policy direction from the province which has been embodied in conditions of licence issued by this Board to the effect that utilities are required and have specific targets to reduce their output as it's measured by this methodology, how is it possible to square that requirement with the requirement to increase productivity?

DR. KAUFMANN: Well, this is -- all we're really doing at this point is we're talking about measuring productivity, and what I'm saying is that particularly, I think, given there is that requirement, you want to make sure that kilowatt hours are reflected in the output measure, because this is something that's a condition and it's something that's a real experience in your industry.

And if that's true, then if kilowatt hours are going down relative to history, that would be reflected in lower productivity.

MR. McLORG: Exactly.

DR. KAUFMANN: That's fine. All we're trying to do is come up with the best possible measure of -- I mean, at this point, all we're really talking about is coming up with the best and most accurate measure of what

productivity actually is in the sector, but that doesn't mean -- so that's our mission, but in terms of actually increasing your productivity, you can still increase productivity on the cost side, and I'm sure that's what the Board would argue and the government would argue is what's intended by that sort of policy.

MR. McLORG: All right. We'll take this up in submissions. Thank you.

DR. KAUFMANN: Jay.

MR. SHEPHERD: I'm quite sure this is going to be a stupid question, but I'll ask it anyway. If the theoretically correct way to weight the output quantities is by revenue share, I don't understand why cost elasticity is a good proxy.

It seems to me that assumes there is some connection between the actual revenues that utilities get for each of these categories relative to costs, and I think that my understanding certainly is that nobody believes that's true, that in fact revenue shares are based a little bit on rate design and how classes are structured, and things like that, and historical anomalies and not as much -- actual revenues, and not as much on cost drivers.

DR. KAUFMANN: I agree with that. It's not a perfect proxy. This could be something we could take up in the working group if anybody has any better ideas on how we can weight these outputs. We're not going to have the revenue share date. The cost elasticity data again is what we used in third generation. It has been used numerous times.

It's not perfect.

MR. SHEPHERD: And then the follow-up to that is the Board is, in parallel with this, looking at increased revenue decoupling which would presumably change the revenue shares. How do you factor that in?

DR. KAUFMANN: If there is revenue decoupling, then that would suggest cost elasticity shares are appropriate, because then -- this is a technical, point and we can deal with this in the working group, but if you have revenue decoupling then -- full revenue decoupling, then the cost elasticity shares are in fact the correct ones to use.

You're picking up the revenue impact through the decoupling mechanism, so you don't need to pick it up through the rate adjustment mechanism, as well. If you did, there would be double counting. Yes.

MS. MCLORG: When Jay had those questions about weighting and what was to be used to weight the outputs, I'm not on the working group, so I'm wondering. Is part of the working group's mandate to determine what are the proper outputs quantities, what are the proper outputs, or is that already something that's done?

DR. KAUFMANN: The working group can weigh in on that; that's fine. But, in theory, the right outputs to use for a price cap formulation are the billing determinants.

MS. MCLORG: So that means the other things that were going to be measured on the scorecard even during -- when we come back -- say the premise was we set a scorecard and we come back in and say, How did we do on our scorecard?

In between, we're measured on something different, that is this, as output, but these other things, reliability, for example, there is a cost to reliability, but that on this basis we're not measured on it between there or on our productivity? There is no correlation? There is no meshing of these?

DR. KAUFMANN: It matters in terms of costs, but think about it this way. Right now your revenues don't depend directly on reliability. If you provide more reliability, you don't get a price increase because of that. You don't get a price increase if your reliability goes down.

There is no link right now between the reliability you provide and the prices you charge, and because of that it's not appropriate to use reliability as an output that's used to adjust your prices. That's the basic intuition.

MR. SHEPHERD: Sorry, I don't think that's true at all, Larry. I think in fact when a utility comes out with a capital plan that's intended to increase their reliability, they get higher rates, and that's why they have higher reliability, and vice versa.

DR. KAUFMANN: It's reflected in their cost.

MR. SHEPHERD: Which drives up their prices.

DR. KAUFMANN: The issue is: How do they recover those prices? They don't recover the prices through a charge for reliability. They recover those prices through higher charges.

MR. SHEPHERD: True, true.

DR. KAUFMANN: And that's the issue. I'm not saying

there is no link. If it impacts your costs, then it can impact your prices. The real issue is how you recover those cost increases.

Those are your outputs. If you're not charging for something, it's not, technically speaking, an output that you're providing to your customers in terms of something you're charging.

MS. MCLORG: For productivity purposes, but the ability to deliver on the scorecard during the IRM period is tied to not just productivity, but it is tied to those costs of being able to deliver those things. I'm still struggling with that a little bit.

DR. KAUFMANN: To the extent there are costs associated with reliability and that's an overall objective, then that would be reflected on cost side, and then that would be reflected -- as costs go up, that means inputs go up.

You're installing more capital, whatever, and if inputs go up, then productivity goes down; productivity goes down means the X factor goes down, which means prices go up.

MR. HARPER: Larry, I think what people are struggling with, maybe it's the fact that -- the view that what you deliver is directly reflected in what your billing determinants are. That's what the struggle is that Lori was struggling with and I think Jay was struggling with, is the fact that not -- your billing determinants are what you bill on. It is because it's measurable to some extent and

you can actually bill a quantity on it, but it may not be reflective of what you view as being the outputs of the industry are, I guess, in terms of -- you know, and I guess -- and there is an unfortunate disconnect between there, because you don't bill on -- you don't bill on the number of seconds during a month for which you had service provided as opposed to didn't have service provided.

If you did, that would be a measure of reliability, but we don't bill on that.

DR. KAUFMANN: That's right. Reliability is implicit. It's an implicit thing that you're providing your customers. It's not an explicit outcome, and that would be true under cost of service regulation, as well. If you're only regulated under cost of service and you wanted to -- and you wanted to have a project -- I mean, you wanted to increase your reliability, there are costs associated with it. What would you do?

There would be costs. You would recover those costs through higher prices for the output you charge, customer charges, volumes and peak demand. So that's the issue.

MR. STEPHENSON: Larry, Richard Stephenson. That's only true because you're choosing to make it that way. I mean, you've just defined away the issue. If we had a system where the LDC paid people for non-delivery, then it would be a cost and it would be something you could measure.

There are systems that do that. One of the things we've been saying for a long time is you've got to get

really serious about integrating reliability with rate making, and, I mean, the fact that we haven't done it historically doesn't mean that it's not available. It's just that we haven't chosen to do it.

DR. KAUFMANN: Here's the way to think about this, and this is -- I think we've gone a little too deep in the weeds on this, but maybe we can talk about it more in the working group.

The way to think about this is if you want to recover the cost of a reliability project, you want to fully recover those costs, should you have a reliability input or reliability as a measure of the output in your output index if you're not in fact charging for a reliability. If the answer to that is yes, if you stick something in the output index which shows that it's growing, when it's not something you're billing for, then that's going to show -- I mean, let's say that reliability goes up because of this. That's going to show that productivity is increasing because of this.

And that's not actually true, because that's not something that's reflected directly in your revenue. You're not recovering revenue from that extra output that you're providing.

So if you include reliability as an output, then you're going to have more productivity growth than actually is being measured. So if you want to fully recover those costs and you're not billing for reliability, then you should not have reliability as an output. That's the

issue.

So it's just that's the way the math works out. We can talk about this more, but really, if you kind of become comfortable with the math, you can see that that's -- it might be counterintuitive, but that's the way it is.

Okay? Well, let's move on, and let's talk about input quantity.

