ALBERTA UTILITIES COMMISSION

Application No. 24116-A001
Proceeding ID No. 24116

DISTRIBUTION SYSTEM INQUIRY

P R O C E E D I N G S

Volume 1
June 24, 2020
Held via videoconferencing
Calgary and Edmonton, Alberta

Proceedings taken via videoconferencing at the Alberta Utilities Commission, at suite 1400, 600-3 Avenue SW, Calgary, and 10055-106 Street, Edmonton, Alberta.

Volume 1
June 24, 2020

Don Romaniuk	Chair
Tracee Collins	Commission Member
Henry van Egteren	Commission Member
David Reese	Commission Counsel
Randy Lucas	Commission Staff
Dr. Frank Wolak	Commission Staff
Olex Vasetsky	Commission Staff
Geoff Bourque	Commission Staff
Abhinav Ayri	Commission Staff
Carl Fuchshuber	Commission Staff
Scott McCallum	Commission Staff
Ragaey Habashy	Commission Staff
Donna Gerbrandt, CSR(A)	Official Court Reporter

(PROCEEDINGS COMMENCED AT 9:02 A.M.)

THE CHAIR: Good morning, and welcome to today's virtual meeting for the Combined Module of the Distribution System Inquiry.

My name is Don Romaniuk. I'm a Commission member at the Alberta Utilities Commission, also referred to as the AUC. In light of recent events involving the government's appointment of Carolyn Dahl Rees as the new chair of the Commission, there have been

organizational changes to the composition of the Panel for this proceeding. As a result of those changes, I'll be chairing this meeting today for the Distribution System Inquiry initiated as AUC Proceeding 24116.

On the Panel and with me in Calgary today, but at a socially acceptable distance is Commission Member Tracee Collins. Also on the Panel, but at an even more socially acceptable distance, in Edmonton is Commission Member Henry van Egteren.

Assisting the Commission today are Commission counsel David Reese, who will also be moderating today's virtual meeting.

Staff members assisting us are Dr. Frank Wolak, Olex Vasetsky, Randy Lucas, Geoff Bourque, Abhinav Ayri, Carl Fuchshuber, Scott McCallum, and Ragaey Habashy. Staff members are joining us from both the Calgary and Edmonton hearing rooms.

While I would love to see everyone's faces to welcome you to our virtual meeting, I would ask that you keep your video turned off unless prompted otherwise. I understand that we have at least 75 representatives and parties participating in the inquiry, and if we all turned on our videos at once it might overload the available bandwidth.

Today's virtual meeting is still new for us at the AUC. We have attempted to take steps to make today go as seamlessly as possible, but I ask for your understanding and patience if we have any hiccups along the way today.

I would like to take a moment and thank all parties for your contributions to date on the Distribution System Inquiry. Parties have filed well thought out and comprehensive submissions on all of the topics in scope for this Combined Module. Your submissions are assisting us as we think about the future, possible evolution of the utility distribution systems in Alberta.

To that end, the purpose of today's meeting is to facilitate an efficient and in-depth exploration of a few select topics within scope for the Combined Module. If certain issues raised by parties in their submissions are not touched upon during today's discussion, this should in no way be seen to minimize the importance of those issues.

As you know, the Commission has asked the authors of the independent evidence submitted by Charles River Associates; the Brattle Group; Energy and Environmental Economics Inc., E3; and InterGroup Consultants to actively participate in today's virtual meeting.

5

Today's discussion may evolve in such a way that the Commission may also call upon other parties to answer a follow-up question.

Over the course of this process, the Commission has consistently stated that it has undertaken this inquiry to map out the key issues related to the future of the distribution system and establish the regulatory agenda for subsequent proceedings that will consider, and then implement, the regulatory framework necessary to accommodate emerging economic and technological forces. Resolution of the issues identified in the inquiry will take place in subsequent proceedings.

Staff and Commission members will ask the invited individuals questions to help the Commission think through whether, how, and to what extent it may want to address some of these issues in subsequent proceedings.

I will now turn it over to David, who will be our moderator for this meeting, to explain how the meeting will be run and to get us started. Thank you.

MR. REESE: Good morning, everyone.

My name is David Reese and I'm counsel of the Alberta Utilities Commission. I'll be moderating today's meeting.

A transcript will be taken of today's meeting. For the purposes of obtaining an accurate transcript,

6

participants are requested to refrain from speaking at the same time. I may ask you to repeat yourself or to slow the pace of speech. You can obtain a copy of the transcript in the usual manner by contacting the reporting firm, Amicus, directly.

This meeting is also being recorded. Understand that it will be archived on the AUC website for up to 30 days following the close of the meeting.

A live stream of this meeting is currently open to the public on the Commission's website.

The messaging and comment functionality in Zoom will not be monitored during the virtual meeting, so we ask that you not use the chat function of this meeting.

If you as a representative have connection issues, please email webinar@auc.ab.ca and include your phone number. A member of our IT team will try to help you if the problem is on our end. Further instructions are provided in Exhibit 0680, that is, 24116-X0680.

Given today's video configuration, the yellow perimeter in Zoom that highlights who is speaking may not be an accurate reflection of who is speaking, as I'm sure you already noted as I am speaking.

If Commission staff or Panel, or one of the lead representatives of the four consulting groups losses connectivity, we will likely pause for a break to

7

re-establish the connection. If a representative of another party losses connectivity, we may continue with the meeting and it may be easiest for that individual to listen in using the public link available on the AUC webpage.

My role as moderator today will be to help direct speaking order and keep us on schedule. For each topical session a designated AUC staff member will read the questioning. A question may be directed to a specific consultant group, or more generally to the panelists of consultants. Questions directed to a specific consulting group will be directed to the group's lead representative. A question may be redirected by the lead individual to another person in their group or the group may briefly confer using their own private messaging, as they might whisper amongst themselves in an in-person situation. Alternatively, the individual that is called upon may decline to respond.

If someone other than the lead individual provides the answer, the person answering the question should identify themselves by name prior to answering the question. This will allow the court reporter to properly attribute the answer to the person who is speaking. I will also invite this person to turn on

8

their video, but this is optional.

To facilitate a more orderly and organic information exchange and discussion, we will use the time-honoured practice used to facilitate classroom discussion, physically raising a hand. If the consultant wishes to respond to a question or provide remarks, please indicate so by physically raising your hand once the person who is speaking is finished. We will then select the speaking order.

If a consultant wants to agree with something that has been said by someone else, I ask that you limit your remarks to stating your agreement and only add what is necessary to supplement the information that's already been provided. In situations where more than one of the invited consultants wishes to respond to the remarks made by another, I will do my best to select the order of responses in a random fashion.

During the questioning, Commission Panel members or staff may have related or follow-up questions. They will communicate this to me, so as to minimize any disruption to the flow of the discussions by raising a hand, either virtually or through a private message -- sorry -- virtually through a private message or physically. At an appropriate time, I will invite that Commission Panel member or staff to ask their question.

9

The four invited consultants will have their video turned on for the duration of the discussion, but with their audio muted unless they're speaking.

The Commission members and myself will also keep our videos turned on, together with our court reporter, so she can promptly intervene if she needs to. Staff will have their video turned off when they are not asking questions.

For those of us whose cameras will be on for the full day, should any of us appear distracted, rest assured that we are taking notes or viewing meeting-related materials on a second monitor or a hard copy. If an actual distraction arises for any of the participants that are screen, we ask that you temporarily turn off your camera for that time.

In situations where Commission members or staff wish to pose a question to a representative, other than the four individuals from the consultancies, we'll invite a representative from the party to indicate if you are on the line. You can indicate that you're on the line by selecting "raise your hand" function at the bottom of your screen on Zoom. Once you "raise your hand," a videoconference organizer will note it and turn you from an "attendee" to a "participant." This will disconnect your feed briefly for 3 seconds and

10

immediately reconnect, at which point you will be able to unmute yourself, turn on your video, and respond to the question.

To make the most effective use of everyone's time, I may step in as moderator when someone is going off topic in their answer or providing more detail than is required. If I do step in, don't feel bad about it. We're talking about very interesting topics and things can get carried away.

Another situation where I may step in as moderator is when we need to move on from a topic. We likely do not have time for all representatives of the four consultant groups to respond to or comment on every question. In these cases, the option of submitting written concluding remarks is available to all parties should a party wish to respond to an answer that is provided in the course of this virtual meeting.

I may also step in if the court reporter, or others, are having technical difficulties.

To step into the discussion in my role as moderator, I will do so by initially using a visual cue of raising my hand, and then speaking. These visual and verbal cues may also be used by the court reporter, Ms. Gerbrandt, and Commission Panel and staff.

Today's discussion will primarily focus on three

11

topics as previously communicated; however, we have reordered the topics.

So the first topic will be on rate design and dynamic pricing; the second topic will be advanced metering infrastructure and access to data; the third data will be a more general discussion, particularly on the next steps following the inquiry.

There are scheduled breaks throughout the agenda, being largely unchanged from what was communicated in Exhibit 680. So our first break will begin roughly at 10 a.m.

A further point of order is the definition of distributed energy resources, or D-E-R-S, or DERs. Module One revealed there's no subtle definition of DERs. To be as inclusive and comprehensive as possible, Commission staff and Commission Panel members, at least in the context of this meeting, adopt the National Association of Regulatory Utility Commissioners definition of DERs. Namely: (as read)

"A DER is a resource cited close to customers that can provide all or some of their immediate electric and power needs. It can also be used by the system to either reduce demand or provide supply to satisfy the energy,

12

capacity, or ancillary service needs on the distribution grid. The resources are generally small in scale, connected to the distribution system, and close to load. Resources included in this definition are solar PV, combined heat and power, energy storage, demand response, electric vehicles, and energy efficiency."

There is much ground to cover and we are limited in our time.

I now invite and welcome our four lead consultants: Mr. Friesen of InterGroup Consultants; Dr. Faruqui of the Brattle Group; Mr. DesLauriers of Charles River Associates; and Dr. Orans of E3.

I will now turn it over to Randy Lucas, who will lead us in our first set of questions on rate design.

MR. VAN EGTEREN: Just before we jump to Randy for those questions, I just wanted to check with the transcriptionist -- I hope that's correct -- and determine whether or not Mr. Reese's pace was sufficient for you.

COURT REPORTER: Yes, it was fine. Thank you for checking. But I found the Chair was hard to hear at times. I don't know if his microphone is close enough.

13

MR. VAN EGTEREN: Okay. Thank you, Ms. Gerbrandt. We'll make sure that Mr. Romaniuk has his mic appropriately located.

MR. LUCAS: Thank you, Mr. Reese.

D. FRIESEN, A. FARUQUI, D. DESLAURIERS, R. ORANS
THE COMMISSION QUESTIONS THE PANEL:

MR. LUCAS: Welcome, witness panelists. As Commission Member Romaniuk mentioned in his opening remarks, the purpose of the inquiry is to begin to determine the regulatory framework necessary to accommodate DERs and the possible evolution of utility distribution systems.

Starting with Mr. DesLauriers, can you please describe for me how you see utility distribution systems evolving to accommodate the changes to the grid that you see coming and the regulatory framework necessary to accommodate that evolution?

MR. DESLAURIERS: Sure, I would be happy to. Good morning, everybody. David DesLauriers, Charles River Associates.

As we know, the impact of DERs has a tremendous influence on how distribution systems will be changing over the coming years and coming months. We see today that we are evolving from a one-way system, where,

14

under traditional architecture power is flowing from a generation source over a distribution and transmission system to end customers, and it's essentially a one-way and, if you will, highly regular flow in the sense that demands are pretty well understood, energy flows are understood, through measuring and load profiling, but it's essentially a one-way direction. That's obviously changing now as we have two-way flows coming from the influence of DERs.

And so that leads to a host of operational considerations that need to be managed with intermittent power flows. There are regulatory and tariff considerations to be considered as we have addressed in our report related to the tariff mechanisms for DER to, in particular, residential, small customers.

And so I think the -- you know, the need for distribution systems and regulatory oversight of distribution systems continues to be there. As we outlined in our report, we believe that rates continue need to be cost causative. I think that regulation continues to be a necessary oversight to prevent cross-subsidies in rate application and tariffs that might occur from DERs.

And there's obviously greater incentive and need

15

for new technologies to come onto the system, including energy storage, electric vehicles, larger scale DERs. These are all providing additional innovations and value to consumers and opportunities to reduce the overall cost on the system. And so I believe regulation has a role to play in that in helping utilities foster that innovation as well as to receive reasonable and fair rate recovery.

MR. LUCAS: Thank you, Mr. DesLauriers.

Does anyone disagree with Mr. DesLauriers' response or have anything to add to his remarks?

MR. FRIESEN: This is Mr. Friesen, or Dale Friesen, from InterGroup Consultants.

I would strongly support the nature of Mr. DesLauriers' comments and agree with them.

I think, when we look at the three primary influencing factors, which are commonly referred to as digitalization, carbonization, and decentralization, we really have to look at how each of those is changing the nature of the grid in a forward-looking fashion.

We will enter an era where information becomes plentiful, and we will need to learn to use that information in a productive and efficient manner to improve the grid and reduce the costs.

Decarbonization is going to change the nature of

16

how we use electricity and produce electricity considerably.

You know, we're all aware of the growth in the photovoltaic market and renewable energy and how that is creating a move away from centralization generation towards decentralized generation. Consumers for the first time will be very actively involved in the production of energy for their own use and for use by grid customers at large.

We're also talking about a tremendous shift in energy consumption, transportation being a prime example of that and, you know, we're running a balance here.

If we look at traditional load consumption, we're seeing either stagnation or a decline in load, which may be offset by some of these shifts in use to transportation and other means, electrification of heating, et cetera.

But I think the aspect of tariff design that will be most profoundly impacted is through decentralization. And how we examine tariffs for production that are uniform, non-discriminatory between transmission and distribution, will be a particularly challenging item when we look at the nature of the changes that decentralized generation will force onto

17

the distribution system with their variability, and, you know, they generally do not have the same dispatchability as centralized generation, and those aspects are going to have a significant influence on tariff design. Thank you.

MR. LUCAS: Thank you for those added comments, Mr. Friesen.

So you both mentioned tariff design and cost causative rate, so now that we're in the Combined Module, let's move to the rate design, shall we?

So, in IRs, we discussed balancing several competing objectives in rate design.

On the one side, collecting the embedded cost of the existing infrastructure and the utilities approved revenue requirements suggest to some the need for a rate design that contains more fixed charges. Further motivation for additional emphasis on fixed charges may be caused by the incumbent utility facing, or expecting to face, increased competition and bypass.

And when I refer to "bypass," I'm referring to both economic bypass, which lowers costs to society, and uneconomic bypass, which lowers costs to the individual customer but raises costs to society.

On the other side of the balancing act, customers

18

should be subject to price signals that allows them to make decisions that would lead to economic, efficient outcomes in the long run for both themselves and the amount of infrastructure required to serve them. This may argue for a rate design to retain some form of variable charges.

The Commission asked each of you to connect -- excuse me -- to comment on the rate design that would achieve such a balance.

Before I proceed with my questions, my detailed questions, are there any additional comments or observations you would like to add to your written recommendations?

All right. Seeing no hands, I will move to my more detailed questions.

So, first, I want to focus on volumetric charges as an element of efficient rate design, and then we will later move to discussing demand charges, and then, hopefully, we're able to cover most of that before the break; and then after the break, we're going to move to discussing dynamic pricing.

So I'll start with you again, Mr. DesLauriers.

The three-part tariff that you recommended has fixed demand and volumetric charges. We heard from many parties in this proceeding that distribution costs

19

are nearly all fixed.

What purpose do volumetric charges, as in dollars per kilowatt hours, serve in modern rate designs, particularly, if the goal is to pursue economic efficiency?

MR. DESLAURIERS: Well, I think it -- as we stressed in our report, we think that underlying all rate design considerations is cost causation that we believe rates should be designed so that they have a close tie to cost causation and they communicate proper price signals with relation to cost.

That said, we also know that there are non-cost considerations that need to be considered, including gradualism, affordability, bill impacts, ease of administration, understandability of the tariff itself.

But as we step back and look at the cost construct of traditional utility distribution systems, and this construct hasn't changed with the imposition or the existence of DERs, they're fundamentally primarily fixed-cost base systems. And I believe that we stressed that and others that submitted reports in this proceeding have as well.

So to the extent that we recognize that distribution systems are fixed-cost systems, from a cost causation point of view we believe that

20

demand charges are an appropriate way to align recovery of costs with fixed costs.

With regards to variable costs, there are variable costs on the system, and we understand that there are variable O&M costs that change with the amount of energy that's sold, either exported or imported on the system, as well as energy-related costs that have a variable component. And that component really is variable due to the cost of fuel and the mix of generation resources that are being used any time on the system. And so there really is a time-based component and a variable component to a piece of the cost structure. And that's where we believe variable costs come into play and where there's a cost causative link.

And so to the extent that DERs can be considered as replacing higher-cost generation supply at certain points of the day, there is value to communicate that price signal through the variable rate in the tariff design.

And so in our recommendation we haven't excluded the use of the variable rate. We've in fact included that. But our recommendation is to -- to the extent possible, have that variable rate set so that it closely mimics the cost of that energy.

21

With DER, for instance, as solar -- for the example of a solar foot PV facility, when a facility is generating electricity, in effect, the centralized dispatched generation resources are saving on fuel, if you will, they're avoiding fuel costs, and so that does have a very significant influence on the value of that energy at that point in time.

Does that answer your question?

MR. LUCAS: I think so.

So it sounds like you're connecting this volumetric charge to O&M costs, particularly the cost of fuel.

So I want to direct a question at Dr. Orans. You also recommended a three-part tariff with a volumetric component, and I believe you said that the energy component should correspond with the cost of providing the energy and, ideally, has a time-bearing rate that reflects the time-dependent cost of generation?

So in your recommended rate design, and in the context of Alberta's unbundled environment, is the volumetric charge component you're referring to suitable for collecting any of the distribution tariff, as in, the distribution and transmission wires cost billed to the final use customer? Or is it just for capturing the cost for generation?

22

Sorry, Dr. Orans. I believe you're muted still.

DR. ORANS: Sorry. That's a good question and a difficult question to answer. I'll do my best to see if I can bring some clarity to that issue.

I don't disagree with Mr. DesLauriers' characterization that the -- most of the costs in the distribution system for a time frame we're considering, less than 10 years, less than 20 years, a relatively short time frame, are operating and maintenance costs and perhaps some distribution costs, mainly related to energy losses.

You can talk about load factor and efficiency, et cetera, but most of the costs in the distribution system, over a relatively short time frame, within three years, let's say, let's define our incremental costs over that period, because if we say it's long enough, everything is variable. Remember, everything -- if you say it's fixed, you know, you can't have fixed forever; right? If I say the time frame we're looking at is 50 years, everything becomes variable; right? The whole system can be replaced.

Let's talk about a practical time frame where we're looking at substitutes for the distribution system. I would agree most of the distribution system is fixed, the operations and maintenance is potentially

23

a little bit variable, not entirely variable, and certainly losses are variable, potentially by time variation.

That's not to say -- and we're going to move, I know, to fixed charges -- that you can't have time-varying fixed charges to reflect some of those differences in the opportunity cost of service by a time period.

MR. LUCAS: Thank you, Dr. Orans.

MR. REESE: Sorry, I see Mr. DesLauriers has raised his hand.

MR. LUCAS: Thank you, Mr. Reese.

Please, Mr. DesLauriers.

MR. DESLAURIERS: Thank you.

I agree with everything that Dr. Orans said. I think, to put some perspective on my comments, I was speaking within the traditional regulated rate environment where there is typically a test year of about 12 months, there may be some pro forma adjustments of known and measurable changes outside of that test year; but within, as Dr. Orans points out, within the shorter time frame in which rates are typically set in a regulated environment and they are set on an embedded cost approach where there is a dollar amount, revenue requirements that is to be

24

recovered from rates, to recover the cost of a distribution system that are primarily fixed, I think we do need to consider demand and energy rates together, particularly with regards to the three-part rate design.

Under a traditional full requirements rate design without solar PV, to the extent that you have a lot of distribution costs, fixed costs recovered from a variable charge, that may not result in significant cross-subsidies among customers.

However, when we look at a typical, let's just say, for example, a net metering approach, where there's a one-for-one offset at the full cost of the retail delivery charge, when we don't change the allocation of recovery of costs from the energy over to a demand component, what happens is you do have some significant uneconomic bypass, as you pointed out at the beginning of the question, where you have costs that are not being recovered from a certain set of customers, and that, under a -- you know, a net zero rate design where all costs need to be recovered in that test year creates subsidies to non-participating customers.

MR. LUCAS: Thank you. Just to clarify one of your last points, Mr. DesLauriers, did you say that

25

moving from energy charges to a demand -- a higher emphasis on a demand component may lead to uneconomic bypass or subvert uneconomic bypass?

MR. DESLAURIERS: May avoid economic bypass for customer requirements --

MR. LUCAS: That's what I thought --

MR. DESLAURIERS: -- sorry.

MR. LUCAS: No problem. I just wanted to make sure I got that right.

So, Dr. Orans, you mentioned the idea of losses, so I want to keep that idea, but I want to put it in the parking lot for a moment and I'm going to return to it after the break. Okay?

MR. REESE: Randy, Dr. Faruqui had raised his hand.

MR. LUCAS: Okay. Please. Thank you, Mr. Reese.

Dr. Faruqui?

DR. FARUQUI: Thank you. I wanted to make a couple of comments about rate design.

But before I do those, let me indicate that, as a customer, I satisfy just about all the requirements of being a DER. DER sounds like a horrible curse word, and that's what our industry specializes in.

But, basically, the better word is "prosumer" and

26

the more advanced term now is "prosumager." So prosumager is a customer with solar, with battery storage, and, of course, an efficient consumption cycle, and then you add to it an electric car. So I have all of those. I just wanted to make that statement. As a customer, I thought it was important to adopt all these new technologies just to see what is the other side of the coin.

The term "uneconomic bypass" or "economic bypass," those terms are utilities speak, regulatory speak terms. The customer ultimately cares what their total bill is, and you can alter the rate design up to a point, whether the price of electricity is high from the grid, they're going to go and do what they can as a customer to lower their bill. Those are the realities down the road.

In the near term, there are subsidies that arise when a prosumer becomes a net zero customer and is on a volumetric rate, which is true in much of the globe. Distribution rates are largely volumetric with a small fixed charge.

If you look at the cost structure of the distribution grid, in just about every case that I have worked on around the globe, the distribution costs are largely fixed, with one utility estimating them as

27

98 percent fixed, there's Commonwealth Edison in Chicago, and others estimating it as upwards of 85 percent. So volumetric rate doesn't make any sense for recovering a cost structure for distribution that is largely fixed.

I support three-part rates, I have written articles on them, I have testimony on them. But the third part, the volumetric part, is for energy and not for distribution costs.

I believe the ideal distribution rate would have a fixed charge and a demand charge. What we have today is a very small fixed charge for most utilities and a very large volumetric charge, and that leads to inefficient decision-making by the customers.

So the ideal rate, at least as far as I'm concerned, for distribution grid is a two-part rate: Fixed charge and a demand charge, where the combination of those two depends on the cost structure of the utility.

All of the conversations about efficiency have to do with energy, and, therefore, they have to do with the energy charge, and we can come to that later on, but I just wanted to clarify that I have a polite disagreement with the other two experts on the issue of applying three-part rates to distribution pricing.

28

MR. LUCAS: Thank you for that clarification.

So before I invite you, Mr. Friesen.

So, Dr. Faruqui, I'm familiar with the term prosumer, but you introduced a new term that I've never heard before.

Can you spell that for, not only myself, but Ms. Gerbrandt and her transcription, please?

DR. FARUQUI: Yeah, I hope I get the spelling right. I need to have it in front of me. There are actually books now on the subject.

P-R-O-S-U-M-A-G-E-R. So storage is the ending part. So it's prosumer plus storage, and it becomes prosumager, but I can follow up with an email to pin it down.

It's sort of basically combining storage and battery storage could be as a separate battery in your garage or it could be in your electric car, it's that combination.

MR. LUCAS: It looks like my colleague Mr. Bourque wants to follow up as well, so I'll give him the floor and then, Mr. Friesen, we'll give you time to say your views on volumetric charges.

MR. BOURQUE: Thank you very much, Mr. Lucas.

I wanted to test the idea. With regards to wires recovery, having volumetric charges, in the preliminary

29

IRs, the Commission asked questions with regards to the avoided cost.

So if wires are being recovered via volumetric charges, is that not an avoided cost signal to become a prosumager and not just the avoided energy costs, but now you're helping avoiding the recovery of the wires through those volumetric charges?

DR. FARUQUI: Was that a question for me?

MR. BOURQUE: That was a question to anyone, and I saw Mr. DesLauriers also raise his hand, so --

DR. FARUQUI: Okay. I'll just give a quick response.

Absolutely, I agree. And that's why we should have demand charges, so if the customer reduces their demand and all they have is a fixed charge, they cannot lower that. They cannot look forward for reducing the cost of the wires. But if they reduce the cost of the wires by lowering their demand, then they should have a lower demand charge and a lower bill as a result of that.

So I believe a demand charge promotes efficient utilization of capacity as opposed to efficient utilization of energy. The energy portion, in my view, doesn't belong in the distribution charge.

MR. BOURQUE: Thank you very much.

30

Mr. DesLauriers, you had a follow-up as well I saw.

MR. DESLAURIERS: Thank you. I just want to respond directly to your question.

I believe the question was, does the use of energy charges to recover distribution costs not permit customers or does it permit customers to avoid any distribution charges. Was that the question that you stated, Mr. Bourque?

MR. BOURQUE: It was more, I believe, related to the recovery of the wires and, as an avoidable cost, being the volumetric charge --

MR. DESLAURIERS: Sure.

MR. BOURQUE: -- that it is a signal of some type of bypass, whether economic or uneconomic, or the potential for that.

MR. DESLAURIERS: Well, if we start with the assumption that distribution costs are a sunk investment today, that they are costs that are spent to build and maintain the distribution system, those are dollars that are, if you will, sunk, in effect. You know, they're not unavoidable by the utility to the extent that they are dollars that are invested in serving today.

In terms of price signals and giving customers the

31

ability to change their consuming behaviour to offset potential future costs of the system, I don't think the use of a flat energy rate, for instance, the style that is predominantly used in residential tariffs today in North America really give customers the proper signal because, in effect, they're being charged the same unit rate for an energy purchase from one time to the next and it doesn't necessarily reflect where scarcity is on the distribution system in terms of potential deferral of future costs.

So I agree with Dr. Faruqui that demand charges are probably a better way to deliver that signal than an energy-only charge today.

But I think in terms of the concept of avoided costs, we have to think of them for distribution system, really, avoided costs are future-looking, that distribution systems today that are operating are reflective of costs that are already incurred and won't be avoided in the future unless certain transformers, parts of the system are retired.

MR. BOURQUE: Thank you very much.

I see Dr. Orans, you have a follow-up, and then I wanted to turn and continue with the questioning that Mr. Lucas had for Mr. Friesen.

So, Mr. Orans, thank you.

32

DR. ORANS: If I could just add a little bit very quickly to something Dr. Faruqui mentioned.

So I agree with the concept that most of the distribution system is fixed. You build it, you build it based on connective load, and then not much is saved based on energy consumption. Perhaps with smart charging in a new world, you can avoid some future costs.

And if you agree with Dr. Faruqui's 98 percent or 95 percent or 90 percent of it being fixed, that's not to say, in a few areas in the distribution system, there are potential needs for upgrades and an opportunity to defer those.

So I want to make sure the Commission doesn't come out of this saying, "All costs are fixed in the distribution system everywhere all the time."

On average, for a standard, non-geographically differentiated rate, that is true, generally costs are fixed once the loads are there, but there are areas that change over time that have avoidable costs due to new upgrades.

MR. BOURQUE: Thank you for that additional follow-up.

Mr. Friesen.

MR. FRIESEN: Thank you, Mr. Lucas. I want to

33

echo and confirm a lot of the comments that were provided by the three independent experts. We concur, I would say, generally with most of those.

I did appreciate in particular the customer centric perspective that was provided by Dr. Faruqui. It really is an important perspective to understand, in that we are trying to promote cost-effective behaviour, and it's impossible to promote cost-effective behaviour without price signals that customers can respond to.

So when we specifically address the volumetric component of a distribution rate, I think we do have to consider that there are some variable components. You know, roughly 10, maybe up to 15 percent, depending on the nature of the grid, of energy consumed by consumers is lost through transportation, through the grid. And there's an opportunity to use the volumetric rate to reflect that cost of lost energy in the distribution system, and we shouldn't ignore that opportunity.

I also want to speak a little bit to the concept of diversity. The further back you go into the distribution system, the more reliant our capacity sizing, our capacity accommodations are dependent on diversity. There's tremendous diversity within consumer behaviour, and when we lose that diversity, we create peak loads.

34

And if we -- if we send price signals -- and capacity price signals are probably the most appropriate way of doing that -- to consumers that they can respond to, I would argue that we're providing a forward-looking price signal to customers that will affect or influence future costs incurred by DFOs.

Yes, DFOs have some costs, and those create a fixed-cost environment, but we still need to appropriately allocate those costs to the consumers that are driving the peaks, and a capacity charge does that much more effectively than a fixed charge can, which views customers indiscriminantly, or at least indiscriminately within a rate category.

So I think it's very important that we recognize the role of diversity in the design of the distribution system, and we look at ways to maximize that opportunity for the purpose of reducing capacity requirements on the grid, and we have many new technologies entering the market such as electric vehicles, such as storage, et cetera, which can be used to maximize that diversity and, therefore, decrease the fee. Those are opportunities we should explore to their fullest and we shouldn't ignore.

Finally, I want to speak to the issue of economic or uneconomic bypass. I think the point was made, that

35

is a DFO term or a utility term, and I would agree strongly with that characterization.

If a customer, through the implementation of technology is able to move away from certain services that the utility provides -- so if they choose to make a decision in respect to reliability, and no longer depend on the distribution system for reliability, in my view, that is not "uneconomic bypass."

I think we have a tendency in the industry to characterize "uneconomic bypass" as any bypass or any avoidance of charges that are applied through tariffs. That is an unfair characterization of consumer behaviour.

I think consumers, at the end of the day, are willing -- are seeking to manage their energy bills and do so in a way that is as unfettered as possible, and if they are able to minimize their use of certain services from the utility grid, they should not be charged for those services if they're not utilizing them.

So let's be very careful in how we characterize "uneconomic bypass." I think it's important that we all have a clear understanding of what we mean by "bypass" and "uneconomic bypass" in particular.

Thank you.

36

MR. BOURQUE: I believe my colleague Mr. Lucas had a question and a follow-up.

MR. LUCAS: Yes. So, thank you, Mr. Bourque.

Mr. Friesen, you talked quite a bit about bypass, economic bypass, or uneconomic bypass.

So are you, in effect, disagreeing with Dr. Faruqui's characterization of thinking about bypass in terms of social costs? Or are you more in alignment? I didn't quite catch it.

MR. FRIESEN: Thank you, Mr. Lucas.

No, I'm not disagreeing. The point I'm making is that, no matter what technology we're talking about, we've seen tremendous evolutions of technologies across many sectors of consumer use, and industry has had to respond to those changes in technology.

And the utilities network is no different. While they are a regulated entity, and while we have ascribed certain responsibilities to them, and as a result of that, we've provided them with certain guarantees in respect to cost recovery, we cannot use those guarantees as a way of subverting changes in consumer behaviour. Consumers are at the top of the food chain, really, in many respects, and industry has to adapt to consumer behaviour.

So when I'm referring to "bypass," I recognize

37

that consumer technology adoption may result in economic bypass. I hesitate a little to refer to all of that bypass as "uneconomic."

Some of it is a result of change in technology, change in behaviour, that the industry simply needs to adapt to, and that means there's some risk in the equation for industry and they have to accept that risk.

I think, fundamentally, that was the point I was trying to make.

MR. LUCAS: Thank you.

I would now like to move on the discussion towards focusing on demand charges. It's something each of you talked about moments ago, as well as in your written submissions.

So I think there's a lot of different, call them "flavours" of demand charges out there, based on system peak, like your own capacity demand during system peak, your own absolute peak, is there a ratchet, unratcheted, is that charge flown through for a month, a year, two years, how durable is it.

So I would like, maybe starting with Dr. Faruqui because you only suggested a two-part tariff for recovering distribution costs, what kind of demand charges you had in mind as your ideal demand charge?

38

DR. FARUQUI: Sure. So it comes in many flavours, and I hesitate to say one of them is ideal. So let me first just briefly talk about the different ways in which demand charges are collected today.

So in Europe, for example, in France and Italy and Spain, they have a capacity charge. It's based on your connected load. And so if you have a bigger load because it's a bigger house, you pay a bigger capacity charge; and if it's a smaller house, you space -- and that's unchangeable, it's just hard wired, the size of your connection. That's been around for 50 years, you know, and longer, it's a post World War II innovation.

And it makes sense. It's sort of like, if you think of it in a particular house, you have a circuit breaker. You have a lot of circuit breakers. And if you have a big party and every circuit is on, at some point you're going to trip a circuit breaker and there will be darkness and very annoying to the partygoers. So then you have to go back, reshuffle the circuits and then turn it back on. So that's kind of a capacity charge, which nobody realizes until they trip it.

But the utility is saying, look, that's for your house, but we also have the similar capacity issue for transformers and, ultimately, feeders, circuits, and substations.

39

So how do we capture that. Well, we do it quite well for large customers. It's still the same system whether it's a large customer or a small customer. The grid is essentially the same kind of grid in terms of its cost structure.

So the ideal demand charge would have two elements: There would be a non-coincident peak element and a coincident peak element. The non-coincident peak element would be your demand regardless of time of occurrence, the maximum demand, because that's what, as the utility, we have to design the system to be able to make sure your lights stay on regardless of how much you consume. It doesn't matter what time of day it is because that transformer is there 24/7.

However, there are additional elements that arise in the equation when there's a coincident peak occurring on the distribution system, and that should be captured in a demand charge as well.

So a lot of the large customer -- C&I customer tariffs have both an NCP, or non-coincident peak, demand charge, as well as a coincident peak, or CP, demand charge.

The challenge arises when we deal with residential customers. Partly it is a metering question. They just don't have the metering to do it in many

40

utilities. And I believe that is the case in Alberta -- I could be off-base there, but certainly that is the case for ATCO Electric Distribution.

If you had the metering in place, then you could conceivably try to emulate the demand charge that you have for C&I customers. The question would be one of customer comprehension, understanding, and acceptance.

I've had several discussions on this topic at conferences with commissioners and utilities and stakeholders, and there is no easy consensus that I can point to to say that they agree that two demand charges are appropriate for residential customers.

The simple reason is, most of them don't even have a single demand charge today. So it's quite a leap of faith to go from no demand charge, as we have heard from the others, the charges in place today are largely volumetric for distribution cost recovery, along with a fixed charge.

Alberta has higher fixed charges than I have seen in many other jurisdictions in the US, some have fixed charges of zero. That's California, for example. Some have fixed charges of $20 and some have $40, but by and large, the issue is, if you are going to introduce a demand charge, can you even think of introducing two, and most people say no, you can't, for residential

41

customers. So let's be realistic, and so then it will be a single demand charge.

So if you look at the US, for example, we have about 70 demand charges being offered today to residential customers across the country. Most of them are non-coincident peak, it's that maximum load in the month regardless of time of occurrence.

But some of the more, let's say, innovative rates are the ones you see in Arizona, the APS and SRP, and they have a peak period definition, five hours to six hours, it's the highest demand in that window of time.

So there are many flavours of demand charges, and each one has to reflect the competing principles of rate design, one of which is cost reflectivity, which would argue for the two demand charges I was mentioning, maybe even three, with the capacity charge being one element, and the notion of simplicity and gradualism.

So there is no consensus today on what is the best way to start when you don't have a demand charge to begin with. I think it requires a stakeholder conversation, it, of course, requires the right kind of metering; but, ultimately, I would say, throughout the globe, including New Zealand and Hong Kong where I'm working on these issues, you have to begin to move in

42

that direction. It does not make any sense to have a volumetric charge for distribution.

The other point is how do you measure demand. Is it over one hour? Is it over half an hour? Is it over 15 minutes? And, again, if you look at the commercial and industrial demand charges, they tend to be, in many cases, for 15 minutes. Many people have argued, including the hearings I have been in, in Arizona, for example, that's too difficult for a customer to relate to.

So I would say, to summarize, probably a one-hour definition of demand, where the demand charge is collected for a peak period that you define based on the distribution peak considerations. I think that might be the most practical way to look at it.

MR. LUCAS: I believe Ms. Collins had a follow-up question. I received a note from her.

Ms. Collins.

MS. COLLINS: Thank you, Mr. Lucas.

Yes. Just when we were on the -- I was interested to hear Dr. Faruqui's discussion of ideal design of demand charges with an NCP component and a CP component.

And I know there's been a lot of discussion around ratchet, and ratchets, are they fair, are they needed.

43

Is that an integral part of an NCP component in your view? Could you speak a little bit to the merits of a ratchet. Thank you.

DR. FARUQUI: So, great question.

And I would say ratchets traditionally have been part of commercial and industrial demand charges. The residential demand charges, I am familiar with the 70 or so that I mentioned. I don't believe any of them have a ratchet. I would have to double check it to be exactly sure, but, certainly, the more prominent ones don't have a ratchet. And ratchets have acquired generally a bad reputation in the industry, even for C&I customers, they are under attack, I don't know how long they will survive.