CONTINUED PRESENTATION BY DR. KAUFMANN:

The input quantity is a weighted average of two classes of inputs: the OM&A inputs and the capital inputs. And there's a very basic sort of formula, which relates -- basically the cost is going to be equal to -- the cost of an input is equal to the quantities of the input that you procure and the price per unit of input. So because of that, the changes in expenditure are going to be equal to the changes in -- the changes in total inputs procured plus the changes in the prices. You just kind of rearrange the math there, and what you can see is that the changes in input quantity can be measured as the changes in expenditure minus the change in the input price index.

So in other words, what you're basically doing is you're looking at total expenditure on an input, you're looking at what percentage of -- what fraction of that expenditure was due to input price inflation, and the difference would be equal to the quantities of the inputs that you purchased.

So let's say your input -- your OM&A spending goes up by four percent from last year. If your prices for labour

and overall inputs grew by three percent, then that would mean, according to this math, four percent minus three percent equals one percent, so you have a one percent increase in the quantity of OM&A inputs.

So that's a way of accounting for input quantity using input price data and expenditure data. And that's the way that we measure OM&A input quantities; we measure it directly as the change in expenditure over time minus the change in input prices over the same period.

And the input price indexes that we use are the same that would be used for the inflation factor. So we would - that would be kind of a byproduct. The input prices that we need to compute the input quantity index for OM&A would be a byproduct of the work we're doing on the inflation factor, and vice versa.

So that's relatively straightforward. Capital is a little more complicated, and this gets into the issue of trying to use capital additions as much as possible and to go back -- the reason for our interest in the MUDBANK data and to rely on capital additions before 2002.

And the reason is that any time you're doing a productivity study, the capital quantity always begins with what is called a benchmark capital. So this is the value of net plant in a given year. And you want that value of net plant to be as far from the current day as you can possibly make it. Why is that?

Well, we know that net plant -- the value of a net plant that you report in a given year is going to depend a

lot on the vintage of your plant. If you just installed a big transformer last year, that's going to have a big impact on your net plant value because that's a relatively expensive and recent addition, as opposed to investments that you may have made 30, 40 years ago. Just because there is inflation over time and the value of assets this year is higher than assets in previous years, the vintage of what's reflected in your benchmark year, in any given year, matters enormously to what that value is.

So because of that, we want that value to be pushed back as far as we can. And we want to use -- instead of that, we want to use capital additions, add the capital additions to that value and build up the capital stock over time, because we have a lot of confidence in the value. We know what those capital additions are in any given year –- I mean, if we have that data, then we have confidence that those are good data, and we can also get information on what the asset prices were associated with each of those, each of those increments of capital additions.

So we can deflate the capital additions as it's added, if we rely on capital additions instead of a benchmark year. If we want to control for differences in benchmarks across companies, we need to know the -- what the vintage of capital is for distributor A versus distributor B this year, and we don't know that. We're never going to know that. So the way to minimize the impact of that is to push back the benchmark year as far as we can, and instead use capital additions and add those to the benchmark year to

build up the capital stock.

If we look at the formula we have here, that's what this shows. The XKT, that's the capital quantity in a given year T, and that is going to be interest -- actually there is a typo here. This should be -- one minus the -- times XK, this should be T minus 1. So in other words, you would look at -- what you would do is you would look at the capital stock from the last year, eliminate -- reduce the amount of that capital stock by the amount that it depreciated in that year. D is the depreciation rate. So your capital is equal to capital from last year minus depreciation of last year's capital, plus the value -- VI is the value of capital additions in year T, and then you would divide those capital editions by WKAT here, is an asset price index.

So what we're doing here is we're actually building up. We're looking at last year's capital, looking at what it's depreciated, and then we're adding to it this year's capital additions. And because we want this to be a capital stock, so we don't want it to be impacted by inflation in capital asset prices over time, each year we're going to deflate capital additions by a price index for capital in that year.

So this is the basic perpetual inventory equation, and this is what we want to do. We want to rely on as -- to the greatest extent possible, when we build up capital values that we use for TFP or for benchmarking, we want those values to be based on this VI number here, the

capital additions, and not this XKT minus 1. We want to push that back as far as we can.

It looks like, given the data availability in Ontario, the farthest we can push back the capital benchmark year would be 1989. That's as far back as the data allows us to go here, and that's our rationale for the use of the MUDBANK data. If we use MUDBANK, we can push the capital benchmark year back to '89 and rely on capital additions since '89 to come up with capital input measures for the sample period from '89 through 2001, and then from 2002 through 2011.

That would be -- the alternative would be not -- if we don't use the MUDBANK data, then our benchmark year would be 2002. So again, that's putting much more emphasis -- because that's when the RRR data began. I suppose there is a possibility that if 2000 and 2011 data work out, possibly 2000 could be our benchmark year, as well, but even so, that's much more distant -- much closer to the current time than 1989.

So again, this is possibly a subtle point, but it's important, if you want to come up with an accurate TFP measure and accurate capital stocks for different companies, to not rely on a benchmark year to the greatest extent that you can, and instead rely on capital additions.

Q&A/DISCUSSION SESSION:

MS. McLORG: Lori McLorg, Veridian.

Is this type of calculation done for every type of asset class? So for example, it's done for distribution

stations, it's done for computer equipment, because depreciation rates would change, and so -- or is it just done on overall capital?

DR. KAUFMANN: It's done on overall capital, and we would have an overall depreciation rate. So the depreciation would reflect the entire asset mix, and then the capital additions would be all capital additions.

MS. MCLORG: And this is done for the industry as a whole?

DR. KAUFMANN: This is done company by company.

MS. MCLORG: Company by company?

DR. KAUFMANN: Right, and then we aggregate out for the industry.

MS. MCLORG: So it doesn't take -- how do you get the depreciation rate per company?

DR. KAUFMANN: We will talk about that. There are ways to do that. You can look at regulatory depreciation. You can look at a number of studies of economic depreciation in the economic literature. You can look at depreciation rates that are used by statistical agencies in the US and Canada and other parts of the world.

MS. MCLORG: If you're doing company by company, wouldn't you look at their rates?

DR. KAUFMANN: Again, this is an economic depreciation rate, so, you know, it's supposed to reflect the economic depreciation.

MS. MCLORG: Which is different from the accounting depreciation.

DR. KAUFMANN: It could be different from the regulatory depreciation. You can do regulatory depreciation, as well. It's much more complicated, and you need a lot more data to do it well.

MS. MCLORG: Is economic depreciation supposed to be a driver when you need to replace it really versus book depreciation? Is that why it's used?

DR. KAUFMANN: Technically what it is is it's a measure of just how -- the underlying loss in productive value from the asset.

MS. MCLORG: So it would have to be industry specific, because that would vary.

DR. KAUFMANN: It is industry specific. So this would be a measure of depreciation for the electricity distribution industry, obviously.

MS. MCLORG: Again, so a utility's mix of assets, some utility that has a severe need -- I don't know exactly, but they're not always the same over periods of time for things like computer investment, which is very different from regular distribution assets.

DR. KAUFMANN: Right.

MS. MCLORG: So those kind of variabilities would still be in there, because you're using a generic economic depreciation?

DR. KAUFMANN: To the extent those asset mixes differ from company to company, yes, that could be an issue. Again, if we had -- what you're suggesting is a better approach, but you need a lot more information on specific

input prices for different asset classes.

MS. MCLORG: Just highlighting what is a mix of -- when you say that it's utility specific, there are other elements in there that are not.

DR. KAUFMANN: That's right. If there are differences in the change in asset mix from company to company, then that could be an issue. Carm?

MR. ALTOMARE: I would like to ask a question to yourself, Larry, or maybe throw it out to the floor, because it's been a while since I looked at accounting definitions, and that. Is there a difference between capital betterments and capital additions?

DR. KAUFMANN: Capital retirements, sorry?

MR. ALTOMARE: No. What I'm saying is year after year utilities do betterments, as well, for example, either relocating a line because of a highway requiring us to move, or let's say we're improving a line for whatever reasons. We consider that betterment capital.