I would think for residential distribution demand charges, a ratchet is probably not needed. I wouldn't recommend it, because even if you do not have a ratchet, there's going to be a lot of opposition to introducing demand charges, even of the simplest kind.

The objections would be people don't know what demand is, people won't know how to respond to it. What if a soccer mom brings her kids home and they all take a shower at the same time. Those are all the issues that are going to be encountered, there are answers to all of them. There are successful examples,

44

like in Arizona, where you simply say to the customer, here are your five major appliances, don't run all of them at the same time.

So there are very simple ways of messaging, what is demand and how to manage it, but introducing a ratchet is going to create, I'm going to call it a "scarecrow effect," and it's best avoided.

MS. COLLINS: Thank you. That's very helpful.

MR. REESE: I'll just point out that we're now at 10:00, which is the time for our scheduled break. So I'll put it to Commissioner Romaniuk if you would like to continue?

THE CHAIR: Thanks very much, Mr. Reese. I think, in fact, we should stick to our scheduled ten-minute break and return at, let's make it 10:12, if that's okay with everyone -- 10:12 Alberta time.

I'll leave it to everybody else to work out what your time zone is in and what that translates into.

Thank you.

(ADJOURNMENT)

THE CHAIR: I'll turn it over to Mr. Reese again.

MR. REESE: Thank you, Commissioner Romaniuk.

Randy, would you like to continue your questioning?

45

MR. LUCAS: Yes. Thank you.

So thank you for your comments before the break, Dr. Faruqui.

So if we --

MR. REESE: Randy, could you please turn on your camera.

MR. LUCAS: Yes. Thank you. I remembered to unmute myself, but I forgot my camera.

So if we think about the cost of the system, so in my mind, I've been thinking about it in terms of embedded costs as one big bucket and then a separate bucket, but much, much smaller to the point you made earlier in terms of percentages of fixed and variable costs in the system, is this marginal cost bucket.

So we have fixed charges, they're going towards the embedded costs and, Dr. Faruqui, you're arguing that some or all of the demand charges that you're recommending would be going towards collecting the embedded costs as well, and my presumption, this is what I want to test, that would be the NCP portion of the demand charge.

And then is it fair to say that the CP demand charge would be this marginal cost -- fit with this marginal cost bucket, or would it also be recovering any of the embedded costs?

46

DR. FARUQUI: A great question, and clearly one that different experts will have different opinions on, even opinions that might change by the year.

But let me step back and address the broader question you have, and then I'll answer the specific one.

We all have discussed in the last hour that there is both the issue of the short run (phonetic), in which cost recovery is paramount for the utilities to stay in business, but also the fact that systems grow with time, new loads come in, new challenges come in.

I think it was mentioned by the CRA experts that there is the issue of, you know, turnover that has to occur, new growth occurs. It's a balancing act.

I think Dr. Orans did some pioneering work earlier in California on using DSM to avoid distribution upgrades -- I might be misquoting it, but I'm sure he'll correct it -- but it was certainly one of the early studies to show that distribution investments could be avoided using customer-side resources.

More recently in New York, Con Edison has had this project for a while, to avoid upgrading a big distribution substation which would cost a billion dollars, they're avoiding that by investing $200 million in DSM.

47

So there are avoidable elements of distribution costs, even though the first response is to say it's entirely fixed, but it is fixed currently; but as you look at the future, as growth occurs, or even as growth doesn't occur but you have the two-way grid being created, you will need to invest in new distribution upgrades to accommodate these challenges. That's a marginal cost element.

And so what I was thinking of was, for a customer -- let's imagine cases A and B. Case A is they just have a fixed charge for distribution. They cannot do anything to avoid it. $50 a month or whatever the number is. Well, that's, I believe, not a very efficient way to look at it as a progressive forward-looking way.

So that's why I'm saying we have to combine it with some element that the customer has some control over, so that if they were to control the growth in their load, then the distribution grid wouldn't have to make all those investments that otherwise it would have to make.

So there is a progressive, forward-looking element to the demand charge, and that could be the CP element or you could even formulate the NCP element to be forward-looking. It's just a question of which

48

philosophy you have.

But if you have just a fixed charge, the customer cannot do anything. And that's all embedded costs for lost fee at work. Even with an NCP demand charge, the customer can lower it. They can lower it by not running all their appliances at the same time, being sensitive to demand as a metric as opposed to just energy as a metric.

So it can promote efficiency, but with CP, you're now more targeted. You're looking for particular times of day when the distribution grid is peaking and you're trying to avoid upgrading the transformer.

Take the case of electric cars. I know in Alberta, the penetration is relatively low, but it is picking up fast throughout the globe, and in about ten years, a lot of car companies won't even make conventional cars -- I think that's a well-known fact.

So it's very clear that if a lot of people in a cul-de-sac were to get some kind of a Tesla, let's say, then suddenly there will be a huge strain on the transformer that feeds those houses. That will have to be upgraded. How do you collect the cost of that? It's a marginal issue.

You can do a time-of-use rate. But if you're just a distribution utility, can you do a time-of-use rate?

49

Yeah. I mean, if you are going to stick with a volumetric rate and you cannot put in a demand charge, then you're going to have a time-of-use rate for distribution.

And that's what I cite. I cite two examples of that in my report, one in New Zealand and one in Australia; and then more recently Con Edison has introduced such a rate as well, for the distribution only portion of it.

So it's a philosophical issue. Being an economist, I'm not an accountant, but I've talked to enough accountants, including my wife, to know that there's a need for cost recovery in the short term for companies to stay in business. So you have to have a blend of the two.

MR. LUCAS: Thank you.

So, Dr. Orans, I want to ask you a similar question.

In your recommended three-part rate structure, the main function of the demand charge is to collect the embedded cost of service and not to send an efficient price signal? Hopefully, I got that right.

So, if that is true, then which part of your recommended three-part tariff would send that price signal?

50

DR. ORANS: First of all, I want to say, I agree with almost everything Dr. Faruqui said. So we're totally in alignment, and I think this distinction between a two-part and three-part is a difference without any significance.

We agree that basically you have two goals: You want to collect the revenue requirement, the fixed costs, and you want to do that in as safe a way as possible to keep the risk down to the basically owners so that they don't have a high cost of capital.

So it's a distribution monopoly, natural monopoly still; it's contestable in some parts, so you want to allow efficient expansion and alternatives to flourish; but, largely, you want to keep the fixed charges as non-bypassable -- difficult to bypass as possible.

At the same time, you want a piece that's variable. So we would say the fixed charges, to come back to your direct question, could be NCP, as Dr. Faruqui said.

I'm not so hung over on whether there is a ratchet or not. If a ratchet helps you make it more fixed, I'm okay with that. Many utilities still have ratchets in their demand charges, so NCP with ratchets.

I would also argue there's a place for customer charge, whether that's a minimum bill or a customer

51

charge, there's some fixed costs that are reoccurring that have nothing to do with load spikes. There's some variable O&M and there's certainly distribution losses. That could be in the fixed charge or the distribution losses, and the variable O&M could go into a variable charge. Either one, I don't think that is a big distinction either. That is why I think the two- and three-part rate are similar for distribution.

Variable -- I also agree with Dr. Faruqui, you could have a time -- if you wanted something relatively simple, you could have a time-varying form of a CP charge. And you might want to make that more complex and more dynamic and more updating. The larger the customer and the more understanding and the more ability they have to react in understanding and consume it, if you will. Simpler if they have less.

MR. LUCAS: So this notion of a CP charge for demand tariffs, can we talk about that a bit?

Because I'm familiar with the concept in terms of, say, our ISO tariff and when it bills at the POD level, but given that the distribution system is often a collection of separate feeders, there's no -- as my non-engineering understanding goes -- there's no coincident peak on a utility's given distribution system per se, but maybe on individual feeders. So how

52

do you take that into account when you design a CP?

DR. ORANS: So I wrote, actually, a doctoral dissertation on this very topic. So I am probably the world's expert on defining an incremental avoidable cost in a distribution system, and it's been used in multiple places.

So you need to find -- you need to define what we call a distribution planning area. That is where loads and investments are causally interconnected. So that is, under normal operations, the open and close switch positions define the loads served in that area and the investments connected to it.

So let's just take Dr. Faruqui's cul-de-sac idea. Let's say there are ten cul-de-sacs served by two distribution substations and eight feeders in that area, not the cul-de-sac itself, but the distribution planning area. In most cases, as Dr. Faruqui already mentioned, you will look forward for the practical, let's say it's three- to five-year time period, and there will be plenty of distribution capacity on that system. The time-varying, then, value of that distribution capacity, whether I'm charging on peak in that distribution area or off peak, is pretty much the same. There's not much distinction in that and you don't need to send a signal, other than losses perhaps;

53

right? But for collection of fixed costs and sending a capacity signal, it doesn't vary.

Now, if that cul-de-sac has a whole bunch of people across the eight distribution feeders, all with Teslas, all charging at the same time, you might have a problem. You want them to efficiently shift, modify behaviour. If the distribution company then has an upgrade that they would like to make, you can basically look at deferring that upgrade, put it in a capacity signal, charge a coincident peak charge for that distribution planning area that matches the incremental forward-looking costs in that distribution planning area. If you wanted to.

Now, this is a whole bunch of work, and if you go back to what we said in our roadmap, you know, I think you don't want -- if 99 percent of the distribution planning areas in Alberta look like the first case where they're not constrained, there are not enough Teslas, and other connected end uses that are substantially pushing capacity needs, then I think it's a lot of work to do to permeate that through all the distribution systems without much efficiency gain.

MR. LUCAS: Thank you.

MR. REESE: Dr. Faruqui has something to add.

Mr. DesLauriers, did you have something to add?

54

Your microphone is off.

MR. DESLAURIERS: I apologize. I didn't hear you.

I agree with everything that Dr. Orans said. You know, we do a lot of rate work and pricing work, cost-of-service work across the country, and there are a couple of -- you know, a couple of fundamentals that we recognize in that work.

You know, as you move down the voltage in a distribution system, down to, say, the transformer level and the end-customer level, there is less diversity than if you are enlarging that viewpoint in that planning area. And so, typically, in cost-of-service studies, we allocate costs on the NCP because that is what is the planning criteria to manage that lesser diversity.

And so we haven't seen a lot of CP pricing and a lot of usage for CP cost allocation within the residential class itself. We typically see CP used on the transmission system that drives those costs. So I just wanted to make that point that, primarily, we'd seek cost-of-service studies using the NCP to allocate costs down to residential customers.

And we agree with Dr. Orans. Right now, we're not seeing a lot of distribution systems with a lot of load growth, and that comes from our marginal

55

cost-of-service work. That doesn't necessarily mean that that won't be the case -- the case in the future.

MR. LUCAS: Thank you, Mr. DesLauriers.

So I want to go back to Dr. Orans' concept of a distribution planning area. So my presumption is it would be a smaller set within a distribution facility operator's service territory. So then there's this geographic element to it.

And you said that, for most of the time, and especially in Alberta, they're not bumping up against that kind of ceiling, as it were, to capacity. There's no cul-de-sacs that have 12 Teslas spaced up through various houses.

So my understanding is, then, it would keep that fixed element is what you're suggesting, and then when it gets close to that system peak capacity, then this dynamic element would start to kick in for that distribution planning area.

So how do you get that -- how do you have that charge lined up so that it will kick in when it's not needed now?

DR. ORANS: So in the IR responses, I find myself asking myself that same question when you asked it.

If there is a variable component, you know, in my

56

roadmapping concept, you know, would I ask the Commission to ask, you know, the distribution owners to basically start implementing this, and is this the pathway forward that makes the most sense?

I think before you get to that, you have to ask yourself -- let's go back to Dr. Faruqui's cul-de-sac example -- does time-of-use pricing or CPP pricing or real-time pricing solve the 11 Tesla problem in the cul-de-sac? The answer I think is clearly no. It's too -- it's not a durable substitute long term for distribution capacity.

That's not to say, Dr. Faruqui, that I disagree with you, that you could have a simple time-varying charge that would help those people efficiently charge off peak, those that can, and maybe the distribution upgrade is deferred partly or smaller, and there's a benefit to the prosumer and there's a benefit to everybody in that.

So you can have that as part of the roadmap, but I think you need also this alternative wire service kind of option idea where it might include a combination of pricing things and quantity-based rationing and distributed generation or micro-grid alternatives that compete with, basically, long-term distribution upgrades when we see distribution planning areas

57

nearing -- and you need to do this -- you can't do it within the year, you need to look at this in a multiyear time frame, because it's unrealistic to be able to go out for bid for a long-term, durable contracted source of capacity in a distribution system, you know, in a short time frame.

MR. LUCAS: So that question that you find yourself asking yourself that you put in IR responses, I actually noted that, and I noted your response where you said: (as read)

"The tariff can provide efficient short-run price signals mainly reflecting energy costs and losses..."

So we're returning to this idea of losses that I parked earlier this morning: (as read)

"...that are time varying, easy to implement and understand. The dynamics..."

You went on to say: (as read)

"...the dynamic time scale of the price signal can vary by class of service with smaller customers seeing relatively simple forms of time-of-use pricing and larger customers seeing more dynamically updated pricing."

58

So, to me, in your response, there are two elements: There's the energy costs and losses that might reflect kind of the dynamic -- or potentially dynamic portion.

And so if we just take the energy costs for a moment, and I guess still keep losses in the parking lot, so given Alberta's functioning -- has a functioning wholesale energy market, if retailers were required to recover the actual cost of supplying each customer with the energy they consume, as in the hourly wholesale price times their hourly consumption, instead of an hourly load profile that we currently use for most, if not all, customers, would this achieve or work towards achieving the objective of providing an efficient price signal?

DR. ORANS: I think, if I understand your question -- all of it, it's packed with a lot of different things -- I think if I understand it correctly, my answer is yes. If retailers, whether they're aggregations of retail loads or the loads themselves, see the short-run costs of loss and any variable cost in a distribution system, that's an efficient price signal.

MR. LUCAS: Okay. So then if we pick up the second component, the losses -- and in this case we're just thinking about distribution losses. So the paper

59

by the Council of European Energy Regulators that the Commission shared indicated that network losses can be recovered through marginal pricing such as volumetric hourly marginal losses -- pardon me -- such as volumetric hourly pricing.

Is it possible to design an effective price signal based on, let's say, distribution system losses approximated on the aggregate average losses for the entire system on a given hour?

DR. ORANS: It's an approximation. I mean, all of these are what I -- this concept of marginal cost is pretty useless, I think, for rate design, and especially when you're talking about small residential customers embedded in distribution systems.

So you're averaging over something. So it's an incremental improvement to have time varying over a single load profile losses for a distribution system.

And if you look at many ISOs in North America, that's exactly what they do. They don't really have a nodal loss. They have an aggregate average loss matrix that they apply to the gen wholesale load price to bring them down to the distribution level.

MR. LUCAS: So what I heard is, pursuing the distribution losses, then, may not actually be worth the effort in trying to add that into rate design to

60

create some kind of dynamic price signal of when your 11 Teslas on the block are hitting that system capacity?

DR. ORANS: Yeah, I'm going to come back to the roadmap idea. I think it's -- it's -- as Dr. Faruqui said, you know, it's a lot of detail for customers to understand right now, and the infrastructure necessary to do that is potentially expensive and could be obsolete by the time you get there in the roadmap. Basically, the latency, the signal, the automation, the interface, all of that is evolving quickly.

So I wouldn't encourage, basically, everybody to run out right now and dive in, you know, from this proceeding into that piece as a short-term recommendation.

MR. LUCAS: Fair, fair. But if we've gone to the trouble of installing AMI systems that could build based on demand as you recommended, then why not go the next step further and start having retail prices based on time of use and then add this distribution -- or, pardon me, distribution line losses component as well.

DR. ORANS: I have no problem with that. If you spent all the money on that and you've seen all the enabling conditions happen and all the triggers have

61

happened, then I have no problem with it, as long as what you're signalling are truly variable costs like we've just discussed in those, and you're not basically putting a big portion of the fixed costs in there as well.

MR. REESE: Dr. Faruqui, did you have something to add here?

DR. FARUQUI: Yes, just two brief comments, if I might.

Going back to the cul-de-sac example, that actually came up in a discussion with the city of Palo Alto about ten years ago when they were seeing Teslas proliferating and your neighbour got it, so you had to get it, et cetera, et cetera, and then they were a utility with no smart meters, lots of smart people living in Palo Alto, Stanford next door with no smart meters, so they were just saying, we hate these EVs. Well, too bad, customers are getting them.

So without AMI, you can still do certain things. You can have smart charging, you could have -- you know, most of these Teslas, and I'm sure most of these other cars, have the capability, if you have a smart charger, you can just stagger the charging times, and this is something the utility could control, with the agreement, of course, of the customer, they get

62

something in return for it. So that prevents you from having to upgrade your -- you know, distribution circuits around that cul-de-sac. So that's one point I wanted to make.

The other point I wanted to make is more of a practical point about locational variation in distribution pricing, which I know comes up a lot, but I have not seen any practical way of convincing customers that your rates are going to vary based on your location. It has been talked about with a lot of passion over the years, and IEEE at other conferences, locational-based, marginal-cost pricing, but I just don't know if that is the first priority that one shall have when trying to modernize rates. There is so much more that can be done without locationally varying the prices.

Now, you could provide other incentives that vary by location, you could certainly do that, But trying to vary rates by location, I think might be politically a very challenging -- and potentially, you know, a roadblock that may not be easy to overcome, and then the whole movement could be thrown away because you came up with too idealistic of a notion. So I just wanted to share that.

It's just sort of an observation based on

63

anecdotes, I cannot prove that is the case, but the proof is in the fact that it doesn't exist today, and the reason it doesn't exist today is because of the practical, almost unsurmountable difficulties.

Easier to deal with rebates that vary locationally, like the Brooklyn-Queens project in New York.

So some hybrid approaches might be useful to do than idealize locational marginal cost base pricing, especially for distribution.

MR. LUCAS: Mr. Friesen, I think you've been waiting patient to get in, and then I also noticed Mr. DesLauriers had his hand raised. So, please.

MR. FRIESEN: Thank you, Mr. Lucas.

You made a brief comment, Dr. Orans, in respect to the roadmap. One piece of your earlier submission that I particularly enjoyed were your comments on the roadmap, and I think I would like to draw the Commission to those comments about how a properly implemented and executed DERs roadmap can be very, very useful in determining pace and prioritization for investment.

I think dynamic pricing has many interesting implications, but at the same time, it requires a tremendous amount of technology, and we can't separate

64

those. I'm an engineer, so I get kind of pragmatic about things like that, and we have a -- we don't even have visibility on many distribution feeders today, let alone the mechanisms to facilitate dynamic pricing, locationally dynamic pricing.

So we have to look at these interim steps, and I think the DERs roadmap provides a very useful tool for determining what these incremental technology steps are, and that opens up a real view into the rate structures that are available and appropriate for each step of that technology implementation.