DR. KAUFMANN: That would be reflected as a capital expenditure.

MR. ALTOMARE: And would be capital additions?

DR. KAUFMANN: Yes. We would record it that way.

MR. ALTOMARE: Thanks.

DR. KAUFMANN: Bill.

MR. HARPER: I don't think you need to go into an explanation now, but maybe tomorrow as part of -- I'm struggling a little bit, and maybe it is the same as Lori was, the purpose for putting depreciation in this, and

maybe we can talk about this in more detail tomorrow, because if I installed a transformer station 20 years ago, its depreciation in terms of how much you can -- you know, what it could supply then versus what it can supply 20 years later may only have gone down by 5 percent, whereas the age -- you know, it's still able to transform the same amount of power, even though, from an accounting perspective, it has depreciated.

So I guess, as I said, unless it's a short answer, I think I need at some point have a better understanding of why we're depreciating it within this formula here. That's all.

DR. KAUFMANN: We're depreciating in the formula because the assets really do depreciate, and it's a question of just what that rate is, and that is going to depend on the asset mix. It's not going to be a huge number, in general.

If you look at the overall asset mix for distributors, it could be 3 or 4 percent, 5 percent, something like that, and that's going to be weighted more towards -- obviously some things like computer systems and meters are going to depreciate faster than the poles and transformers. That's reflected in the number.

That would be reflected in -- if we're looking at regulatory rates or if we're looking at estimates from the literature, that would be reflected in what's estimated. Jay.

MR. SHEPHERD: You said this depreciation rate is the

estimate of annual loss in productive capacity.

DR. KAUFMANN: Yes.

MR. SHEPHERD: You're using a straight-line type of approach?

DR. KAUFMANN: We're using what's called a geometric decay. Getting into the details of that, let's save it for the working group.

MR. SHEPHERD: The reason I ask is because utility assets tend to not depreciate on a straight line, but they tend to go like this, and then puff.

DR. KAUFMANN: That's right. We're not using regulatory depreciation, in general. In fact, we won't be using an approach to accounting for depreciation that reflects regulatory accounting. Instead, this is supposed to pick up the long-run sort of impact of depreciation on the assets.

MR. HOEY: Just if we're going for a total factor of productivity for the industry, why do we need to separate all the companies individually? Why wouldn't the total at the bottom of the industry be the number you would be using for capital additions, depreciation and all that stuff?

DR. KAUFMANN: That is what we use, but we compute that on a company-by-company basis.

MR. HOEY: For what purpose?

DR. KAUFMANN: It's more accurate. If you aggregate everything up, and then you compute it, you can introduce some biasses relative to doing it company by company, and then aggregating those numbers.

MR. HOEY: What biases do you introduce?

DR. KAUFMANN: Aggregation bias.

MR. HOEY: So what you're saying from a math point of view, one and one doesn't equal two?

DR. KAUFMANN: I mean, there is a bias. If you want to come up with a very detailed sort of calculation of what's happening, you wouldn't look at point A and point B, and then just divide, because a lot could be happening between A and B.

So it's better to look -- it's always better to drill down to the actual cost and the actual outputs that are changing to the greatest extent you can and try to get a measure of that as opposed to just kind of adding everything up, and then trying to get a measure at the end.

It's kind of similar to what we were talking about before about the different capital components. You want different indices, to the extent you can. If the information was available, you would take price indexes for different components of capital and you would divide those as opposed to adding up all the capital, and then coming up with an overall index.

That's an example of an aggregation bias. Same thing on looking at the industry as opposed to individual companies.

MR. HOEY: I can understand an aggregation bias where you're adding up different types of capital, i.e., transformers versus lines versus computers, but I don't understand why the aggregation goes on a company-by-company

basis if we're not doing it on a capital-by-capital type. If you do it on company basis and you are only adding up the total capital at the bottom of the company, you don't have the asset type. You have -- the asset type aggregation hasn't been addressed.

DR. KAUFMANN: It's just -- it's a technical mathematical point, but that's what aggregation bias is. It applies to the individual units. It applies to the individual inputs. You're going to have a more accurate measure if you're doing it on a company-by-company basis. The difference, it's almost never huge, but there can be a subtle difference in the number. Jay.

MR. SHEPHERD: You're not planning to use the company-by-company data except to get to the overall number; right? You're not planning to publish it so you can compare everybody's productivity?

DR. KAUFMANN: That's a good point. For the TFP, ultimately we are only going to use the industry number, but we have to compute the capital numbers on a company-by-company basis anyway, because we're going to do benchmarking for each individual company.

We can't benchmark -- so just from a practical point of view, we can't do total cost benchmarking unless we have total cost measures for each company in our sample. So we have to do it there, and given we're doing it for every company, the right thing to do is to compute TFP as well, and then aggregate it.

MS. MCLORG: I thought Jay just asked -- it wasn't

being used for that, but you're saying it is?

DR. KAUFMANN: It's not be used for TFP. For the TFP, again, the only -- we will not be measuring and we will not be reporting each individual company's TFP growth. That's not why we're doing it. We're only computing an industry TFP growth measure, but we are going to also benchmark total cost. And to benchmark total cost, we need to have a capital quantity and a cost of capital cost measure.

So we have to compute -- we have to do the same process company by company to do the total cost benchmarking.

MS. McLORG: Sorry, just a clarification.

So the capital input quantity you're calculating here will still be used on an individual company base into the other benchmarking? So it's not -- the total productivity factor won't be, but the capital piece of it is identical and will be used in the other process?

DR. KAUFMANN: That's right.

MS. McLORG: So again, I just want to reiterate that using things like generic economic depreciation does -- you can say it's company-specific, but there are things in there that are still generic?

DR. KAUFMANN: Generic in the sense of being industry averages, yes.

MS. MCLORG: No, the economic depreciation, you didn't it's an industry average; you said it's based on -- it's economic depreciation theory, for example?

DR. KAUFMANN: No, no. We would still be looking at

depreciation studies for the distribution industry. So we would still be looking at evidence for electricity distribution.

And again, the evidence that we can consider could include regulatory depreciation rates, what's reported. That could be -- that could be -- that's certainly a feasible approach.

So we could use that in our -- you know, in this D here, what we use as the average D. We could even do that on a company-by-company basis, potentially, although we're not going to have as much information company-by-company, and that will add some complexity to the analysis.

But whatever we use it will be a distribution-specific depreciation number.

MS. BRICKENDEN: I was just going to ask, looking at the time, if people wanted to take a stretch and we'll continue after, say, five or 10 minutes, or whether you would like to motor on through to 4:00 o'clock. We're happy to -- whatever you prefer.

Okay. Short break. Let's break for 10 minutes, and we will resume at 10 to 3:00. How's that?

--- Recess taken at 2:34 p.m.

--- On resuming at 2:54 p.m.

CONTINUED PRESENTATION BY DR. KAUFMANN:

DR. KAUFMANN: So maybe we can summarize the capital measurement issues on slide 16 where essentially to measure capital input quantity for a TFP study and also for benchmarking basically requires four things: A benchmark

capital year, which again we want to be as distant from the present year as possible; measures of capital additions in each year since the benchmark year; a measure of the economic depreciation rate; and index of distributor plant asset prices.

And this asset price index is going to include construction labour. It's going to include the price of the asset itself. It will be a comprehensive measure of distribution asset prices, and StatsCan does have data on distribution asset price indexes for the distribution sector for Canada - not for Ontario, but for Canada - going back to 1956. So we know there is some data on that. There may be others, but we know at least we have that.

So for the working group, some of the issues we will be considering are appropriate values for the depreciation rate and for the distribution plant asset price index.