So I like the DERs roadmap approach, I like how it can be used to establish pace, to establish prioritization, to manage investment, and risk, most importantly to manage risk for ratepayers.

MR. LUCAS: Over to you, Mr. DesLauriers.

MR. DESLAURIERS: Thank you.

I just wanted to follow up on Mr. Lucas's question, I believe, on pricing of energy losses and rates and how that might differ.

And I'm not an electrical engineer, but my understanding is that losses really are a function of voltage and distance, and it's very difficult to assign a location-specific loss factor the way the loss studies are done and computed, and so with regards to

65

how we handle losses in our cost-of-service studies, they're generally assigned across all of the service classes on a primary and secondary distribution voltage basis.

But getting it down to a basis lower than that, true rates, is very difficult, and we haven't necessarily seen it, and I don't think at all, we do assign loss factors for primary and secondary, but down to specific rate classes down to the cul-de-sac, I don't believe is practical at this time.

MR. LUCAS: Thanks. Those are helpful comments.

And with respect to the roadmap, we do have a set of questions that we will pursue on that topic after lunch, but I agree with you, Mr. Friesen.

Now I would like to shift to thinking about non-wires alternatives as well.

And so you four have just said now, as well as in your written IR responses, don't focus on dynamic pricing, we should instead start focusing on developing a cost-effective procurement process for non-wires alternatives.

So if we think about -- if we stay with this idea of dynamic pricing, not just -- like, if we lose the idea of dynamic pricing and the geographical element of

66

it, and we just think about dynamic pricing in the form of reflecting Alberta's wholesale pool price of energy, and maybe we include distribution line losses or maybe we don't, depending on the complexity, would you recommend -- would your recommendation change? Would you still recommend leaving that idea to the side and focusing on designing an effective procurement process for NWAs?

And this question is open to anybody who would like to respond. Everyone is being so shy now.

Mr. DesLauriers.

MR. DESLAURIERS: Well, I'll kick the conversation off. I think you can read from our report and our IR responses that we are very supportive of non-wires alternatives and any kind of approach or mechanism to introduce that into distribution system planning.

Underlying that, though, we believe that having rates that send proper price signals and that are reflective of costs on the system will establish the proper context in which to evaluate the cost effectiveness of non-wire alternatives against more traditional processes.

And so we believe that, although we're supportive of that, we would encourage that, to the extent that there are iterations or refinements to rates that can

67

provide proper cost signals, that that would be something we would recommend in tandem with the a non-wires alternatives.

MR. LUCAS: Thank you.

Anybody else who would like to comment on that?

Well, Dr. Orans, I'll, I guess, go one step further.

So you recommended pursuing an efficient procurement process for developing non-wires alternatives.

Can you help me understand what that might look like in the Alberta context, and how would you recommend objectively determining the value of non-wires alternatives?

DR. ORANS: Rather than dive into all the details about that calculation, because it can get very complex really quickly, I would say that I would like to see the Commission form a group -- you know, a stakeholder group, a distribution owners group, et cetera, that could define collectively what they mean by distribution alternative, term, duration, what qualifies, et cetera. And it not just be a simple, is this dispatchable, is it not dispatchable. It would be a detailed estimate of what each whole set of alternatives, whether they are micro-grids, whether

68

they are DERs, whether they're demand response, whether it's energy efficiency, could provide, and make it a generic methodology that could be applied in any sets of areas.

If you -- I don't remember who brought it up -- I think Dr. Faruqui brought up New York.

So we did -- we have done a lot of work in New York on non-wires alternatives. If you look at our -- we did the roadmap, which has 1800 megawatts of battery storage in New York. Most of that is going into downtown New York City, into Con Ed service territory, and if you look at the calls that Con Ed had for storage, they basically gave -- you know, they didn't give 20-year contracts for storage, they gave 7-year contracts, leaving the remainder of the value to the distribution proposer and owner. They would contract fixed price for seven years and let the owner have the residual value to energy, might get recontracted or not.

There are whole sets of issues that needed to be defined in getting a reasonable contracting and procurement mechanism that accurately defines avoided cost and value to all customers, provides an opportunity for people to reasonably construct alternatives that would lower costs on the distribution

69

system.

It's detailed. There's a lot of work in other areas that you can borrow from. The Commission should form a group to start that process, I would recommend, as soon as possible.

MR. LUCAS: Fair. So maybe we'll switch back to you, Mr. Friesen.

So you mentioned, from an engineering standpoint, we don't have visibility on our current non-wires -- pardon me -- on our current distribution systems, so when we think about non-wires alternatives, I think it's pretty easy to quantify the costs, but can you quantify that benefit in any meaningful way without that visibility?

MR. FRIESEN: Well, I think there's two aspects to that. One is most of our ancillary services today are provided on the distribution system by DFO-owned equipment, and so they've installed whatever visibility they've needed to control those devices, which is often very, very localized, particularly in terms of voltage support and things like that.

If you want to engage third party -- particularly third party behind the metering devices to provide those ancillary services, you need, first and foremost, a way of determining the need, the location, and you

70

need to be able to measure the delivery of the service. That requires visibility in the term -- you know, in respect to smart meters, the back-end systems to do that in near realtime, all of which don't exist in sufficient quantity or state to facilitate that.

So I believe we're -- we're still a ways away from having the infrastructure in place to actively facilitate a DERs market for providing ancillary services, particularly behind the meter equipment.

It might be a little different with larger distribution-connected facilities, where you can put that metering and monitoring infrastructure in place at a more reasonable cost, but we've got a time frame here, and there are many moving pieces within that time frame, and visibility right now would be, in my view, a significant constraint to the near-term implementation of DERs -- third-party DERs provided ancillary services, particularly from behind the meter installations.

I don't know, does that sort of answer your question?

MR. LUCAS: I think so, yes.

I saw Dr. Faruqui raise his hand.

DR. FARUQUI: Yes. I wanted to just make some infrastructure kind of comments, intellectual

71

infrastructure.

My understanding of Alberta is that there is very little activity currently in the province as far as solar rooftop deployments go or battery storage or EVs or energy efficiency or demand response. Now, I could be wrong on that, but I have been a visitor to Alberta over the years, going back to 1993, for conferences, for work with the AUC, for work with ATCO; and, you know, I know a lot of folks there, I keep notes on the penetration of these new technologies, and for all kinds of reasons that you know better than me, penetration is very limited, number one.

Number two, there is no real AMI deployment. So I also heard, at least from my client, that there is no congestion issue currently that they're looking at.

So the notion of non-wires alternatives obviously is an important notion, it's receiving interest throughout the globe. But what might be helpful, and I think Dr. Orans indicated this, is initially to have a stakeholder conversation just to size up the opportunity and then to look at the costs and the benefits.

Unless that's done, a lot of what we are perhaps going to be doing is talking about states that are much, much further along on these issues, and trying to

72

emulate them may not be the best use of time, because Hawaii, California, New York, they are way out there when it comes to deployment of all of these new technologies.

California, in particular. One quarter of the US solar installation are in one state; half of the EVs are in one state, and that's California.

And so why is that the case? Well, prices of electricity are very high. That's why you have so much penetration of solar rooftop. The same thing is true in Hawaii. Hawaii ended net metering, and now they have 60 percent of the new installations of battery storage coming in with the solar installations. Those are issues that are really shaping the grid in those areas today, and not ten years out.

So for Alberta to begin this journey is important, but it's a question of what comes first, and I think the first thing should be a stakeholder conversation, different viewpoints, and, of course, an assessment of the technical and economic potential of these NWAs.

If the potential is very small, for all kinds of reasons that are specific to Alberta, then you may approach it differently; but if there's a lot of urgency, then you have to move much faster, like the congestion in New York City is a very different story

73

from what we have in much of Alberta.

So it's just a question of perspective. I just wanted to share that.

MR. LUCAS: Mr. DesLauriers or Mr. Reese, did you want to step in?

MR. REESE: Mr. DesLauriers had raised his hand.

MR. DESLAURIERS: Thank you. Very quickly.

We support a stakeholder session as well, and I think that this discussion really ties in nicely with all of the viewpoints of the experts today on this topic. I think there is a need for a stakeholder session. I think the success of evaluating non-wire alternatives really goes back to the success and the precision that the group can have in accurately predicting what the avoided costs are and what goes into an avoided cost analysis, and that's part of a cost-benefit analysis of each state, California, New York, Hawaii, has done, and others are anticipating doing, but unless those avoided costs can really be measured accurately, it's very difficult to come up and deliver a consensus decision on what the value of non-wire alternatives are. There are some states that measure some benefits that are very difficult to quantify at this point in time like the value of carbon

74

pricing, and there are others that do not.

So there's a lot of variation in how to evaluate those avoided costs and we just suggest that that session in that regard might be helpful to set up those parameters.

MR. LUCAS: And, sorry, to clarify, Mr. DesLauriers, are you talking about engaging DERs proponents or technology installers? Or customers more broadly and their interest in deploying some of these technologies?

MR. DESLAURIERS: Well, I think it -- the broader the better because I think there are good viewpoints from all of the different stakeholder groups involved, and there are probably -- you know, some groups probably have a particular viewpoint that's valuable in being heard, and there are technical details that might come from experts within particular groups that are valuable.

So I believe a stakeholder group involving regulators and customers, as well as service providers, would be recommended.

MR. LUCAS: So that, I guess, aligns with what Dr. Faruqui was suggesting in engaging customers.

So can we go one step further, and help me get a better picture of what it is you're recommending.

75

So are you talking about engaging the UCA and the CCA as consumer advocacy groups? Or are you talking more, like, kind of a statistical sampling of customers and focus groups sitting down directly with customers? And, if so, who would you suggest lead that? And what kind of conversations or objectives would you have in sitting down with those individual customers?

MR. DESLAURIERS: Well, you know what, I don't know that I would necessarily brought the thought process down to that level of detail.

I think that it would be a stakeholder group represented by representatives of different interests in the question of what non-wires alternatives might deliver and what the value of avoided costs are.

So, you know, open for discussion, but I think it probably would be something that the AUC would want to lead and set up the context for, and that individual customer groups could be represented in the stakeholder process in that way.

I don't necessarily see that focus groups down to the customer level as being the only process would be something that in and of itself would be recommended. I think there's a broader discussion from the utility viewpoint, the customer viewpoint, regulatory viewpoint, and service provider viewpoint.

76

So, you know, open to discussion, but it could be an AUC-led stakeholder workshop where -- very much like the proceeding we're in today where reports and comments are filed and there's an open conversation about what are -- where the agreements are and where maybe some of the different viewpoints may lay.

MR. LUCAS: Dr. Faruqui, do you have anything to add to this idea of how we might implement this customer engagement kind of approach that you recommended?

DR. FARUQUI: So I agree with what was just said, and I think initially it should begin with a higher level stakeholder involvement led by the AUC, just see who is interested in it, who are the parties -- it could be the same parties that have submitted comments in these proceedings.

For example, I saw ChargePoint was one of those entities. I don't know to what extent the solar industry or the battery storage industry even exists today in Alberta. I'm sure there is some sliver of existence. And for Edmonton, has the fourth highest amount of solar radiation on the globe, the first one being Cairo, Egypt. So, of course, most of the time there is cloud cover and snow and rain and sleet.

So it's an infrastructure development at task

77

that will take some time and effort. I think the AUC should lead it. If the parties are invited, I think they should look certainly at avoided costs, they should also look at the value and the benefits created, and then if it's found to be a useful journey, then perhaps the AUC should lead a study to quantify the benefits, and that is where I believe the individual customer focus groups will be relevant. Also conversations with builders, car dealerships, manufacturing companies.

So like a staged approach beginning with, initially, a broad stakeholder conception and then gradually coming down closer to the actual end-user market, because if the end user is not going to buy these DERs, then there is no existence of NWAs. NWAs only have meaning if the customer is interested in becoming a part of the new strategy.

I am optimistic. I mean, just about everywhere else throughout the globe, customers are now equipped with digital technologies, they have smart phones, they have smart computers, they have digital appliances. It's just a question of what are the prices of electricity today and are they sufficiently motivating them, you want to look at non-wires alternatives, or NWAs.

78

MR. REESE: I'll just take note that we're currently at 11:00 where we had a scheduled 20-minute break. I understand that Commissioner van Egteren has suggested that we may consider going through until lunch. Alternatively, we could scale back on the break and have a short bio break for panelists and others, or we could continue with the break as currently scheduled?

I put that in your capable hands, Commissioner Romaniuk.

THE CHAIR: I've just checked here with Commissioner Collins. She's okay to go through. I'm fine to go through.

Are panelists okay to continue on for the next hour? Just raise your hand if you are.

Okay. So if there's no objection, then let's go through till 12 noon. Thank you.

MR. LUCAS: So I want to check in with my colleague, Mr. Bourque. I think he also might have some follow-up questions that he wanted to chime in on.

MR. BOURQUE: Thank you very much, Mr. Lucas.

I wanted to focus the first question to Mr. DesLauriers.

You had mentioned that, over a sufficiently narrow period of time, it's not clear what the difference

79

between a demand charge and a volumetric charge is. I wonder if you would be so kind as to elaborate on that point.

MR. DESLAURIERS: Well, I think that all we're really saying there is that, over a very narrow period of time, let's even make it an extreme example of one hour, a kWh-based charge and a demand-based charge is no different. You're just recovering the cost of that one hour of unit.

I think what we're trying to reinforce in that statement there, Mr. Bourque, is that, you know, as we've really probably discussed at length this morning, most of the costs on a distribution system, within the short term, within a rate-making context if you will, are fixed costs that are embedded and sunk, but that, you know, it's just sort of an example to show that time frame is a very important dimension to consider in all of these issues, whether, you know, you're looking at rate design or you're looking at capacity expansion, or you're looking at non-wires alternatives, there's always a dimension of time that has to be considered.

MR. BOURQUE: Thank you.

And then to pivot to Dr. Faruqui.

You mention that there -- or, actually, a question: Are there any significant differences

80

between the time-of-use demand charge you proposed versus the time-of-use volume charge?

And to start off, could you explain in detail what you had anticipated by a time-of-use demand charge? I believe most participants would be familiar with a time-of-use volumetric charge, but if you could elaborate on what a time-of-use demand charge is and then the differences between time-of-use volumetric and time-of-use demand?

DR. FARUQUI: Sure, happy to do that.

So a time-of-use demand charge, let's suppose, to keep it simple, we have two pricing periods, peak and off peak. Let's assume they're defined with respect to the distribution peak, which may not be the same as the generational transmission peak, just focusing on distribution charges. So let's say the distribution system, just making up an example here, peaks between 7 p.m. and 9 p.m. or maybe 7 p.m. to 10 p.m., it's an evening peak, residential load, and then you have all of the other hours.

So you will have a demand charge for both periods. You will have a demand charge for the peak period and you would have a smaller demand charge for the off-peak period.

So it's as simple as that. It's just a split

81

demand charge with a higher value when the grid is more congested and you're putting a bigger demand on the system, it's more expensive to meet that demand. You time differentiate the demand charges.

The way most people do demand charges, they just have one number, and that one number just applies to the peak period, and during the off peak it is zero, but it is still two. One is the peak period demand charge and then there is the non-existent demand charge, which is basically a demand charge of zero. That's for demand charges that vary with time.

Then you have the non-coincident peak version of demand charges, which are there regardless of time of occurrence.

So I was using that term "time-based" demand charge to distinguish the two categories of demand charges, one being regardless of time, it's your maximum number, that's your NCP demand charge, and it was not very popular with consumers anywhere; and then you have the one that you have some control over and you give it some time variation.

Now, compare that with the time-of-use energy charge as the contrast. So demand is not measured, the customer doesn't have to worry about a spike in their demand, they just have to focus on energy. And so

82

there is an energy peak period price, there's a lower energy off-peak period price, and you can actually combine demand charges with energy charges, as we have been discussing.

And so then you could have the ultimate jigsaw puzzle. There are time periods and you have demand charges and you have energy charges. Believe me, for residential customers, that might be overkill. I mean, I have certainly talked about it, discussed it at conferences. People have a tough time just with a simple demand charge coexisting with an energy charge.

I did some work in the Middle East and one question I got was, you're going to charge us twice for the same thing. I said no, they are two different things. Energy is different from demand. It becomes a longer conversation than you may want to have.

So the simplest case is just focus on the fixed charge plus a demand charge, make the demand charge time varying, then you have addressed most of the issues that we have been discussing here. For distribution only.

Now, I did hear earlier on some good discussion about retailer pricing of energy, and that could be either RTP or time of use. Even in a market like Alberta, I think that would be worth exploring.

83

And the market that comes the closest to your market, at least in my conception, is the market in Texas with Urquhart, and I have done some work there recently and I have discovered that the retailers are now finally discovering the virtues of time-of-use pricing, and they have some one million customers now in Texas, residential customers, on time-of-use energy rates.

So, you know, the future is full of possibilities.

MR. BOURQUE: Thank you very much.

I would like to tie together the two ideas that were just discussed.

As my colleague Mr. Lucas alluded to, we do have some coincident peak pricing in our transmission tariff, and that transmission tariff is redesigned at the distribution tariff level, so those price signals have the potential to get distorted. If the transmission price signal is a CP, how does one go about designing a CP price for residential customers for understandability?

And if small enough time scales demand charges do end up looking like volumetric charges, what is the ideal way in which these signals can be sent through to the customers without doing too much of a signal mismatch?

84

And this question is open to anyone.

DR. FARUQUI: If I can ask a clarifying question, not being very familiar with how the structure of charges is today.

So what does the typical residential customer bill look like? If you can just give me sort of a -- I've seen some of them, but I don't have it in front of me, but is transmission broken off separately from distribution and from generation for the average customer's bill?

MR. BOURQUE: At present, residential bills contain line items with each of those charges broken down, and not necessarily have the price signals for each line item broken down, but, nevertheless, they are separate schedules.

For the DFOs, they vary by DFO service territory, and in the preliminary IRs to the Combined Module, we created a table that had price signals such as distribution rates might be $20 fixed and 1 cent volumetric recovery, and then the transmission schedule might be something like roughly 4 cents per kilowatt hour as a transmission recovery.

And so noting that those price signals at the transmission level come from rates CTS, they're redesigned due to either a meter being a cumulative

85

meter and unable to make time distinctions, or understandability, or for a myriad of other reasons. Some of those price signals may have been taken into consideration -- or changed, taking into consideration relative on right times of use.

So in that regard, though, if one wanted to send the correct price signal that is sent at the transmission level through to customers that then go through a distribution system, how should those price signals be flown through to customers in an understandable way?

Because, as you alluded to, having NCP and CP demand charges for individual customers is a very challenging task.

DR. FARUQUI: So it's absolutely challenging. And the way -- so there are three elements in your question: One is customer understandability, which is absolutely the key to rate design success. I believe we have to be customer centric as we look at rate design changes in the future.

But in addition to that you need the metering capability to be able to actually do the measurements.

And, third, you need to have innovative rate designs. Otherwise, there is no reason for doing any of this.

86

So looking at examples from around the US, like in Maryland and California and elsewhere, even before demand charges enter the picture, I have seen time-of-use charges for energy and transmission and distribution that are not exactly the same number or defined over the same period. The customer is shown the details, for those who have an interest in looking at the details, but, ultimately, it adds up and it tells the customer this is your total bill, so much is for transmission, distribution, and generation, and if you are on a time-of-use rate, you have the right meter, for example, then it's broken up into those buckets.

As I mentioned earlier, I switched over and became a prosumer or prosumager, I now get a 14-page bill, and if you count the cover page, it's 15 pages; and I called the customer service centre of the local utility, and I said, do you really want me to spend an hour trying to understand my bill? Is there a simpler way to show it? And we had some good discussion and debate, and the answer was, just look at the second page and the last page, and throw the others away. So, obviously, there's a lot of improvement that can be made. The consumer psychology has to be factored in, not just the engineering details.

87

So, to summarize, if you have the meters and you have the algorithms for transmission, distribution, and generation, you can show as much as you want to the customer, but nine out of ten customers will simply want to know, what is my total cost and if it varies by time of day or varies by demand, how much is that variation, and what can I do to lower the cost. That's the number one desire of most customers.

I don't know if I answered your question.

MR. BOURQUE: You did. And I see Dr. Orans has just raised his hand. So, please, Dr. Orans.

Your microphone is not turned on, Dr. Orans.

DR. ORANS: I don't want to jump in front of anybody else who wants to answer this, but I agree with Dr. Faruqui that the information -- getting the information to people so that they can do the right thing is critical here, and too much information is not better than the right amount.

But to make it more Alberta specific -- and this is where I think the roadmap -- coming back to the roadmap, this is a critical issue right now. So more people are installing more generators behind the meter at the transmission and the distribution level.

Dr. Faruqui, I don't know if you're aware, but the 12 CP rate in the transmission system is $10 a kilowatt

88

month, on the order of that. That's an astronomically high number on the order of things, and it pays for a customer to install a CT to bypass a bulk system that is largely built and largely has no variable cost in the short-run going forward.

That permeates through into the distribution system because distribution has to pay credits back to transmission when they lose money. If people do the same thing at the distribution level, whether that is battery storage or whether it is rooftop PV or any forms of DER.

So I think another reason to have this avoided cost methodology at the transmission and distribution group, stakeholder group approved methodology, is to be able to apply it at the transmission and the distribution levels. So then you can make a decision, Dr. Faruqui, on the tradeoff between, here's the real information, let's get that first, and then let's talk about what is an efficient level that's the right amount for information and response at all the levels.

But the critical issue right now -- and this is where -- you know -- and I have certainly been guilty of using this word "uneconomic bypass" as much as anybody; and the only reason I'm using it, it's not pejorative, is it is cost shifting and it is happening,

89

a large extent now, in the transmission system, I'm convinced I've looked hard enough at that problem, I'm not sure it's happening as much at the distribution system level, but if Alberta doesn't get it right on the transmission system level, there is a real chance this same thing happens at the distribution level.

And, Dr. Faruqui, you and I watched very closely this happened in Hawaii, and it happened very quickly. We designed with them a (phonetic) tariff and all its structure. So we were as guilty as anybody in letting that happen, and I wouldn't want to see that happen in Alberta because I don't think it's the right roadmap pathway to pursue.

MR. BOURQUE: Mr. DesLauriers?

MR. DESLAURIERS: Just very quickly. I agree with everything that's been said here today.

I just want to reinforce the two points that seem to be part of a thread throughout this conversation. It's really price signal and cost shifting when it comes to the transmission system, and I'm certainly not as familiar with the Alberta system as Dr. Orans is or Dr. Faruqui; but, you know, we did make a point in our report that, you know, if we assume that the 12 CP cost allocation approach and the 12 CP demand charge is the most suitable for transmission and that's how

90

transmission systems are built and to accommodate that peak.

In terms of price signals, if we're just simply giving price signals for large, sophisticated customers who have energy managers or have the metering to do so to avoid that 12 CP and we're merely just shifting the peak to another time and shifting costs from customers, I'm not sure there's a real economic value that's gained from that. So I just want to, you know, point you to that piece in our report and remind others of that.

With regards to the price of a transmission unbundled rate, I'm a ratepayer up in Massachusetts, and similar to Alberta, I see a transmission component to my bill, but it's billed through on an energy-charge basis or a variable-charge basis. So, really, there is no price signal per se that's communicated to me as a consumer in Massachusetts that allows me to do anything about avoiding the transmission peak as a residential customer.

And I don't -- back to Dr. Faruqui's point -- I don't believe that the complexity that's introduced by a CP-based demand charge for residential customers is really of value given the use of understanding and the trouble with consumer understandability of that tariff.

91

So I haven't seen a lot of CP-based residential charges for transmission, and I believe that's probably the reason why.

MR. BOURQUE: So I have two more questions before I turn to a colleague.

My first question is related to the wires of both transmission and distribution, and that is that, if I understand this correctly, the transmission and distribution systems are -- have an installed capacity to them, and that demand charges are a proxy to try to incent customers to use that demand efficiently. Is my understanding there correct?

Dr. Faruqui.

DR. FARUQUI: I believe your understanding is correct.

MR. BOURQUE: So a follow-up to one of Mr. Friesen's comments that there is not currently a lot of visibility of either what that installed capacity is or what those flows are.

If the year were 2040, and one could envision that information is abundant, both about what has been installed, as well as flows, regardless of who may have access to that information, with all of that information at your disposal, would a recommendation of some sort of dynamic pricing change, given all of that

92

information, given the sophistication that may come about in the future?

Please, Mr. Friesen.

MR. FRIESEN: So I would be hesitant to characterize the statement I made earlier about visibility inferring that DFOs are not aware of the capacity of their current system. I think DFOs have a pretty astute understanding of the capacity of their existing system.

And those capacity ratings were established, or the equipment to provide those capacity ratings was established, based on studies that the DFO undertook as part of their planning process, which you could argue would have been hampered to some degree by a lack of more detailed information at the feeder level. So they're using an aggregated or an average number, probably multiplied by the number of customers on a feeder, to come up with some type of planning criteria.

So that information is used, and has been used for decades, to design the distribution system, but when you talk about that 2040 scenario, we have a lot more information, and hopefully that information will be available in near realtime.

We're now talking about control. And the visibility that I was referring to that is lacking is

93

the visibility in respect to realtime control, and the integration of DERs in realtime to manage the distribution system, which is a little bit different than what your statement appeared to infer or your question appeared to infer.

So I think that we have an opportunity to implement multipart rates, as been described throughout this conversation, in simplified forms, potentially using static time periods, and that, as customers become familiar and comfortable with those price signals, they are in essence -- or we are in essence preparing them for a dynamic environment.

So I don't think there should be an assumption made that a dynamic pricing structure is required to achieve economic efficiency. I think we have an opportunity, though, to look at how more simpler rate tariff structures that we can implement with the technology that's available today influence the economic efficiency while providing customers with some forward-looking price signals. We desperately need customers to have forward-looking price signals, and we can't ignore that in the conversation around fixed costs.

Yes, embedded costs exist. We can't argue with that aspect, but without forward-looking price signals

94

we have no hope of changing the future, and we need to look at what changes a consumer behaviour will do to the future design of the distribution system.

And we can achieve that with some of the rate structures, a simpler static rate, time-varying rate structures, that we've talked about today. We don't need to make an immediate leap to dynamic and we don't have to see dynamic pricing as a mandatory end game.

I think we have a path that we can walk down, and we can determine when we walk down that path to a sufficient degree to reflect cost causation and appropriate allocation of costs between rate classes and customers.

MR. BOURQUE: Dr. Orans.

DR. ORANS: I would agree with all of those comments.

I guess there's one little additional piece I would like to add on. If you look up Dr. Bob Wilson and Dr. Hung-po Chao -- Dr. Wilson was a professor at the business school of Stanford, and Hung-po Chao was doing some very seminal work on the value of interruptible, curtailable rates at Epbury for a large number of years. And they collaborated on some really interesting work showing, in telecom, you get most of efficiency from really simple forms of quantity-based

95

rationing.

So they have experiments that show, for example, the grid and telecom used to be constrained at Thanksgiving and Christmas. Everybody was calling home. If you just select two options: I need to make this call or I could make this call at another time.

Even without a known price beforehand, they showed you get a large -- you get effective quantity curtailment and rationing of scarce capacity just on a two-part simple design like that during one constrained period.

You know, it's a lot like -- Dr. Faruqui, it's a lot like CPP in that way; right? It has something really simple, most of the time, it's really easy, and customers don't need to calculate anything; they just need to say whether they need to or not.

And so I agree with Mr. Friesen, you know, utilities need more information to be able to do that, they can't just do it now, but I also agree, we don't need to get to an end state of realtime dynamic pricing, and you're going to be way along the road before you need to make that decision, and there are a whole number and slew of other programs you can implement before that.

MR. BOURQUE: Dr. Faruqui, please.

96

DR. FARUQUI: I just wanted to add a couple of points. I think I agree with just about everything that I've heard.

The year 2040 was mentioned, and I thought I would let you know that I actually wrote a paper one time called "A Pricing Odyssey" and it was the year 2040. It was like a dream. Somebody wakes up -- they fell asleep like Rip Van Winkle and they wake up and the world is totally changed (phonetic), the world of electricity specifically. There are prices to devices, there's automation, and life is really easy. They have lower bills, the grid is less expensive, it's all renewable, it's very intermittent, and you have growth (phonetic) flexibility just automatically built in.

Now, I was not thinking primarily of the distribution grid, I was thinking of the entire operation that we are talking about. But there is a lot of movement underway, and mostly in California, in trying to make that vision real, getting prices to devices.

Fred Schweppe, as some of you might remember, the MIT professor, wrote a seminal paper on that called, "Homeostatic Control." It was an electrical engineering kind of terminology, but basically it was getting prices to devices.

97

I think between now, which is 2020 and 2040, so much would change that we can't even conceptually begin to list what would change. So what seems cumbersome and painful today from a consumer perspective will become seamless and easy, but that's two decades away.

The question is how do we get there. I think that's where the roadmap comes in.

But while we are discussing the roadmap and innovation, I thought I'd mention briefly something that is generating a lot of interest in rate design conversations, actually, throughout the globe, and it's not dynamic pricing, it's not demand charges, it's not anything we have been discussing like multipart tariffs, it is the complete opposite, and you might think it's a throwback to the dark ages, but it's out there and it's being dressed up to look as modern as one can possibly imagine something being. It's called the "fixed bill." Okay?

So the "fixed bill" is Netflix pricing reborn, and everybody is looking at telecom and they're looking at cable, they're saying people want simplicity. Who the hell cares what time of day it is, mostly a capacity issue, and over the long haul energy will be virtually zero price, or so goes the theory. So many utilities today are offering fixed bill products, not just for

98

distribution but for the entire bill.

Many people who are active in the prosumer community already are on a fixed bill. The leasing program that you have from a solar supplier, that is a fixed bill, and it's lower than your current bill, that's how they get you; right? I mean, it sort of locks you into a bill that is 10 or 20 percent lower than your current bill. It's already there.

And what I wanted to just mention briefly is, I know dynamic pricing is hot and attractive, and I have certainly supported it and continue to support it, but the reality is relatively few residential customers have shown any interest for that product.

You have about 50,000 customers in the entire United States with roughly 130 million residential customers, 50,000 on realtime pricing in the land of Lincoln, the state of Illinois, the two utilities there, one 30,000, one 20,000.

So it has opportunities, but until it becomes simpler to implement and automated, maybe it will by 2040, I don't think it's a realistic goal, particularly in Alberta, with very limited metering capability, with very limited history and time variation -- and the number one objection I get when the topic comes up is that the distribution and transmission charges are

99

40 percent of the bill, there's not that much that can be made into realtime.

I mean, those are issues in a stakeholder conversation that I think need to be voiced and heard.

I did three staples of workshops last year in the province of New Brunswick on rate design reform. And they are not structured the same way that Alberta is, vertically integrated, the market (phonetic), as you know, but, ultimately, it is the same consumer issues, it's prosumers. I saw, actually, much to my surprise, three or four model 3 Teslas out there too. So the question was how to change rates and the consensus was, do not change them. Just leave it the way it is.

And one of the staff members of the Board said to me, the Board has the option of not making any changes at all. I said, certainly, I'm just a facilitator here. I'm not pushing for reform. You can certainly stay in the 19th century if you wish, you know, who is going to stop you.

The reality is the consumers have already gone into the 21st century and you can't stay constant. You have to get ahead of change. You have to anticipate innovation and you have to try to leverage that to do it in a way that doesn't create cross-subsidies and, yes, uneconomic bypass I believe is still a term that

100

some of us use. I think that's -- now, you could say there is no such thing, every bypass is economic and let's have a debate on that issue, then, as to what is economic and what is uneconomic. That itself is an empirical question.

The solar industry will argue there is no such thing as uneconomic bypass. I'm sure you've seen the report that SCE put out saying that it will cost them $2 billion to create the two-way grid to incorporate renewable energy resources. They are immediately criticized for saying, hey, this is going to lower costs, this is going to raise costs? Are we on the same planet? Are we in the same state?

So your stakeholders will have similarly vigorous debates.

MR. REESE: Thank you, Dr. Faruqui, for those additional comments.

Geoff, do you have further questions?

MR. BOURQUE: No, I just wanted to follow up before I pass to my colleague, Mr. Fuchshuber.

I didn't mean to allege, Mr. Friesen, that the DFOs did not have information or the TFOs did not have information about the capacity. Just rather that that capacity is there, one party knows it, and another party is trying to be incented to use it correctly

101

using demand charges.

To that end, I would like to pass it off to my colleague, Mr. Fuchshuber.

MR. FUCHSHUBER: Good morning, panel. I'm just trying to start my video here.

All right. While we wait to get that started, I would like to change the direction from tariffs for a moment and talk a little bit about, exploring the interaction of what I understand might be potentially substantial volumes of distribution-connected non-wires alternatives with Alberta's wholesale energy market.

And I note your recommendations earlier, that, to engage in some consultation and to assess the scope of non-wires alternatives and really tailor an Alberta-specific solution. So, with that in mind, some of these questions might seem a little premature, but we have you here today, and to the extent you're comfortable providing some initial thoughts, we would appreciate them.

So to provide context for these questions, I'll first outline some aspects to our markets, which you may find relevant. I imagine you're aware of certain circumstances.

So the Alberta Energy market is an energy-only market. It's a realtime market. There's no formal

102

time-ahead market. It clears with a single province-wide price. The system has -- I think it has been mentioned already -- it is planned to be free of congestion under normal circumstances, and the planned use of transmission must-run, which is a non-wires alternative at the transmission level is constrained.

And, nevertheless, if transmission must-run is used operationally, which as I say, it's not planned to be, the ISO takes action to restore the pool price to the level it would have been had the TMR not occurred. So, in other words, the use of transmission must-run is considered as distorting the pool price. And because of the way the system is planned, that currently happens very rarely.

So with all of that in mind, I had a few questions.

The first one is if, for simplicity, I was to consider, so the core non-wires alternative tradeoff as being between relying on all energy being provided by upstream generators in the pool along with sufficient wires to deliver that energy versus obtaining some of the energy from downstream, DERs I suppose, coupled with less expensive wires, that's the core tradeoff we're looking at here, would it be fair to expect, then, that the economics between those scenarios depend

103

not only on the difference in the wires cost, but also the forecast difference in the cost of energy from the pool and from the downstream DERs?

And then my follow-up to that is, if that's the case, how should that variation in energy prices be accounted for?

Go ahead, Dr. Orans.

DR. ORANS: I would invite my colleagues to also jump in here, but I think you've set this up really nicely for AWS.

Basically, the methodology we talked about an hour ago would define an appropriate benchmark cost if it's non-constrained, you know, pool-based power with otherwise applicable, what the distribution and transmission providers would -- it would cost to deliver that power. There's your benchmark cost to beat for your AWS bid; right?

It's got a characteristic, it's got a location, it's got a shape, and it's got a duration, and you're asking for a contractual, relatively long-term -- let's say it was like Con Ed's seven-year storage call -- bid that would match in all those characteristics that benchmark.

MR. FUCHSHUBER: Go ahead, Mr. DesLauriers.

MR. DESLAURIERS: I agree with that.

104

I also just want to -- just thinking about the question in terms of what the parameters might be for evaluation of the cost tradeoff.

One topic I didn't hear about, which I think is important to also consider in the tradeoff, is the value of reliability, which really would be one metric that should be considered if you're looking at a premise where you're evaluating a traditional generator upstream source, dispatchable, let's assume, versus an alternative of downstream DERs and related wires.

You know, I think, from my point of view, there's probably not a lot of difference in terms of the value on the system, but one question that might arise is, is there any degradation of reliability or are there any incremental costs that need to be considered moving into the model of the downstream DERs.

So I just add that into the consideration and maybe ask others to comment if they wished.

MR. FRIESEN: Sorry, this is Dale.

MR. FUCHSHUBER: Go ahead, Mr. Friesen.

MR. FRIESEN: Thank you. You know, I think there's an interesting question within the context of your question that relates to the ancillary services that are provided to the transmission system and those that are provided to the distribution system, and the

105

criteria for those ancillary services and how they vary between the two systems due to the fact that the transmission system is a very interconnected system, while the distribution system is more radial in nature.

So, at the distribution level, you're talking about those ancillary services very much at the feeder level, so they're very locational, and they relate to those reliability criteria that Mr. DesLauriers spoke to, and the impact that both load and supply may have on the reliability of that distribution feeder.

Which is a little bit of a different discussion than the energy market, and I think we have to be very careful when we talk about NWA that we separate those two. The functions of reliability and the functions of energy supply, while interrelated, still are dealt with in a different way, and we have to make sure that the playing field for the provision of energy is consistent.

So we can't impose costs on distribution generators, connected generators, if we're not willing to impose costs on transmission-connected generators. So there has to be some level playing field if they're providing energy to the same pool.

And given the market size in Alberta, I don't really see a strong driver for creating regional power

106

pools or distribution centric power pools. I believe that's a level of complexity that a market the size of Alberta doesn't necessarily need, but there may be a future where we allow parties to sell energy to each other, and is that something that Alberta has considered, where I, as a residential owner with DERs, may want to sell power to my neighbour, a third-party transaction without engaging the pool per se in the way it is designed today.

So I think there are aspects to this whole non-wire services discussion that we have to be very careful that we are speaking about the same thing. If we're speaking about energy, let's be clear, and if we're speaking about reliability, let's be clear that we don't create conflict between those two discussions.

Thank you.

MR. FUCHSHUBER: Thank you.

Dr. Orans, I see you put your hand up there.

DR. ORANS: Can everybody hear me?