Now, a related issue, and we've talked about this as well to some extent, is when you're doing total factor productivity estimation and you're doing total cost benchmarking, you need to develop measures of costs, as we well as inputs. So we need to develop a measure of total capital costs in addition to capital input quantity, and cost is going to be equal to the product of quantity times input price.

So for total capital cost, you would compute that as the product of the capital quantity that we were talking about and we were talking about computing, times an input price. And these two formulas here show some examples of

how this can be done.

If you add CKt - that's the cost of capital in year T - multiplied by a capital quantity index from the previous year, multiplied by a capital service price index, which is the WKSt, and remember WKA is -- that is the asset price index. And what this shows, rt here is a rate of return, 'd' is the depreciation rate and WKAt is the capital asset price.

So this is one straightforward measure for a capital service price, and what it shows is basically three things. You have the return on capital, which reflects the rate of return multiplied by the asset price, return of capital which measures the depreciation times the asset price, and then this last piece is a capital -- basically a capital gains issue.

So the idea there is that if you're -- if the price of your assets is increasing over time and you're holding those, then that is a gain to your investors, in a sense.

This is a capital service price index that's been used in a number of places, and it's one possibility for what we're going to use in our work.

But we've also -- we've talked about depreciation, but to implement this part of the analysis and to develop capital costs in addition to capital input quantity, we're going to need a measure of the rate of return in addition to the rate of depreciation.

So one possible rate of return is the Board-approved rate of return for each company. There are others, as

well, but I think that's the leading candidate for what we would use to implement this formula. But an issue for the working group would be coming up with appropriate values for the rate of return. So that's going to be another issue that we will examine. Questions?

MR. SHEPHERD: Yes, I have one question on that. When you're talking about rate of return, you're talking about like a weighted average cost of capital?

DR. KAUFMANN: Yes.

MR. SHEPHERD: And presumably on a rate reflective basis or straight cost basis? So, for example, net income return on equity produces taxes, as well. Is that part of the factor?

DR. KAUFMANN: Taxes is -- that's an interesting issue and we will talk about taxes during the working group as well, because as you know, as everyone I'm sure knows, there have been some changes in taxes policy in Ontario which could have implications for the TFP trend.

So that will be another issue, as well, how we deal with taxes.

MR. SHEPHERD: Thanks.

DR. KAUFMANN: Okay. Well, we've been talking about index-based approaches to TFP based -- TFP measurement, and there are some pros and cons to this approach. Believe it or not, this is the relatively simple approach.

Obviously there are a lot of implementation issues involved but, technically speaking, it's not that complicated to do indexing, and you don't necessarily need

a lot of cross- -- you don't need big cross-sections. You can compute TFP growth for each individual company, for example, and that can be an issue if -- it's wouldn't be an issue here, but it can be an issue in some jurisdictions.

It's not an issue here, because we have 77 distributors, so we have a big cross-section, but in some places it can be an issue.

The underlying techniques for index-based TFP measurement are relatively well established, relatively well understood and, once you get the hang of it, relatively transparent.

We're working from accounting data and we're transforming that into accounting and operational data, and we're transforming that into outputs and inputs, and then using those changes, linking those to rate changes. So those are all pluses for the index-based approach, but there are few potential cons, as well, and one is that we are relying on historical periods over which we're measuring TFP growth.

We want to use this estimate going forward, and there could be an issue that the estimate that we compute historically is not appropriate going forward if the future is going to be very different from the past. So that's an issue with the index-based approach that we have to consider. Whenever we look at whatever measure we're computing historically, we have to ask ourselves whether that's appropriate going forward.

And that can be an issue if business conditions in the

future differ from the past. The cost driver variables, government policy, if those things change in the future compared with the past and there are implications for cost that are different from the past, in terms of cost changes, then again that can be an issue.

Another issue here is if we think back to third generation IR, that used a very extensive time series as the basis for the TFP trend, which was then used for the productivity factor. The Board used an 18-year trend from 1988 through 2006. And it said that it wanted to rely -- its rationale at the time was to rely on as much information as it had available to it.

Now, we're going to have much less information this time and we're probably not going to be able to compute an 11-year or 18-year trend using indexing methods for Ontario, given the data we had.

We did it last time because we were looking at the US, and we have a lot more information from the US. So that's an issue, given the Board's past policy and its decision to rely on a very long-term trend last time.

We're not going to have as long a term this time, and that could undermine confidence in the reliability of the -- of the trend that we compute, because TFP can vary from year to year because of changes in output, changes in the timing of expenditures, things like that, but over time those things tend to kind of even themselves out, particularly in industry-wide basis. And if you have a long enough period, they will tend to even out, but as the

period declines, it becomes more and more likely that you could have anomalies in that period that make that period not representative going forward.

And we know one thing that's potentially anomalous are the impact of recessions. If you have a recession, then output falls, economy wide output for distributors falls. That's going to be reflected as lower TFP growth, but recessions are anomalous, and under the usual scenario the economy is increasing, but we know in the period we have available from 2002 through 2011 there was a very severe recession during that period. So that could be an issue, as well.

Another issue is that companies were coming off of a rate freeze, an extended rate freeze, during -- between the period 2002 through 2011. There could have been some pent-up investment spending and other types of spending, which could be reflected in more input quantity growth in that period than you would see over a longer, you know, more normal sort of period.

So there are some potential anomalies in the sample period that we have available to us, that we have to be sensitive to and ask ourselves whether those are going to be -- if we have a period that reflects those anomalies, whether that period is appropriate going forward.

So given those cons, it's worth thinking about the other approach to estimating TFP, which is –- yes, go ahead.

Q&A/DISCUSSION SESSION:

MR. HOEY: Patrick Hoey from Hydro One.

Larry, I didn't -- I should have asked this a little bit earlier, but you went through the explanation of how you got to the OM&A input cost and the capital input cost.

I didn't see in the slides how they get put together to come to a total input cost.

DR. KAUFMANN: They're added together.

MR. HOEY: Just added?

DR. KAUFMANN: Total cost is equal to OM&A cost plus capital costs.

MR. HOEY: And then you compare that input to the output, and the output is your rates -- revenues; correct?

DR. KAUFMANN: No, the output for TFP growth, the output are -- there are going to be customer numbers' volumes and kilowatt-hours. So that's going to be your output growth.

Your input growth is going to be, actually, the deflated values, so it's going to be the quantities and not the expenditures. So it's going to be the quantity of O&M and the quantity of capital aggregated together, where those -- basically, it's going to be a weighted average, where you have the cost -- the share of cost that applies to OM&A is the weight that it gets, and then the capital share of cost is its weight.

So just for an example, to make that more concrete, let's say your OM&A costs -- your OM&A inputs increase by one percent, and OM&A accounts for 40 percent of your costs, and if your capital increases by three percent,

that's six percent -- that's 60 percent of your costs. Then you've got 1.8 plus 0.4, a 2.2 percent growth in input quantity. And let's say you've got measured output quantity of 2.8 percent customers' volumes and kilowatt-hours, then 2.8 minus 2.2 is 0.6 percent TFP.

MR. HOEY: Thank you.

DR. KAUFMANN: Okay. So that's the indexing approach.

The econometric approach is -- basically what that does it takes index-based TFP numbers, but it decomposes those into a variety of TFP drivers.

And if -- I wrote a concept report. I'm not even sure when that was. I believe it was in mid- to late 2011, but that was a report that kind of looked at these issues, measurement issues, from a very high level and a certain amount of technical detail.

And I have an appendix in there which lays out this calculation; I think it's appendix 1 of the first concept report. And what that shows is that you can decompose TFP growth into a number of specific identifiable components of TFP growth, and those components include things like the time trend or technological change, the impact of economies of scale on TFP growth; so as output grows, the impact that has on your TFP. And then changes in different business conditions that aren't going to be reflected in output, but could be reflected in your cost; things like changes in customer density, changes in undergrounding of lines, those sort of things.