I agree, this issue on reliability is critical, and I agree with Mr. Friesen, this issue of who is in control of the non-wires service and what benefits you get is really important.

A number of you might ask, well, why did we have all those funny-looking diagrams in our testimony.

107

So that came out of -- we weren't locked -- I know there's one person listening to this call who knows this because he was running a company that was part of this whole thing.

So after New York published its massive tome on REV, we were locked on a long hot summer with the utilities in New York trying to figure out what REV really meant, and what REV really meant for DERs, in particular -- and this issue of reliability and/or who was in control was foremost in the issues.

And there's two real worlds under which -- that will come about when Alberta starts to approach the -- what are the avoided costs for DERs and who controls them, and one is a kind of what I'll call DSO-centric model where the non-wires alternative is driven by a DSO need, or a trigger -- Dr. Faruqui, it is the Tesla example you gave in the cul-de-sac -- and there's a problem, and they need to figure out a way to solve it, and with that case, they're in control, they define the parameters, they maintain reliability and get first call on everything: Energy, capacity, any ancillary services that they need and defining what the needs are.

Alternatively, you can have a TSO-driven need, where it's just a call for DERs in general that would

108

stack in with all the other TSO needs, and then any residual capacity left over after that TSO uses up the capacity they need, would qualify for the DSO.

And I think Alberta needs to think carefully about, is the next step in its triggered evolution so that the non-wires alternatives are triggered and controlled and contracted for by DSOs with a residual value going to the bulk season, or is it the other way around.

And I don't want to answer it here, I just think that's a key next step in the roadmap for Alberta to decide.

MR. FUCHSHUBER: Thank you. You have raised a number of points here I would like to pursue a little bit further.

The first one you raised, Dr. Orans, was the benchmark price. And to understand that a little bit more, the use -- is the benchmark price you're thinking the -- a going-forward price during the contract term which is matched to the delivered price of energy on the distribution system? How would it relate to the unknown forward wholesale price?

DR. ORANS: I think in the ideal world, it's got both in there. So you've got an avoided cost of energy delivered through -- let's just assume these

DERs are interconnected at the distribution system, and it's delivered to, let's just say a distribution planning area. It's got the energy costs, it's got relevant transmission costs to the extent there are any, and it's got also the distribution-avoided costs as well, and it's got that total cost of delivered energy to that distribution planning area over a time period and over a size increment.

So let's just do an example. It's ten years and it's 10 megawatts of peak load capacity under some kind of shape. That's the baseline forecast, here are the cost estimates. Can those costs be replaced or mitigated with a DER or some combination of DER alternative?

MR. FUCHSHUBER: Okay. I think I understand what you're saying, then, is that, if it's the DFO perhaps who is contracting for this capacity, they would establish the avoided costs based on their assessments of what they thought the alternative was to procure it from the market, and include in that the value of the voided transmission -- no, the voided wires that they are going to have to otherwise spend, and put that price out there and contract and seek payments -- I guess use that as the basis for the contract and then get offers to provide energy at that price, what the

cost of providing energy at that price would be.

Is that what you're thinking?

DR. ORANS: Yes.

MR. FUCHSHUBER: Okay. All right.

One of the comments that was raised was around the necessity of maintaining a level playing field for energy, I think, and in the context of the Alberta market, which as was said, an energy-only market, where there really aren't capacity contracts or contracts offered to generators for entering the market, at least not by regulated entities, how would you see that playing into the idea of offering contracts to provide non-wire alternative services?

DR. ORANS: I think you do have a very short-term capacity ancillary service market in the generation system, if I'm not mistaken.

So let's just say you had a battery provider who -- and let's say that the DSO needed four hours of capacity, and the battery provider who bid on this provided six. So the first -- and let's say it was DFO triggered and the DFO was going to sign the contract. The DFO would soak up the first four hours, two hours would remain as an extra source of value that the TSO could use and credit, if that's what the contract were signed for, for the six-hour battery, for example.

MR. FUCHSHUBER: Okay. And, sorry, just to clarify, I was thinking more along the perhaps seven- or ten-year contract term that you're considering.

DR. ORANS: Yeah. Exactly the same thing. So you could have this battery installed, it would be a contract for basically services, and the battery would perform on-call based on, you know, signals from the DSO.

The TSO -- if they were going to participate in a TSO program as well, they would need telemetry and controls that the TSO could control for any residual capacity that was left over during that whole time period you're thinking about.

MR. FUCHSHUBER: All right. Thank you.

MR. FRIESEN: Can I just make a quick comment? Going back to the discussion on avoided costs, I think Dr. Orans made one particular comment that was very, very important when he talked about the methodology for determining avoided costs.

He spoke about ten years, 10 megawatts, and then made a comment at shape. That shape is tremendously important to that determination of avoided costs, and I use electric vehicles as an example.

The energy delivery to a battery in an electric vehicles can tremendously change the shape and

resulting cost imposed on the distribution system. If you're looking at a public-charging scenario, with very high charge rates, that will be a different picture for the distribution system than an off-peak residential behind-the-meter charging scenario at a much, much lower charging rate.

So when we define those shapes for determination of -- you know, that benchmark price or that avoided cost, we're going to have to be very careful that we understand how the consumer is using DERs -- or how the consumers are using DERs, because it will lead to very different outcomes for that avoided cost number.

And so we have to -- this is where stakeholder consultation and understanding of market behaviour becomes incredibly important, because broad assumptions may lead to very broad, incorrect answers if we're not careful.

MR. FUCHSHUBER: Thank you.

Go ahead, Dr. Faruqui.

DR. FARUQUI: Just to comment on the EV charging issue that just came up.

As I mentioned, I have an EV and I can charge at home. The off-peak rate is 17 cents. I can go to a supercharger and charge it there for about 25 cents, and it's a lot faster, the supercharger than to charge

at home.

So we also have to think of it from the consumer standpoint as well. A price differential of 8 cents, or whatever, is not going to necessarily change the behaviour and encourage them to charge at home.

And I guess the other comment I wanted to make was something that came up earlier, and Mr. Friesen mentioned it, was the notion of transactive energy or customers trading load shapes; one has a surplus, one has a deficit.

I think that idea is finally getting some traction. Southern California Edison has just completed a pilot, a $3 million study, and the report came out two days ago by Ed Cazalet and his colleagues. And it shows the opportunity is there, but it's still very much like a dream, way out in the future, because the amount of time that people don't have to invest in saving possibly $5 a month on their bill.

But all of these futuristic scenarios are worth mapping out, it's just a question of priorities as to what comes first. I mean, there are hardly any electric vehicles today in Alberta. There are hardly any solar rooftops in Alberta. So it's a question of should we look at 2010 -- I'm sorry, 2020 or 2030 or 2040, and the analysis and the conclusions would be

very different.

MR. FUCHSHUBER: Thank you. And just to follow up with that point, I note that you're saying this is a longer term potential, but to go back to the idea for a moment.

Mr. Friesen, were you suggesting that there should be sort of point-to-point wheeling rates? Is that what you're thinking? Where one customer can supply power to another?

MR. FRIESEN: It would generally be the concept of transactive trading between consumers, yes.

MR. FUCHSHUBER: Okay. In terms of how those participants would participate in the energy market, are you thinking -- I guess where I'm heading towards is much larger transactions perhaps, people offering down schedules and those kinds of things, but perhaps you're thinking this is much smaller and wouldn't need -- I guess what I'm wondering about is, do you see a change in how the energy market operates compared to the current pool-based design that we have?

MR. FRIESEN: It would definitely require some reconsideration of some of the principles in the current market, there's no question about that.

MR. FUCHSHUBER: All right. Thank you.

MR. REESE: It appears that we have -- oh,

he's back. Hi, Dr. Faruqui.

We are approaching our lunch break, and I'm not sure if this is a good spot for us to take the break and pick up after lunch.

DR. FARUQUI: Sorry, I am back. I was expecting that AT&T would do its number on me at some point, and it did, but okay. So, sorry, I think I was almost done. I just wanted to let you know I'm back.

THE CHAIR: Okay. We've had the benefit of only a 10-minute break in the morning, and I'm thinking now more of our court reporter. She probably will benefit from taking our break now.

Let's reconvene at 1:00 Alberta time.

And then we'll make a call, as we did this morning, on whether we have two breaks or one longer break in the afternoon.

But that will come later, so for now, let's terminate our session and come back in just over one hour, 1:00 Alberta time. Thank you.

(PROCEEDINGS ADJOURNED AT 11:58 A.M.)

PROCEEDINGS ADJOURNED TO 1:00 P.M.

Volume 1

June 24, 2020

P.M. Session

(PROCEEDINGS RESUMED AT 1:00 P.M.)

THE CHAIR: I am welcoming everyone back to our afternoon session by virtual meeting. We will have one break this afternoon, roughly at 2:30 Alberta time for 20 minutes.

And with that, I will turn it back to Mr. Reese.

MR. REESE: Thank you, Commissioner Romaniuk. Good afternoon, everyone.

I would just like to take a moment to remind our attendees on the use of the "raised hand" function in the context of this meeting. We'll use the function coming into play if a Commission Panel member or staff directs a question to a party representative other than the four consultants seen on screen.

By raising your hand once a question is directed to you, this will alert our meeting coordinator that a representative is available and ready to answer the question that has been posed to them, and then our meeting coordinator can change the status of that individual to a participant so that they can be seen and heard.

117

As we have communicated in Exhibit 649, following the virtual meeting, all parties will have an opportunity to provide concluding remarks. These may include responses to questions posed for parties by the Commission during the virtual meeting. So there will be an opportunity.

I will now turn it over to Mr. Ayri to begin the session on --

MR. AYRI: Thank you, Mr. Reese.

Good afternoon. My name is Abhinav Ayri, and I will be asking questions on advanced metering infrastructure or AMI.

So to give you a quick overview of what I'll be asking, it will be focused on deployment of the AMI systems, the back-end data processing infrastructure, and deployment through regulatory intervention or the market-based approach.

Before we start the questions, I would like to make a clarification based on some of the IR responses and primarily based on EPCOR's response to the Commission's first IR on AMI.

In that IR, the Commission drew a distinction between the installation of the AMI system and the deployment of back-end data processing infrastructure.

EPCOR pointed out in its response that the AMI

118

meter is only one small component of a functional AMI system, and one needs a basic back-end infrastructure. This includes: The data collection and communication systems, the head-end systems, the meter data management systems, data storage systems, and customer billing systems that are required to make the AMI system, which includes the AMI meter, functional.

This is a good clarification, and this what we will refer to when we say a "basic AMI system" or just an "AMI system."

So, for example, in the case of EPCOR's residential customers, such a basic set-up involves the AMI meters and related infrastructure to enable cumulative energy reads on a monthly basis.

The Commission, in that preamble to the IRs, defined "back-end data processing infrastructure" as the communication network, head-end systems, meter data management systems, and customer information systems which would allow the meter data manager to collect data from the AMI meters at an hourly or more frequent basis for billing.

Customers would have access to their billing data information at the same intervals. However, the system would not need to provide control signals to this customer. And EPCOR pointed this out, that this goes

119

beyond the basic set-up, and this is a fair point. So we are going to refer to such infrastructure as the "enhanced back-end data processing infrastructure."

All right, with all of those words, I'm going to turn over to the questions.

So, Dr. Orans, in your written submission and IR responses, you stated that the deployment of the AMI system was not an all-or-nothing approach and, in fact, is often most effectively done through partial or phased deployment.

But, on the other hand, Dr. Faruqui stated that the AMI system should be deployed universally if it was shown to be cost effective. In order for the benefits to be fully realized, universal widespread deployment is necessary.

So can you gentlemen help me understand if this is a difference of opinion or is this just saying the same thing in different terms?

So, Dr. Orans, you stated that an AMI system should be implemented in a step-by-step process, which seems counter to Dr. Faruqui's statement about widespread deployment. Could you respond to that?

DR. ORANS: Certainly. And I think we're in agreement. I think he also says, this is assuming it's cost effective.

120

So I would say if it's cost effective on a whole system basis, it should be implemented on a whole system basis. If it's more cost effective on a deferred basis, it should be on deferred. It will vary by class and by location and by distribution service provider.

I think we're in pretty much agreement, and I looked at that closely too to see if there was a gap there.

MR. AYRI: Mr. Friesen, did you have anything else to add? Or Mr. DesLauriers?

MR. FRIESEN: No, I think the comment that was just made by Dr. Orans, and the one that was provided in the response by Dr. Faruqui correlated with comments that I made in my -- our response as well.

MR. DESLAURIERS: And this is David DesLauriers. I agree with all of those comments. I do think that in order to fully realize the benefits of AMI, it most likely will be benefits that are near after fully deployed.

We do a lot of work with AMI on the rate and regulatory side in terms of looking at cost recovery for it, and from my experience, I can say that a lot of what you identify for data collection, billing, MDM, the mesh node network, CGRs, the backbone of the

121

system, that's a fairly large component of the overall project cost of an AMI. So, in fact, a lot of that has to be set up before your first deployed AMI meter even pings.

So if we step back and look at the economics of these AMI systems, what we realize is that there's a significant upfront cost in getting this backbone system in, and to the extent that you can add more and more meters to deliver those benefits, I think the cost benefit begins to make more sense. I think it's more difficult if you were to install all of that and only deploy meters for a select few. For instance, those that were willing to burden the cost of that -- share in the cost of that.

MR. AYRI: Thank you.

So, Dr. Faruqui, you said in your responses that if the deployment of the AMI systems were left up to the market forces, where customers have the ability to opt in and pay for the installation of an AMI meter, it would be likely unsuccessful. Could I just get you to expand upon this statement?

DR. FARUQUI: Certainly. I was thinking specifically of a few markets where that approach has been tried out, in particular, in Great Britain and in Germany and parts of Australia. It has not succeeded

122

because, to the customers, it's not clear what's in it for them, so why should they pay extra for a meter that may or may not do anything for them.

In markets where it has been found to be cost effective in terms of whole full-scale deployment by utilities and commissions examining the issue with stakeholders, so you have California as an example, you have Illinois, you have Maryland, and you have many other states in the United States with AMI, approaching a hundred million by year end, most of those deployments have been sort of carried out under the regulatory guidance, and they have been full-scale deployments to make sure that the benefits of distribution automation are fully realized.

If you have selective deployment -- first of all, it's very hard to have selective deployment because customers show very little interest and retailers also show relatively little interest.

Like, take the case of Texas with Urquhart. Urquhart is -- there is no default supply option, as you know. There is just retail supply and there is TDSPs, or transmission distribution service providers. This question was examined there, and a decision was reached by the PUC, to have universal deployment and customers pay for it regardless of what rate structure

123

they're on, regardless of what retailer they're getting their services from, it's a successful model.

As I mentioned in the morning, there are now a million customers voluntarily taking time-varying rates for their energy portion of the bill. They have AMI, if they didn't have AMI, they would not be able to do it, they would have to pay extra, and most of them probably would decline. That's primarily what I meant to say.

But let me add, just as a footnote, that there have been cases with traditional time-of-use rates going back decades where customers have voluntarily signed on to a time-of-use rate and paid something like $4 a month. I was one of those customers in Northern California where the utility offered a rate, which was a time-of-use rate, it was quite attractive, it had savings opportunities, but you had to pay, you know, $4 a month in perpetuity, essentially, and it got 70,000 customers signed on out of 5 million customers. So that was the old-fashioned time-of-use meter.

So you will always find some customers will be willing to pay extra for a better meter, but it will be a very sparse deployment. You will not get any operational benefits from that kind of AMI deployment.

And in my experience, I've testified in several

124

AMI cases, most of the benefits are coming from the automation side of the distribution and sometimes no benefits are required from the customer side for the business case to pass. That was, for example, true for Commonwealth Edison in Illinois, but in most cases you need customer engagement.

For example, in New York, they did not have smart meters for a very long time. At some point, Con Edison decided to move ahead with smart meters and the condition that the commission laid out was, you need to have customer engagement because it was an expensive proposition.

So you can find examples of both kinds, but I would say the successful examples are the ones that are, by far and the vast majority, are the ones where you have regulators approving full-scale deployment.

But, of course, as Dr. Orans pointed out and the other experts have opined, it has to be shown to be cost effective within some reasonable degree of risk. There will always be risk.

The first objection is the cost is certain, the benefits are uncertain. The benefits have to be quantified carefully, shown, and shared with the stakeholders and, of course, they go through a regulatory process to gain approval. And then

125

sometimes the commissions will say, we won't let you recover this investment cost until you show us that the benefits are real.

That's what they did in Maryland. So the utilities were given five years in which to show that the benefits of the particular rate design they went with, which was peak time rebates, were sufficient by way of demand response in a PJM market to justify the investment. That was true for PEPCO, as well as for Baltimore Gas and Electric. It varies by jurisdiction as to how much of a risk is put on the customer versus the utility.

But, in any event, it has to pass the cost-benefit test.

MR. AYRI: Thank you, Dr. Faruqui. That was very informative.

I'm going to move over to the back-end data processing infrastructure, and I'm going to -- this is going to be for Mr. Friesen.

So, in your responses to the Commission's IRs, Mr. Friesen, you commented that some of the possible benefits of AMI systems depend on the level of sophistication of the back-end data or the back-end data processing infrastructure.

EPCOR's and other people 's responses to the

126

Commission's IRs seem to agree. It is this distinction between the basic AMI system and what we call "enhanced back-end data processing infrastructure" that the Commission was trying to make in many of its IRs.

So I'm just thinking, in the context of this third road map, you brought this up in the morning, what would you say is the timing for this enhanced back-end data processing infrastructure?

MR. FRIESEN: Thank you. To be precise about it, about the timing, or the timeline, for AMI deployment with an enhanced back-end data processing system, I think in some respects, defeats the whole purpose of the roadmap as it was defined by Dr. Orans in his submission, which was provided through Fortis.

The purpose of the roadmap in and of itself is to define the timeline and create decision points along that timeline that would trigger certain levels of activity.

So what could trigger those levels of activity? There are many different factors, but a few of them could relate to the desired tariff design or rate design; they could relate to the level of DERs penetration: The amount of solar PV, the amount of storage, the number of electric vehicles that are in the market.

127

As we seek some of the benefits that are available through the deployment of these DERs, and those benefits become substantive enough as the adoption rate grows, we need to make decisions about metering infrastructure and information management control and processing.

So the point I was trying to make is that the diversity of the benefits that were described in the IR are quite large. Some of them are achievable with the basic system, some of them required an enhanced back-end data processing system, and some of them go beyond the enhanced system and actually require realtime data management system, which appears to be a step beyond what you've defined as "enhanced." So, overall, I would say that timeline is very dependent on the pace and prioritization you place.

So, for instance, if you look at metered life, with meters in the field having a lifespan of, you know, 8 to, let's say, 12, 14 years, if you remove those meters from service early, you create a stranded investment. If you choose to roll out AMI in a manner that respects the life of the current meter installation, then you're looking at a timeline of a decade, plus or minus a little bit. That may not fully meet your objectives for obtaining the benefits that

128

are available through AMI, and you may choose to accelerate that.