You can actually do some statistical analysis and

regress due to statistical regression of TFP growth on these various components, or you can also get these parameters from cost functions. And you can estimate the impact of each of these business conditions on TFP growth. Okay? That's the econometric method.

And there are some pros and cons associated with this approach. Let's start with the cons.

It's more complex. Econometrics is a more complex technique than indexing. It usually requires a bigger cross-section of companies, although that's not necessarily an issue here because we have 77 companies operating under a wide array of circumstances. And the techniques and results are usually less well understood, and for that reason potentially more contentious than the techniques of indexing.

However, we are going to be doing econometrics as part of our work for benchmarking, so we're going to be doing econometrics, anyway. So the econometric approach to TFP measurement could be a byproduct of our benchmarking work. We can potentially use that same information to project TFP. And the way we would do that is we would identify the cost drivers, link those to that function that's in appendix 1 of the previous concept report, and take expected values for those business condition variables, stick them in the model and then generate predictions of TFP growth for the industry. We can do that for the entire industry, or we can do that company by company if we wanted to.

So -- and that's the -- those are the benefits of the econometric approach. If you wanted to do it company by company, which probably isn't going to be a factor here -- but we could reflect differences in company conditions and differences in, say, the impact of undergrounding, the impact of changes in customer density among companies, and the impact that those changes have on distributor A versus distributor B.

But more importantly, the econometric approach doesn't require extensive time series data like the indexing approach does. You don't need 11 -- 18 years of data to estimate it, because the model gives you what you use to estimate it, the model parameters. So it can kind of overcome the constraints we have of just relying on the 2002 through 2011 period. This is a way to get beyond that limited -- that limited amount of time series data.

And it's also potentially valuable if the future is different from the past, because you can take variables that reflect those TFP drivers and get estimates of what those variables are, going forward. And if they're different than what's been observed historically, then you can come with a projection going forward, that might be different from measured TFP historically.

So that's the second bullet point under the pros. It can capture differences in future business conditions compared with the past.

In that sense, it's a potentially powerful technique and it's a way -- it deserves consideration here, because,

one, we're going to be generating the econometric results anyway, so we're going to have the underlying analysis. We can use it for TFP projection.

But it's going to be a little more complicated, and it's a whole other issue of -- something to discuss, but again, it's worth thinking about because we only have this relatively short period from 2002 through 2011, and that period includes a big recession and it also includes the expiration of the rate freeze, both of which might be anomalous and both of which might distort what we measure for TFP over that period.

And because of that, what we measure may not be appropriate, going forward.

MR. HOEY: Patrick Hoey from Hydro Ottawa.

If I understood what you were just saying, you can use the econometric model by using some kind of forecast data going forward, and give you potentially a better estimate of what the future is going to be?

DR. KAUFMANN: You could. Or you could even use the average rate of growth for each of variables over the historical period.

MR. HOEY: Okay. And would the future forecastability of the econometric model depend upon the forecast variables that you use going into that?

DR. KAUFMANN: Yes. Whatever variables you plug into the model, yes, that's going to directly impact the projection.

MR. HOEY: And where do you get the forecast data

from?

DR. KAUFMANN: Well, we could always look at -- the simple answer is just to look at the historical record and just say that the long-run rate of change is going to be reflected in history and we can project that going forward.

Or we can come up with different estimates, if companies have different estimates.

MR. HOEY: But the estimates would have to be five years, since we're locking this down for five years; correct?

DR. KAUFMANN: Yes. It would have to be the average rate of things -- average rate of growth of things like customers' volumes, underground lines, change in underground lines. These would all be on a rate-of-change basis, so that kind of reduces the forecasting burden to some extent.

MR. HOEY: Okay.

DR. KAUFMANN: Again, I know there are some complexities and issues that would be involved with this, but I'm raising it, given the fact of the data constraints we have for indexing.

MR. STEPHENSON: It's Richard Stevenson. Without meaning to offend any econometricians in the audience, this has an element of black magic to me, and I mean that in the sense that it's almost entirely opaque to me in the sense that all of the -- standing back from it, you have no idea how the results are arrived at. And insofar as public acceptability is sort of an important value, how do you run

that to ground?

Like, I'm accepting for the purposes of this question that you get valid outputs. My question is: How do you sell that to people as being valid, in fact, as opposed to simply, Trust me it's right?

DR. KAUFMANN: Well, I think trust is going to be built up to the greater extent that people can understand the econometrics. That is a process that takes a little effort. But I think the more you become aware of what's actually happening, the more you understand it, I think the more you will buy into the fact that you will get something reasonable out of it. So that's one thing I can say.

I agree it's always going to be a more opaque sort of approach and technique than indexing. But remember we are using it on the benchmarking model, too. We are doing econometric benchmarking.

MR. STEPHENSON: That doesn't necessarily give us any comfort. The fact that something else is opaque doesn't help this one.

DR. KAUFMANN: Fair enough. And another thing on the econometric model is there are confidence intervals there that we're using. So we're not just basing it on the projection -- you know, on the actual prediction. This would be based on a point -- this would generate a point prediction. We wouldn't be looking at confidence intervals.

MR. McLORG: Sorry, Richard, it's Colin at Toronto Hydro. What audience are you trying to convince here?

What target audience were you just referring to?

MR. STEPHENSON: The people in this room, the LDCs, the people that are going to be governed by the outcome have to have a sense that they're being treated fairly as number one, and then, number two, the people that are ultimately going to be affected by this, which are the end users, to the extent they start getting on the phone and complaining about the fact that their rates are what they are and want some explanation.

Public acceptability is a pretty well understood foundational principle of rate-making.

DR. KAUFMANN: I'm just kind of thinking out loud here, but there are a number of things you can do to build understanding and awareness and comfort with an econometric approach, and one is, for example, if we were to do this for both Ontario and the US, we could do use back casts of what the model shows about TFP.

So we could say, Here is what our model shows, and we have some historical values on what the drivers were. What does the model show us about TFP growth? What would it project for TFP growth for a historical period?

And we can compare that to actual TFP growth, and if it shows it's actually in the ball park, then that's evidence this is actually doing a pretty good job of picking up the underlying reality.

DR. YATCHEW: Adonis Yatchew. I'm here with the EDA. There is a maxim in law that says justice must not only be done, but it must be seem to be done, and I think that's

the centre of -- the heart of your point, and I agree with that.

Some of the best models that I have seen are very simple models with a very small number of variables. Unfortunately, there are quite a few confounding factors in this setting, and I might suggest that consistent with the kinds of report I've seen PEG produce in the past, and maybe more so in this direction, you might want to put the technical stuff as far back in the appendix as possible and actually just highlight what it is the model is really saying in graphical terms preferably, and to some extent in -- or as much as possible in language.

If somebody were to come up with a nice alternative for setting these various kinds of regulatory indices that is very simple, I would love to see it. It is one thing to say the technology is complicated. It is another thing to say there is a useful alternative.

MR. McLORG: If I may be permitted one more comment -- I think I agree with Adonis -- suggest that our concern about the validity and the robustness and the soundness of the methodologies used by the Board is I think a separable question from our ability to explain it to any identified audience.

And I think that the explanation, as was suggested by Adonis, can be made. It would probably have to be pitched to -- at an appropriate level for the audience in question. And I would never, for example, attempt to explain -- I would never even ask how the guy that fixes my car actually

does it, but I do want an explanation from him in terms that I can understand.

I think the same thing can be provided for the econometric approach. So I'm just very anxious that we not constrain the actual fundamental approach that's chosen or that's used on the basis that it's hard to explain to our grandmothers. In some degree, this is rocket science and it deserves to be, because this is our fourth go round at IRM. We deserve, all of us, to have increasing level of sophistication in the way we approach this.

DR. KAUFMANN: This is obviously going to be an issue for discussion for the working group. Econometric -- you know, this is a valid approach. It is a more technically complicated one, but it deserves merit, given the fact that we're grappling with the limited information we have, and this could be a relevant piece of information that could at least let us know whether whatever we get out of the index-based approach is reasonable.

It could be a sanity check on the indexing method, or as Lisa said an insanity check. Hopefully not. Okay.

So that is the productivity factor, and now let's talk about total cost benchmarking. The benchmarking was used in third generation to set the stretch factor. Again, there were two benchmarking models. There was an econometric model, and then there was a unit cost model.

The unit cost model compared each company's unit cost to the peers in its peer group and looked at the difference between the two. And in fourth generation, we are going to

update both the econometric and the unit cost models. So we'll update the models that we developed last time and applied to third generation IR, but this time we're going to be including capital, as well as OM&A costs in the analysis.

And our intent is for those capital costs that we add and that we use in the benchmarking work to be identical with those we develop and use in our TFP estimates.

In the Board report in October, it said the stretch factor assignments under fourth generation are going to continue to be based on or at least informed by assessments from the two benchmarking models.

MR. HOEY: It's the last line there. Can you point to me in the RFP book where the two benchmarking models will be used for the stretch factor assignment?

DR. KAUFMANN: I don't have the report in front of me, but it did say it would -- you know, basically the approach that was used in third generation for setting stretch factors would be used at the same time -- you know, would also be used in fourth generation.

MR. HOEY: But I think earlier -- I asked you a question earlier today, and you said that if we go to a total factor productivity model, we wouldn't need these two things. We only used the unit cost because we only had an O&M model last time, and now that we're going to a total cost model, that wouldn't necessarily be needed.

So I guess my question is: Why do we need the unit cost piece to go with this?

DR. KAUFMANN: Why do we need the unit cost and not just the econometric piece?

MR. HOEY: Yes.

DR. KAUFMANN: Because if you have two tests -- right now we have two benchmarking assessments. And the way the stretch factors are assigned right now are based on kind of a coincidence. You know, it's kind of a -- two positives. If you have two positive measures of being efficient, it then you're assigned to the efficiency -- you know, the most efficient cohort. If you have two positives measures of being inefficient, then you're assigned to the inefficient cohort. And if you're not, then you're in the middle.

So having two tests gives you more confidence and it makes the whole assignment of firms to different efficiency cohorts more robust. You're going to have more confidence of that if you have two positives as opposed to one. So that's the reason for having two; both the unit cost and the econometric.

MR. HOEY: Only if the two tests are fair?

DR. KAUFMANN: Sure.

MR. HOEY: Okay.

DR. KAUFMANN: But even if they're not fair, you're going to have more confidence than if you just had one.

MR. HOEY: If they're not fair, you're going to have more confidence? More confidence in what?

DR. KAUFMANN: If you had one bad test, then you're going to have less confidence than if you had two bad

tests.

MR. HOEY: If I have one good test and one bad test and the bad test outweighed the good test, then I have less confidence, don't I? Or no confidence?

DR. KAUFMANN: These -- you can contest the basis of the econometric and unit cost models themselves. That's fine. But the idea is that we're trying to develop the best models we can, given the information we have. And if we have two of them, then we're going to have more confidence that what we're getting for efficiency evaluations are, in fact, fair. That's the idea.

MS. BRICKENDEN: I've just been checking the actual text, and no, it doesn't make a specific reference. It just says that it would be assigned based on total cost benchmarking evaluations, one or more, you know, it's -- I think we need to talk about that. If we have really good confidence in it, then we go with one. If we need two in order to have a more robust and confident result, we continue using two.

MS. GIRVAN: Julie Girvan for Consumers Council of Canada.

I was just wondering, because I know we're going to be discussing this and -- to a large extent, stretch factors during the working group, but it would be interesting -- at least from my perspective -- to get some insider views from the utilities that maybe won't be on the working group about the stretch factors in third-generation IRM and what your views on those were, and then if you see going forward

this total cost approach, if you think that's better.

I'm looking at Patrick's face. I just think it would be interesting if we had a sort of a broader perspective.

MR. HOEY: I can certainly give you Hydro Ottawa's perspective on at least one half, the unit cost assignment to peer groups.

It doesn't do what the outcome is expected -- what it says it's supposed to do is to encourage productivity and for people to get better.

There is no possible way for Hydro Ottawa to move from cohort 2 to cohort 1. Impossible economically, no matter what we did. The numbers just don't jibe with themselves, and it's because -- it's the peer grouping. It's about who -- which group you get into is more important than actually what your own performance is, so that's why we think it's flawed.

You can show -- you can take certain small companies that were put in one group and if you just move them to another group, basically from northern to southern -– and one wonders why you ended up in the north anyway, in the first place -- all of a sudden they lose their cohort standing. They drop immediately from 1 to 2, and there's been no change in their performance at all, no change in anybody else's performance.

So all the peer grouping does is say: Depending on where you end up and what group you're in, you're great.

There is another group of LDCs that are in the GTA area. They are all good performers from a unit cost basis.

They have very low unit cost numbers, but because they're all so tightly in that group, the way the system works is that your percentage gain over the average -- well, if you have a tight group with no average, where everyone is very, very close to the average, none of them appear in the top group because it's mathematically impossible.

So it comes down to the selection of what group you're in and how lucky you get with -- whether you get a really bad performer in your group. And if you do, you're away to the races and you'll never be pulled out.

And so the people that moved over the last four years, there was only a few utilities that moved from the different groups, and generally it's the same people moving back and forth between the groups. There was no material shift of someone moving from the middle of a pack up into the other group, or down in a group. It was just the people on the fringe, and that's just an anomaly, more than anything.

MS. BUTANY-DeSOUSA: Indy Butany, Horizon Utilities.

I think I would add to that -- and maybe you're going to address this in a couple of slides, so I might be pre-emptive, but given that Patrick has led the way into peer groups, there was an extensive discussion in 2008 on the matter of peer grouping.

And I guess I would just be interested as to whether the peer grouping that existed in 2008 that gets you to the allocation across the three cohorts is what's going to underlie the effort going forward, or given that there was

significant submission by -- it was called CEIRM, the Coalition for Effective Incentive Rate Mechanism, which comprised 22 LDCs, whether the submissions therein are going to be revisited on how the peer groupings worked or didn't work.

DR. KAUFMANN: Well, the benchmarking analysis, the unit cost analysis would -- it would change. When we move to a total cost approach, the cost drivers can change, the implications for cost can change. And because of that, I think it makes sense to consider different peer groups, as well.

So that was going to be and that's -- we think that will be an issue for consideration for the working group, and potentially for our group as -- our work, as well.

MR. McLORG: I apologize, because I'm on the working group and so out of Julie's class, but just very quickly -- I was going to put this in a form of questions to Larry, but I guess our view is that there doesn't seem to be any additional or independent information that's brought to the analysis by the unit cost analysis.

Really, what we understand is that the unit cost peer grouping assumes that there are certain significant cost drivers that have been found through the econometric testing to be so, and utilities are grouped together based on the presence or absence of those cost drivers, but the value for the variables represented by the cost drivers -- aside from the binary ones like Canadian Shield, where it's either a one or a zero -- but the value of the variables

like degree of undergrounding, customer density, what have you, all those things, is actually not accounted for or taken into account in the unit cost analysis.

The unit cost analysis seems to be a devolution of the econometric benchmarking, because when you -- if you take a group, like small northern medium to high undergrounding, if you look at those numbers -- which I did -- you'll see that on the variables there is a great deal of difference between the utilities' variable values. One has a value of three percent; another has a value of 18 percent.

But when you simply compare the unit costs without taking into account the influence of those variables on the unit cost, then it seems to me that you're not adding information, you're actually losing information.