So, you know, as Dr. Faruqui pointed out, if you want widespread deployment so that you can capture many of the benefits and you can provide optional rates for customers to opt into, you may want to do that in four to five years instead.

So I think all of us recognize that the deployment of AMI is not a small undertaking, creating the communication networks alone can be quite an expensive and protracted process.

So, you know, we're talking about a process that will, at a minimum, probably be at three to five years, even under an accelerated scenario, which may not be cost effective.

So if you look at all the factors that are involved and the direction that utilities or DFOs want to progress with rate design, et cetera, and combine that with the rate of the DER adoption, you know, a decade is not an unreasonable timeline for it to occur.

I think many of us would like it to happen a little earlier than that because it provides information and flexibility that does provide many benefits, but the DERs roadmap really is instrumental in setting those target points and establishing when to

129

move ahead with various levels of investments.

So follow the DERs roadmap process and I think you will come to a conclusion that's most beneficial to the ratepayer.

MR. AYRI: Thank you, Mr. Friesen.

Just to this point about the AMI system, the deployment of the AMI system, and with the DERs, I'm just thinking about the question of, can this full value of the DERs be realized without this AMI system?

MR. FRIESEN: If you're referring to -- that question to me, I wasn't sure if you were, but I'll take a first crack at responding to you.

I would say in its purest form or its most theoretical form, the answer to that would be no. We do require smart metering to fully realize all of the benefits, particularly those available through ancillary services, and some of the other benefits that are referenced in the IR. But that doesn't mean we need full deployment of enhanced systems to achieve all of those benefits.

If you look at, for instance, participation in the energy market, it really comes down to the requirement for settlement. So if you require settlement on an hourly basis as is required for large micro-generation and small-scale generation in Alberta, if you want to

130

extend that settlement practice down to small micro-generation, you will need to have an AMI meter in place. Now, how often you read that meter, and the method that you use to read that meter, will really determine what level of back-end system you require.

As EPCOR noted, you know, they read their meter monthly on a cumulative basis. If you are okay with settling monthly for small micro-generation, you could read that data, load interval data, once a month as well.

But you really have to, you know, determine what your requirement and that will determine your read frequency and it will also, to some degree, determine the capabilities you need in your back-end system.

MR. AYRI: Mr. Van Egteren has a question.

MR. VAN EGTEREN: So what I'm going to ask, I'm not proposing. I'm just sitting here thinking about -- I mean, this is a lot of money involved, rapid deployment, suggesting relatively short lives associated with these assets, and so to -- what I'm hearing is that, in order to garner the benefits, rapid deployment might be a good idea.

So what I'm wondering about is, is there any experience -- and I haven't thought this through deeply, so if this is obviously wrong, then please tell

131

me -- have any jurisdictions ever contemplated pre-collection of some of this, this money, so that you have a relatively small collection -- a longer time period for collection, and then you have the money available to have really rapid deployment without any sort of really big rate shock?

So I'm just wondering if anybody has ever contemplated that kind of scenario for rapid deployment of these kinds of assets?

Again, not suggesting anything, just wondering. Thanks.

MR. AYRI: Go ahead, Mr. Friesen. Oh, sorry. Mr. DesLauriers.

MR. DESLAURIERS: Thank you.

I'm not aware of any pre-funding, to answer your question, Mr. van Egteren -- I'm not aware of any pre-funding of such programs in rates prior to deployment, but I am aware of a number of rate and regulatory kinds of treatments that go to the effect of reducing rate shock and rate impact.

One of the experts mentioned earlier in this conversation the existence of potential stranded costs of existing meters that are replaced and, typically, what a utility will request is recovery of that through a regulatory asset. You know, the number of years to

132

amortize that asset doesn't necessarily have to be a short period, it can be amortized over a longer period of time to have a lower effect on rates, and so that's sort of one way to sort of soften the impact.

Another way to soften the impact is to gradually recover the costs in rates and defer some of those costs over time, and so that it's not a sort of an all or nothing or one-time hit to rates.

So maybe one suggestion to think about is, rather than pre-funding, to think about ways through the rate and regulatory process to sort of soften the blow.

MR. VAN EGTEREN: Okay. Thank you very much for that.

I'll get to you in a minute, Dr. Orans.

One of the other aspects of this problem that I've been thinking about sort of comes from the sustainability literature, and I think regulatory nimbleness is a really important factor, especially when you've got these random shocks in innovation, and Dr. Faruqui talked about that too.

So if you do have -- if you are pre-funding, then you have this in the bank. Instead of funding something that might be obsolete in a relatively short time, you now collect, see the landscape, and then deploy quickly, so that's part of what I have in mind

133

in terms of being nimble, but, anyway, just so you know.

Dr. Orans, please.

DR. ORANS: I agree. I think a roadmap is the nimble process. It reacts in just-in-time deployment, and I'm not bought in -- I don't want to leave you with the impression that you have to put in all the meters all at once to drive down the cost per meter of the back end.

I mean, if the value of the pricing deviations on the customer side is de minimis anyway initially, then, you know, you can't make it up in volume. There is no additional benefit per meter, there's just an additional cost.

And if the value initially is, you know, two-fold, it is grid reliability, vision, and interconnection, it just becomes more and more gradually the new standard.

I think you need to look at the Hawaii case, its failures, and where it did it right closely. So Hawaii initially proposed, just like everybody else, a big massive, swallow this big huge AMI budget, along with all the back end. The commission rejected it. And it was a tome filing. It wasn't -- you know, it was state-of-the-art filing five years ago. And it had all of these customer-related benefits, it had all the REV

134

stuff, everything was cooked in it. The commission rejected it without prejudice.

And when we filed it with a skinnied-down back end, about half of the back end they had before, not all the automation, not all the vision, partial deployment spread out, cellular instead of mesh network, which was higher cost per customer in application, and we got that approved. It's a small amount of dollars, broadly stakeholder supported.

And then immediately after that, the commission said, "Now send us your strategic pricing plan." Dr. Faruqui commented on that too, and he's been partially involved in this. And it's a phased pricing plan that works with the phased deployment.

It's funny, because the latest comments are, what's taking these guys so long on AMI? They don't realize they didn't want the full funding initially, we're five years down the road, and they're wondering how come you can't go faster. But there is a phased implementation.

You know, my own opinion is, I don't think it's -- I think it's unlikely that when you're done defining the cost-effectiveness approach, you're going to find a quick immediate hit piece with initial costs, all of it all together, to be cost effective widely in Alberta.

135

MR. VAN EGTEREN: Okay. Thank you very much.

Oh, Dr. Faruqui. Go ahead.

DR. FARUQUI: Just two comments to supplement what we have just heard. If you already have AMR in place, then AMI incremental benefits are substantially reduced, and that seems to be the case with a number of utilities, including ATCO Electric, so that has to be factored in.

Now, so suppose you find it to be cost effective, and the question is should you pre-collect? I have not seen that being done anywhere else. It's an intriguing idea. It's certainly something worth contemplating, but I don't know how a commission would ever be able to approve such a pre-collection plan with all the opposition that normally arises to charges for that pertain to things that haven't yet been done. There's enough of a challenge recovering costs for charges already incurred. So that's just my perspective.

However, if you think about what has been the cost where AMI has been deployed, based on the numbers I have seen -- and I'm by no means an AMI expert, I'm more on the customer side, but I do look at what the impact is on the customers' bills, it's typically been about $1 per customer per month, somewhere in that range. So it's easily dwarfed by all of the other

136

costs that are in that bill of the customer. It's not a huge number.

But in some places that collection begins simultaneously with the rollout of the AMI, and that's been my experience in most cases.

However, in some cases, as I mentioned in Maryland, they wouldn't let you collect it until five years had passed, they created a regulatory asset, et cetera, show that it was cost effective, and then you collected it.

But one big issue that I think some of the experts have mentioned, and I believe this is a challenge in Alberta from what I understand, that the issue is what about the cost, the unrecoverable cost, of the existing meters that have not lived through their full life, who will bear the cost?

Based on my experience, and it's not comprehensive by any means in this area, it's usually the customer. If the utility has to absorb that, it becomes a big deterrent, and that's something that I believe should be considered as well.

There is no real market value for those meters. You can't take your old meter and trade it in like a new car. Maybe there is a market in some other countries, but it hasn't yet manifested itself on eBay.

137

MR. VAN EGTEREN: Thank you.

Yes, Mr. Friesen, just one second, I just -- we do pre-collect net salvage here in Alberta, and it's an unknown future cost that is pre-collected, so that was sort of part of my tie-in there.

Mr. Friesen, if you're ready, jump in.

MR. FRIESEN: So I just want to address the pre-collection issue. InterGroup has participated in proceedings that have proposed to pre-collect. Generally been highly controversial for the reasons that Dr. Faruqui outlined, and raises real concerns about generational equity and collecting funds from customers who may never benefit from that collection.

So I think there's caution that we would suggest in that area, particularly in respect to pre-funding.

MR. VAN EGTEREN: Thank you. And I want to inform all parties that I was just sitting here listening to the testimony and it's just off the top of my head.

So everybody calm down, I'm not proposing this or anything. We had you in the room and I wanted to get your reactions to that. Thank you very much.

And, Mr. Faruqui, we are all too aware of the stranded asset problem here in Alberta.

MR. AYRI: Just one more question for Mr. Friesen, and then I'll just move on.

138

This goes back to the sophistication of an AMI system. I'm just wondering, how would the sophistication of an AMI system, whether basic or enhanced, how would that affect the provision of non-wire alternatives by DERs?

Did I address it to Mr. Friesen?

MR. FRIESEN: Sorry, I wasn't sure if you had addressed it to anyone specifically.

But I've always been of the opinion that, if you can't measure it, you can't compensate for it, or you can't charge for it, and that fundamentally is the basis of why we need smart metering to facilitate ancillary services. We need a way to measure them, they're typically time based, so we need appropriate interval resolution to measure those at services, as they're being delivered. And, you know, fundamentally, if you can't measure, you can't compensate or charge.

So, for that reason, you know, that back-end -- that more enhanced back end is required to ensure that you measure appropriately and charge or compensate appropriately.

MR. AYRI: Go ahead, Dr. Orans.

DR. ORANS: Just hopefully Mr. Friesen agrees with this.

You're not saying, Mr. Friesen, that you need full

139

deployment of AMI to all customers to be able to get telecom into distributed generators sufficient to do an NWA bid, are you?

MR. FRIESEN: No, I'm not. No --

DR. ORANS: Okay. I just wanted to make that clear.

MR. FRIESEN: I'm talking -- to be fair, and I'll clarify that statement -- obviously, deployment of those types of capabilities into larger generation sites is already quite common and is being done today.

I'm more talking about an environment where we're using behind-the-meter generation at the residential and small commercial level to provide -- you know, DERs at that level to provide ancillary services through aggregation and other means. So I'm looking at an environment where the consumer is being engaged quite heavily for provision of ancillary services.

I hope that helps explain what I meant.

MR. AYRI: Thank you.

So now I'm going to turn over to Mr. DesLauriers, and I'm going to ask a question about the responses provided in the Commission's IRs.

And it was regarding the deployment of AMI systems through the market forces, because you stated that you don't believe AMI services need to be provided on a

140

monopolistic basis by a regulated utility.

So could I get you to expand on that statement? What AMI services are you specifically talking about?

And then what are these other --

MR. DESLAURIERS: Well -- sorry, go ahead.

MR. AYRI: And then my other question was going to be, what other entities could provide these services?

I'll let you take it away.

MR. DESLAURIERS: Sure. You know, that statement was made broadly in the sense that, when we're looking at AMI services and we're speaking about data management, we're speaking about custody of billing data, we're speaking about aggregated data, we're speaking about a lot of information that's gathered from these systems.

And if we go back to some of the framework principles that we outlined in our report, you know, we do believe that there is a lot of value and competition and recognizing where competition and market forces can be brought into the delivery chain of the utility service network.

And, so, if we could conceive of a situation where the MDM and the communication system collects information -- and, of course, as we outlined in our

141

IR, we believe that customer -- protection of customer information is paramount, and the answer to this question assumes that those protections are firmly in place.

But the statement really goes to the thought or the idea that a utility itself isn't necessarily the only potential provider or user or disseminator of that information, so there could be potentially down the road an organization or an entity that serves to help facilitate energy transactions or other kinds of energy flows between the consumer and the distribution utility that could have access to that information and could provide information services as well.

We believe, obviously, that the T&D function is purely a monopolistic function, and that's sort of the structure of the setup and economic benefits it provides, but we don't see that that necessarily carries over to the management of the data itself and how that data is disseminated. It isn't necessarily purely a utility service in our sort of creative concept.

MR. REESE: I'm sensing some enhanced vigour after lunch, and I'll just remind people to speak at a pace so our court reporter can keep up and to keep -- answer as succinct as possible. Thank you.

142

MR. AYRI: Okay. Back again to you, Mr. DesLauriers.

Again, with one of your responses to the Commission IRs, because you indicated it was possible to implement these AMI systems without regulatory intervention, as was the case for some municipal and cooperative utilities in the United States.

However, the Brattle Group, E3 and InterGroup all stated widespread deployment could not happen without some form of regulatory intervention.

So could you just help me understand how these municipal and cooperative utilities implemented their AMI systems and to what capacity?

MR. DESLAURIERS: Well, I think our response to the question went to whether regulatory intervention in and of itself was necessary for AMI systems to be deployed, at least that's how we considered the question when we made that response.

And in our point of view, you know, if we've conceive of a municipal utility or an electric cooperative, they would have the authority to make those investment decisions just as they have authority to make investment decisions for their power supply and other portions of their system.

And so the response really just highlights, in our

143

point of view, that regulation in and of itself is not necessary as an implementing force for AMI purely from the example that, you know, municipal systems, non-regulated systems, are able to implement these programs without regulatory intervention.

MR. AYRI: Thank you.

Seeing no hands being raised, I'm going to turn it over to -- oh, go ahead, Dr. Faruqui.

DR. FARUQUI: Just a footnote on the municipal utilities and the cooperatives.

Yes, they're not regulated by state commissions, but they have their boards, and the boards have to approve their investments.

That is the case, for example, for Salt River project in Arizona or SMUD in California or any other utilities.

I mean, they have to show it starts beneficial to somebody, whether it's their board or regulator is sort of like a semantic issue. They are not being driven by free market forces. They are being driven by some kind of organized financial metering and rate design entity that oversees their operations.

So that's the comment I wanted to make.

MR. AYRI: Thank you.

Go ahead, Mr. DesLauriers.

144

MR. DESLAURIERS: Thank you. Just to clarify our response, and I think we make this response in our report with regards to AMI implementations, they're not regulated utilities. That was not to suggest that there isn't a cost-benefit analysis or an approval process that they go through at their level.

The only distinction that we make in the report is we assume that process takes place, but it's in a non-regulated rate environment per se relative to what we have in Alberta or with investor and regulated utilities for PUCs.

MR. AYRI: Thank you.

I'm going to turn it over to Mr. Bourque for another question.

MR. VAN EGTEREN: Can I just jump in there quickly, Mr. Bourque?

I just wanted to follow up with one thing with Dr. Orans.

I just wanted to assure you, sir, that we -- and I as well -- did make this connection between the regulatory roadmap and that nimbleness of the regulator. So just to confirm that to you, sir.

MR. BOURQUE: We have been speaking a lot about the cost-benefit analyses, and it raised a question for me that when AMI brings about some of these benefits,

145

that they might be hard to quantify.

For example, the benefits of improved rate design, removing load profiles or billing on an actual consumption data and their associated economically efficient outcomes.

So from -- and this is an open question -- from your knowledge of other jurisdictions, how would a regulator go about including such benefits into their cost-benefit analyses for AMI?

MR. REESE: Dr. Faruqui.

DR. FARUQUI: Thank you.

As I mentioned earlier, I have been involved in several of the AMI filings of utilities, sometimes called "business case," sometimes called "cost-benefit analysis." The first one was Pacific Gas and Electric Company in California; the next one was Southern California Edison. I was involved in both of those. And both of them had to show that the benefits exceeded the costs under a reasonable set of scenarios and assumptions. Both of those two utilities included a fair amount of dynamic pricing to create demand response benefits.

Now, keep in mind that market is different from the one you have. We're dealing here with largely vertically integrated utilities.

146

And so they were able to show that if you had 16 percent adoption rate for critical peak pricing, that was the case for PG&E's assumptions, then it passed; if you didn't have customer engagement, it didn't pass. And the same was true of the other utilities.

So the question was, how comfortable were people with the estimates of impact of these new innovative pricing designs. Initially, they were quite uncomfortable and, therefore, they formed stakeholder groups, working groups, and those working groups monitored very carefully the results of the analysis that the utilities were jointly doing to show that customer engagement was feasible and also predictable.

So they ran pilots with customers, large and small, two separate pilots, and it took two years to do that and then the business case filings took another two years, and then all was said and done, and then the movement began to happen towards deployment in 2007 onwards.

The same was true in Maryland.

In Connecticut, they ran a pilot. It showed good results. But the Attorney General wasn't convinced, thought the numbers were was soft, and so it -- the commission was not supportive.

147

In Massachusetts, they had AMR, and so AMI's incremental operational benefits were quite limited. They didn't even want to do pilots. And so despite having more PhDs per capita in the area of Boston, MIT and Hartford and whatnot, they still don't have AMI there.

It's a question of judgment, ultimately, and most people will do a pilot to test customer engagement, and we keep track of those pilots, and there have been, last count, 400 pilots done throughout the globe in the last two decades, but everyone feels they still have to do their own pilot because they're unique and different, their climate, their socio-demographics, et cetera, and so it varies by jurisdiction.

Economists only have so much influence on regulators, right, when all is said and done. And, ultimately, legislators are involved and premiers and governors. It's an issue of public perception as much as anything else.

You have a projection of the future benefits, but there is no guarantee that the benefits will be realized, so you have to somehow come together as regulators and take a vote on it, and then you decide to move ahead or not move ahead.

In Illinois, for example, they moved ahead without

148

any customer engagement benefits being counted because Commonwealth Edison showed that the distribution automation benefits were sufficient to cover the costs.

In Ameren's case in Illinois, they had to include customer benefits.

It's very system specific, it depends on whether you're rural or urban, it depends on whether you have AMR or you don't have AMR, and it also depends on the utility's interests and abilities along with the Commission or Boards, to think that time-varying rates can make a difference or that somehow AMI will enable more customer side benefits from being realized than if AMI was not ruled out. So it's partly subjective and partly objective and partly political.

MR. BOURQUE: Thank you very much.

I saw Dr. Orans.

DR. ORANS: I want to just add to what Dr. Faruqui already gave you as background.

So I would just categorize the initial wave of AMI and grid modernization, and what I would call the more than $10 billion of failed proceedings across North America on the whole thing based primarily on customer response as the major benefit.