So I would agree with Larry that we could have more confidence if we had two independent tests, but what I'm not sure of right now is what additional information is brought by the unit cost analysis. It seems to me that the unit cost analysis simply subtracts information from the analysis, and doesn't add anything new or able to triangulate with.

DR. KAUFMANN: I would say the unit cost analysis doesn't really subtract. It accounts for those factors in a different way.

So the outputs are already reflected directly in the unit cost measure itself, and then the peer groups are designed to reflect for the other factors, you know, the density, urbanization, being on the Shield, et cetera.

So the design of the peer groups is another way to pick up those business conditions.

Now, I agree that it does it in a -- it doesn't pick up the magnitude of those differences, which is important, but it is another way of looking at it.

And one potential benefit from that is the whole opaque -- the opaqueness issue. When you're talking about econometrics, it is a more complicated technique and you do get -- you control for more things in coming up with the efficiency evaluation, but a lot of people struggle with what you're actually getting as the output.

Here you're actually using something that companies can see and understand: Here are our costs, here are our unit costs, here are the unit costs of our peers.

So, you know, in a sense you could say that you're sacrificing a degree of the precision of picking up the magnitude of those differences within the peer group for having a more direct and explicit comparison that people can understand.

MR. HOEY: Larry, I would tend to agree you can use unit cost in that way and that unit cost -- the lowest-unit-cost LDCs in the province would be rewarded, but that's not what happened. The lowest-unit-cost LDCs in the top 10, you know, two or three of them didn't get anything. They were stuck in number two.

And they are a top performer based on unit cost. They're also a top performer in terms of the time series. Over time they've either stayed very close to where they

originally started from or have been reduced, and there is no reward.

There is no translation between your actions and where you end up. There is no alignment between that, so why would management waste their time doing it if what you're doing doesn't result in any change?

DR. KAUFMANN: I think that's potentially a relevant point. If for some reason a given peer group concentrated a lot of the good cost performers, which I think is what you're saying, then in a sense you're not getting the same -- you're getting a different comparison than if you happen to be in a peer group with a lot of bad cost performers.

That's an interesting issue and we can look at that potentially as -- you know, kind of look at -- I mean, that's something we could investigate to see to what extent that really is a problem.

MR. SHEPHERD: Aren't these two methods supposed to end up measuring the same thing two different ways? That's my understanding of it, and if that's the case, then if utilities are ranked differently from one to the other, isn't that something you can then empirically investigate to find out why one method is ranking differently than another, and see whether one is more reliable than the other?

DR. KAUFMANN: I'm not sure how you can compare just raw scores like that and see whether one is different than the other. That really depends on the underlying techniques themselves. That's really an issue of whether

one benchmarking method is more reliable.

MR. SHEPHERD: What I'm hearing from Colin and Patrick is that on one method the results are quite different from another method, and that's hurting some utilities. And if that's the case, doesn't that imply that one of the methods - we don't know which one - is wrong or poor?

DR. KAUFMANN: If there were significant differences between that, yeah, I think we could say that. But it wouldn't be that surprising if there were a little bit of variation between the two methods. We're trying to make inferences on something which is difficult thing to make inference on, which is the underlying efficiency of a company.

So we have two different approaches. There are pluses and minuses of each approach. Obviously the econometric approach is more sophisticated. I think it is more powerful. It controls for differences across companies more precisely. That's all to the good, but what you get out of it is a measure that some people have difficulty understanding.

The unit cost approach tries to get at that in a different way, but what you see is something that's -- I mean, you can actually see the differences, so it's more tangible.

MR. SHEPHERD: Can I follow up on one other aspect of that, and that is that the Board has said in the RFE report it's going to consider having greater differences in the stretch factors, and presumably that means that you have to

have a more reliable benchmarking measure.

Have you given any thought to how to do that, how to test whether your new measure is more reliable than the old measure if you're going to make it worth more money?

DR. KAUFMANN: I haven't given that any -- you know, I haven't really given it any thought. At this point, we're still starting, but we will certainly look at that.

MR. SASSO: Just a comment on Julie's question about what the utilities who aren't going to be participating any further think about it.

I guess our thought is there are some utilities who will -- you know, if you're in the top bracket, you wave this around and you say, We're a top-performing firm, which of course is incorrect, it means that you're one of the most efficient utilities, but efficiency isn't just about -- or being a top performer isn't just about efficiency. It's also about effectiveness.

And I think if you look at the list, there are probably some who have done at various points very well or who are not necessarily effective, and I think there are some who have ranked probably not as well who are actually quite effective.

I think the scorecarding we were talking about earlier today is about effectiveness. It's about actually delivering results, the outputs that you're actually providing in terms of service and so on. And in my mind, that's what effectiveness is about.

You can do very well by not spending any money, and

you'll do very well by not spending any money whether it's total cost per customer or OM&A per customer. It doesn't mean you're a top performer. It doesn't mean you're effective. It just means you're efficient, and that's okay, but you have to call it what it is.

DR. KAUFMANN: That's a very good point. And if you look at slide 23, issues for the working group, the last bullet point there is whether other performance measures, including the sort of performance measures that would be included in the scorecard that are provided under the RRF, should be examined when establishing stretch factor values.

The Board can potentially look beyond this analysis and look to other information that's going to be included in the RRF and measured under the scorecard and use that, as well. The effectiveness sort of measures, reliability, all those things potentially come into play on the scorecard and can inform the stretch factors, as well.

MS. KWIK: I really thought that was the intent of the scorecard, is it not? Is that still a question whether you would be using the scorecard in evaluating the distributors in terms of the stretch factors that should be assigned?

MS. BRICKENDEN: In terms of stretch factor assignment, yes. We haven't exactly determined exactly how that would be done. That's what we need to consult on.

MS. KWIK: But the objective is to incorporate it into benchmarking; right?

MS. BRICKENDEN: Yes.

MS. KWIK: I just wanted to confirm.

MS. GIRVAN: I just had a question in terms of Andrew's point about this idea you might have a utility with low rates that appears efficient, but in fact they are not serving the customers properly. How do you get around that?

DR. KAUFMANN: You mean with respect -- in the benchmarking models themselves? Well, we can include some variables in the benchmarking models, for example, different measures of reliability, SAIDI and SAIFI.

Those data exist. It was part of the group on reliability and that whole initiative on reliability management and reliability regulation. We know there are issues on how reliability data are collected among companies, but you can potentially use those data as variables in the model and control for those so you can get the impact of those on costs.

So if some company is in fact providing higher reliability at a higher cost, it's getting credit for that, in a sense. Companies with higher reliability, if that's showing up as a significant cost driver. And the companies that register higher reliability would then get credit for that in their cost prediction and that would make them look more efficient. That efficiency gain would come from providing that service reliability.

There are complications that come from that, too, because measured reliability doesn't just depend on cost. It doesn't just depend on your performance. That's also impacted by how urban or rural your service territory is,

what sort of vegetation you have, whether all those things vary. We really should take that into account and get a good measure of kind of the underlying reliability and not just potentially the measure, you know, the underlying reliability performance and not just measured reliability.

I'm sorry, let me just finish up there. That's the way to do it statistically. You can also do it a little bit more informally just as -- through the Board's discretion, by evaluating performance on a number of different categories under the scorecard.

MS. BUTANY-DeSOUSA: Indy Butany, Horizon Utilities. So now you're on the slide I was hoping you were getting to.

So on the peer grouping, then, as the slide indicates, currently there are 11 peer groups, plus Hydro One, so a total of 12. One of the issues for the working group is potential modifications for the peer groups.

Are you considering reducing the number of peer groups, or is it wide open?

DR. KAUFMANN: I think it's wide open. We'll talk about it. I think this is an issue we can change.

MS. BUTANY-DeSOUSA: I'm sorry?

DR. KAUFMANN: I think it's wide open. We'll talk about it, and, I mean -- I think this is an issue that we can change.

MS. BUTANY-DeSOUSA: I'm sorry?

DR. KAUFMANN: I think it's wide open. There is no reason we have to stick to peer groups that were

established last time.

It's going to depend –- but I think we want the analysis to guide it. If we find there are different cost drivers that we're identifying, if for some reason there is some anomaly in the way companies were assigned to different peers, and let's say there's a concentration of good performers in, say, on -- according to the econometric model, in one of the peer groups, then that might be kind of an unfair –- you're all being, you know -– you're being benchmarked against the best of the best, as opposed to, you know, an average. Your peers are all above average, kind of Lake Wobegon.

Those are the sort of issues that we can look at and evaluate, and to see whether or not the peer grouping that we had was reasonable or whether we should change it.

MS. BUTANY-DeSOUSA: I think there was significant input in the last consultation on whether or not the peer groupings as they stood were appropriate. And so I appreciate hearing that there is the opportunity to review this exhaustively.

MS. KLEIN: We parked Jim Huntington's from Niagara-on-the-Lake cohort question. His question is:

> "Density of an LDC's distribution system will have a major impact on OM&A. Our next closest cohort has customer density of twice that of our utility, while the other three have multiple densities. Will there be a better recognition of the effect of density as a cost driver in the

future?"

DR. KAUFMANN: First, there will be a different analysis, because we will be looking at total cost as opposed to OM&A. Again, we're going to be driven -- we're going to let that decision be based on the empirical analysis, what that tells us on customer density.

We know that's a cost driver, and we want to make sure that that's reflected appropriately in the peer groups, assuming that we do go forward with the peer group analysis.

MS. KLEIN: I have another question from Pauline Welsh from Orillia Power:

> "Earlier, Jay Shepherd asked if any change resulted from the use of OM&A and benchmarking for third-generation IR. A comment followed that there was an increase in labour and overhead capitalization in aggregate for the industry. As a utility being measured against its peers, our immediate concern is that comparability is flawed due to inconsistent capitalization policies with respect to labour and overhead costs associated with admin support costs. Not all utilities made these change; i.e., utility maintained original capitalization policies as a result are being penalized in the process through the stretch factor. Will use of total distribution cost and benchmarking address this issue? Is total distribution cost simply determined by adding

capital and OM&A?"

DR. KAUFMANN: The answer to that last question is yes, that is how total cost is computed. And I think to a large extent, it does. If they're just reallocating cost between OM&A and capital, then it doesn't matter when you're looking at total cost.

Any other questions?

Well, going forward for PEG, the next step for us is to finalize the data set. We have a lot of the data, the 2002-2011 data, the MUDBANK data, but we're still waiting on -- and the low-voltage data. We're still waiting on potentially some data on the -- historical data on Hydro One's distribution system before 2002, and we're waiting on the smart meter data, which Staff is going to request from the companies in a data request that's going to go out shortly.

So the first step for us is going to be to finalize the data set -- the information is still coming in -- put that together, include the input price variables, the business condition variables that we would use in the econometric model, get all that together.

At the same time we're doing that, the working group meetings are going to start tomorrow and we'll be looking to those to explore these issues even more and to incorporate any input from stakeholders into our analysis in terms of what makes the most sense.

And I do appreciate the critical comments on what was done in third generation. It can always be improved on, so

if there are any things that didn't work out, it's good to find out about those.

And three months from now, we're going to release our report and that will include recommendations for the inflation factor, productivity factor, and the cohort assignments for the industry.

Yes?

MR. BAKULEV: Alex Bakulev, from Toronto Hydro.

Larry, have you considered to include a North American data set into the total benchmarking models, not just Ontario ones?

And I'll explain why. In Ontario, we have two outliers, Hydro One and Toronto Hydro. So if you consider the total 75 utilities, these two has their –- by far the largest number of kilowatt deliveries, customers, cost and so on. There are two concerns that kind of arise from these two extremes.

The first one is that outliers included in the model may skew the results for both groups, for the vast majority of utilities and for the larger ones, right?

And the second one, that having only two of them imply that they may have some unique cost drivers that are not reflected in the econometric model. So for example, City of Toronto, it's the only city in Ontario that has two and a half million customers, and quite dense. To be able, for the model, to pick up this variable, you have to have some other utilities with the same business condition, right? However, right now we don't have it.

In some research that we did internally, we see that sort of the urban centre is the major cost driver for the utility, bigger than any other business condition driver.

DR. KAUFMANN: I'm certainly open to the idea. We have plenty of US data at PEG. We could certainly incorporate that in the econometric analysis.

I think the issue would be the Board has said that it won't rely on Ontario-specific analysis for the basis for the productivity factors and the stretch factors. So I'm not sure whether including US analysis in our studies would satisfy that requirement.

MR. BAKULEV: These just show that kind of without including these unique cost drivers, the results, the outcomes, may be skewed, and unfairly for --

DR. KAUFMANN: Again, I'm certainly open to that if it leads to more reliable and robust -- and I think you make a good point. It probably would lead to more robust estimates of the econometric model for -- particularly as it applies to Toronto Hydro, because we would have more big city companies in that sample.

So we could certainly do it, and for the purpose of coming up with better econometric estimates.

MR. SHEPHERD: Larry and Alex, I guess if any utilities have their own research on some of these cost drivers and how they -- and especially time series data and things like that, I think it would be useful for the working group to have this stuff. If you have stuff available, I think it would be useful if we got to see it.

MR. BAKULEV: Yes, we have -- we'll share it.

MS. BUTANY-DeSOUSA: Indy Butany, Horizon Utilities.

I was going to add that one of the ways around what Alex was getting at not only is the utility-specific data, but I think from some of the discussions that we've been having that you can't just -- when you look outside your window and you look at the way the peer grouping was done previously, a northern utility that was grouped as northern previously likely isn't a northern utility, and so it might be useful for the benefit of the working group -- Horizon is not on the working group, but would be willing to make presentation to the working group on influencing factors on peer grouping.

And given that you are open to issues that didn't work last time, I would put that out there. And we would be happy to make that presentation.

DR. KAUFMANN: Any other questions?

Lisa, was there something you wanted to... no? Okay.

MS. BRICKENDEN: Are there any other questions on the line there, Laurie? No.

MS. KLEIN: No.

CLOSING REMARKS BY MS. BRICKENDEN:

MS. BRICKENDEN: Well, if there aren't any further questions for Larry, I would like to wrap up just first with thanking you all for having this conversation with us today. And, yes, we're going to have quite the aggressive schedule for the working groups starting tomorrow.

Briefly going over our next steps, I had a couple of

conversations with I think two of you, but just going over it more broadly so that everyone hears, the working group meetings are going to be carried out over the next two months. There are eight working group meetings, the first four focussing on the performance and scorecard, the latter four focussing more on the econometric work and the benchmarking.

The goal is to have a Staff report to the Board issued for stakeholder comment in April, along with Larry's consultant report. We also would like to invite you back to have a discussion on that Staff report and the consultant report in April. That stakeholder meeting would be followed quite quickly afterwards by a stakeholder conference, where we would like to have a discussion with members of the Board on the specific outcomes of the econometric work and the benchmarking.

Written comments would be due in May, and, based upon the consultations, the working group materials, the Staff reports and our subsequent discussions at the stakeholder conference, the goal is for the Board to issue its supplemental report and for Larry's final, if need be, report in June, to be issued in June. That would include the specific rate adjustment indices, the values for inflation, productivity and potential consideration on the stretch factor values.

Are there any questions at this point? Well, thank you very much. It was a very productive day.

--- Whereupon the conference adjourned at 3:58 p.m.