And then there's a pivot in the, I would say over the last couple of years, to most of the benefits being

149

grid integration related and then a supplemental benefit being customer side.

Dr. Faruqui already mentioned that initially in what he was talking about, and it's particularly relevant to Alberta, where I think all of us have said we agreed with both of those.

So the two cases that I think you should look to for precedent on this is, Massachusetts did an extensive review of all of the benefits and adopted a broad standard -- we think actually way too broad -- but it has every category of benefits under the sun under it.

And then Rhode Island -- funny thing because Rhode Island sits between New York -- it's served by National Grid, who serves New York. National Grid is also in Massachusetts. And Rhode Island has a very progressive commission. It has studied all kinds of things and done nothing.

But you can use them -- you should look at their work because they've done lots of good work, and they've taken the Massachusetts set of benefits and narrowed them down to a defined set already.

So I'm not saying Alberta should use that. I would -- that's one big source of input I would direct for the group that would start in Alberta to refocus

150

itself on a benefit-cost approach that I would call more of the modern approach than going back and doing pilots on behavioural and on demand response, which aren't going to lead you really to much in Alberta in terms of short-term benefits.

MR. BOURQUE: Thank you very much for the additional colour.

I saw a lot of head nods there, so I feel comfortable passing it on to my colleague who is next to question, Mr. Vasetsky.

MR. VASETSKY: Good afternoon, gentlemen.

As the day goes on, you will see more and more AUC faces. There aren't too many of us left hiding in the background, so I think there is maybe a couple besides me.

I have a question for Dr. Orans.

Dr. Orans, I believe in your IR response you said something to the effect that -- I'm paraphrasing obviously -- if the regulator thinks that the cost of AMI is too expensive, one could proceed instead with simple forms of time-of-use demand charges rate.

And I guess my question is -- and maybe it's the question of definition, what one defines as an AMI. But given Alberta's situation where we don't have too many demand and time-of-use meters, how would we do

151

that?

DR. ORANS: I think this really goes to the previous question, which is, are we talking about back-end, are we talking about extended back end or are we just talking about meters.

And I think to get the robust, you know, Massachusetts set of benefits, we're talking about extended back end and meters; right? Because it's customer side and the whole thing. I think you should look at that.

At the same time, I'm not an all or nothing. You know, I think fixing the transmission rate design, fixing the distribution rate design, you know, basically fixing the credits, fixing the planning standards, looking at some alternatives for use of battery storage or demand response on a limited basis for non-wires alternatives, those are all incremental steps that don't have huge back-end, extended back-end, or metering costs.

So I think a roadmap idea is map out the benefit cost analysis, like Dr. Faruqui said, look at the customer side, look at the other grid-related side, and then talk about things you can do in the interim to move -- that each of the distribution utilities can move themselves along that roadmap on.

152

MR. VASETSKY: Right. And I guess another idea that I wanted to ask you, and the rest of the panelists, is, because there may be an opportunity for Alberta to sort of leapfrog, you know, because when we talk AMI system, you know, the price that you pay for the modern AMI meter, you get all of the functions almost as an added bonus; right?

So I guess my question is, is it worse -- in your idea of the roadmap -- is it worse for us to consider sort of more traditional demand and time-of-use meters or systems where one could just, arguably, for a little extra buck -- dollar -- get a whole bunch of potentially user capabilities?

DR. ORANS: I'm certainly not recommending you go invest in, you know, the old -- my first job at PG&E way back when I started, so more than 40 years ago, I designed the first time-of-use rate in California, Schedule D7. It was opt in. It was a Sangamo MTM 20 meter. It was $400 a meter. So I think Dr. Faruqui said it's a dollar a month now for the AMI meter.

I don't think this is an AMI metering issue. I would not recommend you go by iPhone 4s now. Maybe 7s? I'm not saying you need the new 11, but that doesn't mean you shouldn't go and proceed more generally on more efficient pricing.

153

AMI -- it's not AMI or nothing, and that's -- efficient pricing is not just all connected to AMI is my point, I guess.

MR. VASETSKY: A question for Mr. DesLauriers.

I got very interested in the discussion -- I believe you said something earlier that takes a whole bunch of -- in a way using simple words -- it takes a whole lot of money to set up a system for the first AMI meter to function.

Can you give us a rough idea, either in dollars or percentage terms if you have any experience, like, in terms of the total project cost, how much do you need to spend on the sort of fixed cost to get the first AMI meter running versus the incremental costs of putting the meters, installing them, and so forth?

MR. DESLAURIERS: Sure, I'd be happy to --

COURT REPORTER: Sorry, can I interrupt.

Mr. Vasetsky, you seem to cut in and out sometimes, so I didn't quite catch the end of your question.

MR. VASETSKY: I'll try to remember it now.

COURT REPORTER: Thank you.

MR. VASETSKY: I was asking Mr. DesLauriers if he you knows from his experience whether, either in percentage terms or in dollar terms the breakdown between the fixed cost of the system, the back-end

154

system, versus the incremental variable cost of starting to put the meters in.

MR. DESLAURIERS: And the response is, you know, as we pointed out in our IR response, every system is different, so we have to be very cautious of drawing broad conclusions of one system versus the next.

It depends upon the geographic scope of the system and how many meters and what kind of functionality and operation capabilities you're looking to build into the system.

But, you know, based on my experience and the programs that I've been involved with, in general, the amount of investment and time to set up what we would call that system backbone or back end, whether it's a mesh network or other network, as well as the data management system, the software, other hardware costs related to communications, first of all, in terms of timing, they appear to be a prerequisite, all of that has to be set up prior to that first meter being operational and pinging.

And, again, without, you know, looking at making broad generalizations, I would venture to say that those costs, you know, can be as much as 30 or 40 percent, 50 percent of the total system cost in some cases, depending upon the proportion of functionality

155

you're building into that backbone versus the number of meters you're implementing that will connect off of that.

So, certainly, to the extent that you can connect more meters to that existing infrastructure, that relationship can change, and it is very different for systems, but it's certainly not in the range of 2 or 3 or 5 percent and it's not 90 percent, but it's a significant portion.

MR. VASETSKY: Thank you.

And, Mr. Orans, you mentioned an example of the Hawaiian regulator where a company had to bring back the case with, I think you said a skinnier or a lighter back-end system. Was that to address the same issue, to reduce the amount of fixed costs upfront?

DR. ORANS: Yes, it was. I can confirm the discussion you just had.

So the five-year NPV spend for Hawaii was just under a billion dollars. I mean, that's a huge amount. You know, it was near several hundred million dollars, you know, a year. So that was the one that got rejected.

The back-end minimal piece with the opt-in slow roll on the AMI, the skinnier proposal, was between 200 and 210 (indiscernible) over five years.

156

So, really, not a huge amount, you know, in terms of rate impact. It was sort of what they could -- I mean, you start out with, what do you have to spend, and usually what you have to spend is, you look at what your depreciation looks like, and the depreciation head room gave them that amount to spend. So that's the back-end piece that they started with.

And then the AMI piece is how much did they -- would they get material benefits from on the operational side, and the people -- to go back to Dr. Faruqui's kind of comment, different customers have different benefits, and so the people -- the customers who saw benefits in getting meters and then connecting them to the back end, paid to opt in incremental metering.

So they had ones they socialized, that were needed, and then incremental opt-in ones that wouldn't cost additional customers more money.

MR. VASETSKY: Thank you. This is very helpful.

I would like to do something now to give you gentlemen a break and continue with discussion with the company who actually installed what we call a basic AMI system in Alberta, and I would ask my IT friends to connect EPCOR representatives if they're available. EPCOR.

157

MR. REESE: If there's a designated representative from EPCOR on the call, would you please raise your hand in Zoom?
MR. ZUREK: This is EPCOR.
MR. VASETSKY: Hi, gentlemen. A couple of quick questions for you -- and I apologize, this is going to be using some of the numbers that you provided in your IR response, so if I go too deep in the numbers, feel free to address these questions in your concluding remarks if you're thinking of filing any.

So, to put it in context, so EPCOR indicated that, to put your AMI system in place, EPCOR spent, let's call it, $76 million over a three-year term, and the back-end systems were configured in such a way as to basically continue with the same billing practice that was before; right? If someone was billed on a monthly cumulative basis, that would continue; if someone was billed on an interval basis, that would continue as well; right?
MR. ZUREK: That is correct.
MR. VASETSKY: So are you gentlemen --
COURT REPORTER: Sorry to interrupt. Can you tell me who at EPCOR is talking?
MR. ZUREK: Oh, I'm sorry. My name is Gerald Zurek. I am the senior manager of rates and

158

regulatory duties.
COURT REPORTER: Okay. Thank you.
MR. VASETSKY: Mr. Zurek, are you able to tell me, off the top of your head in context of discussion we had before, how much of the $76 million was spent on back-end system versus the meter installation costs?
MR. ZUREK: We actually don't have that detail in front of us right now. We can get that, though, and confirm at a later date.
MR. VASETSKY: That would be perfectly reasonable. Thank you.

UNDERTAKING - FOR EPCOR TO ADVISE HOW MUCH OF THE $76 MILLION WAS SPENT ON BACK-END SYSTEMS VERSUS THE METER INSTALLATION COSTS

MR. VASETSKY: And you also mentioned in your IR response, according to your rough estimate -- so I'm not trying to be super precise here -- according to your rough estimate, it's taken an additional $10 million to do a -- to enable an hourly read of meters for all customers; right?
MR. ZUREK: Correct. So that would be conversion of the current meters that are read or that are -- we have cumulative data for to obtain billing quality hourly data for.

159

MR. VASETSKY: And would that also include the possibility to do -- to implement demand charges or potentially time-of-use charges for energy, or is that a separate operation?
MR. ZUREK: It gets us partway, but it would require further expenditures to be able to actually bill in either time-of-use or in demand.
MR. VASETSKY: Okay. That's very helpful, gentlemen. Sorry for calling up on you in such a short notice --
MR. ZUREK: Okay. I can go a little further, because what that would give us is, it would give us hourly energy, and hourly energy is a proxy for the hourly demand. Essentially, the kilowatt hours in the hour is the average demand for that hour.

So that would give us some ability to then design a rate, but we would require modifications to our billing system and possibly our meter data management system in order to actually use that data to bill with a demand-type charge.
MR. VASETSKY: That is very helpful, Mr. Zurek. Thank you so much.

Okay. I just have one more question, and it is a question for the four experts here. And this is more of a general question, gentlemen.

160

We discussed this afternoon that AMI -- implementing an AMI system is not an easy decision and it depends on a lot of factors. It depends on the DERs penetration, it depends on the cost-benefit analysis, it depends, as Dr. Faruqui said, what's already in place here.

So seeing what you see in Alberta, you know, we've made some in-roads in terms of both the DERs penetration and there is some adoption of AMI technology in place, where would you say and what would be your recommendation on how to proceed with the AMI? Are we still in the evaluating stage? Are we already in stage 1 of your DERs roadmap, Mr. Orans? So what would be your recommendation? And I mean all four of you.

Okay, Dr. Faruqui.
DR. FARUQUI: So in the context of ATCO Electric Distribution, they already have AMR, they have a large rural population that they serve, and they don't have significant congestion on the grid based on the information they have provided me. So I think -- they're also proceeding with an AMI pilot in one of their communities.

I believe the best thing at least for that kind of utility configuration is to do the pilot to see what

161

the results look like, and perhaps at that point consider doing a comprehensive cost-benefit analysis to see under what conditions is the net present value positive, what would it take to justify the investment that would be required.

And based on my discussions with them, at this point, they have not felt the need to carry out a comprehensive cost-benefit analysis, so it has not been done, but the pilot that they're doing will provide insights that will help inform eventually such a decision.

Now, each utility has its own circumstances. Perhaps each company will have their own analysis performed. It's ultimately going to be an issue of what's the investment and what's the benefit.

I think Dr. Orans mentioned the $1 billion number for Hawaii in their initial filing. That really is high compared to what California ended up paying for the three investor-owned utilities, with some 10 million plus customers, the number was $5 billion.

So it's a question of, you know, local circumstances, it's a question of how costly is it to put it in. The state of Hawaii, beautiful and charming as it is, is definitely one of the most expensive parts of North America, but also a frequent destination.

162

Maybe it cost more because of that.

But the reality is, it is very utility specific. It's not province specific.

However, in Texas, they felt the need to move ahead with it because they felt without AMI you couldn't get a lot of those customer engagement benefits. Even though Texas didn't have a lot of DER penetration at the time, they are gathering momentum now.

DERs are one of those things that can happen very quickly. Right now, based on my limited experience, there's not much in Alberta, despite all the solar radiation they have in the summer months and the long days, there's not much EV penetration, because my understanding is gasoline is quite inexpensive.

And so there is also -- ultimately, the preferences of the customers who live there, how keen are they to become prosumers. Just besides the economics, there has to be an attitudinal shift.

All of those factors require, you know, further investigation before making a decision on what kind of AMI and at what pace should AMI be considered.

MR. VASETSKY: Mr. DesLauriers?

MR. DESLAURIERS: I agree with all that Dr. Faruqui just said. It is very utility specific and, you know,

163

there probably is a great deal of value in looking at it on a utility specific basis.

Just a few quick thoughts on looking at some of the benefits of AMI and how they may be or may not be capturable in Alberta.

If we look at the energy side, obviously, AMI provides the benefit of hourly metering, and so maybe one question to ask is, given the energy market in Alberta right now, is there a sufficient level of price differentiation on an hourly basis in the energy prices to make TOU pricing something of value to customers and of value to the utility.

There are certainly operational benefits from AMI, revenue leakage, automatic shut off and shut ons, those kinds of benefits that accrue outside of what's happening in the market that are also important to consider.

And we had a lot of discussion today on T&D and the value of T&D and the costs of T&D and scarcity pricing of T&D and the demand charges, but unless you know there is a situation where there is some real scarcity in either the transmission system or the distribution systems, the amount of benefits coming out of AMI from that may also be different. That's not to say that they're not there and that that can't be

164

constructive for deferring costs in the future.

So it really is a very utility-specific question and the benefits cut across many different aspects, whether it's operational, energy-related, fixed-cost related, and it really has to be thought of wholistically.

MR. FRIESEN: I don't want to take any of Dr. Orans' thunder away, but I do want to highlight, as I did previously, the value of the roadmap process that was outlined in his written submission, which was presented by Fortis.

The concept of triggers and enabling conditions, I think is very useful. They may not be universal for every DFO in Alberta, as Mr. DesLauriers explained.

The conditions for AMI may differ from DFO to DFO, and a properly executed roadmap provides that flexibility. It doesn't have to be one roadmap for the entire province. Each DFO can develop a roadmap that addresses their specific configuration and needs and objectives.

And, you know, by quantifying the specific triggers that require action to prevent negative consequences, you can then look at the forecasting you need to undertake to identify when the enabling conditions are present. Whether that's solar PV

penetration, whether that's electric vehicle adoption, whether that's energy storage implementation, you have a variety of conditions that you can identify and track and judge the pace and prioritization for your AMI investment accordingly.

I think it's a very rational and reasonable way to progress, and it provides the ratepayer, the DFO, and the regulator with a very transparent platform on which to make their proposals and gain approval. It's a very logical approach, and I compliment Dr. Orans on his submission. It was well done.

Thank you.

DR. ORANS: Thank you. I just want to add something short, Mr. Vasetsky. We didn't come to this idea ourselves. We were sitting in a room that long, hot summer in New York, and we had Con Ed. Con Ed, as the natural DSO, wants to do -- it is the furthest along in North America to being a DSO, and wanting to own and operate everything, and it's a big giant city; and we had Central Hudson, which was totally on the other end of the spectrum, and we were working on what is the DER integration strategy and what is the business model.

And the only way to get them under the same general state-wide framework, single regulator, right,

was to say, all right, let's toss this back to the utilities, have them tell the regulators what, where, when, how much, what technology, how much back end, where it makes sense to us, which one of our customers will opt in, et cetera -- now, I'm not saying the regulators are going to take all that and just let the utilities do everything. New York being New York will do some standardization.

But at the first step, I think, if you define the parameters, which is, I want to see it's cost effective, I want there to be a transparent methodology, I want it trackable, I want measurable things, et cetera, you can then give them the guidelines to make these filings that would form the basis of an integrated roadmap across Alberta.

And, at some point, they'll find out, like Hawaii, and what Dr. Faruqui said is, well, you've kind of gone one by one down this pretty far and you have inconsistent steps. At what point have you gone 40 percent of the way where we should just do the whole thing, I think that will become naturally evident over the course of this evolution.

And we don't know how fast that will occur, but I think if you start that process, similar to New York, similar to Hawaii, or Rhode Island, I think you're

going to find yourself along that roadmap and you'll kind of get to the right place at the right time rather than hurry up and get to the wrong place.

MR. VASETSKY: Thank you.

Oh, Dr. Faruqui.

DR. FARUQUI: Yeah, I just wanted to make a comment on Hawaii and New York, you know, two ends of the spectrum geographically speaking, with many similarities. I have been going to both states for at least 15 years to discuss pricing innovation and reform, and they keep talking about it and they keep talking about it and they hardly do anything.

So I hope that synchronizes Dr. Orans' experience.

Actually, a few years back, Professor Volag (phonetic) and I were both on a panel in New York when the REV was new and attracting a lot of excitement, a conference in the New York School of Law, and it was all on time-varying rates and the opportunities that await. It's just like watching paint dry at times and, really, you know, a scintillating experience.

So what I would say is the lesson learned here is don't analyze it to death. Have a roadmap. You'll have to take risks. There are no certainties about the future, only opinions, and so it will take some decisive leadership to move the ball forward.

I've been going to the Middle East, those countries have taken 25 years to do nothing, and I'm more than happy to be their consultant and get the hours billed, but the reality is it's like a soccer team, the people keep passing the ball to each other and never put it in the goal.

So, you know, that's the lesson that I have learned the hard way, that analysis, planning, and conversations are good, but sometimes you get caught in this cyclical struggle and then the commission turns over, the board turns over, new chairs are appointed, and we are back to where we were all over again.

MR. VASETSKY: Thank you very much. Dr. Faruqui, be careful for what you wish. Now, that you mentioned Professor Volag, you may actually see him in the next section, so...

MR. REESE: I believe Commissioner Romaniuk has a question.

THE CHAIR: Actually, two short snappers.

And I will direct this to whichever of the panelists has the most familiarity with the actual structure, design of pilots. I think one of you -- it might have been Dr. Faruqui -- said there are 400 pilots that they are aware of in their experience.

So the first question is, in designing a pilot

169

project as part of a process in determining the benefits, the demonstrable benefits of the rollout of AMI, is the objective to assemble a representative collection of customers, or a collection of the most enthusiastic volunteers or early adopters who are most likely to put the devices through their paces quickly and would be more likely to provide evidence of the actual benefits of the devices as opposed to, again, a representative sample, some significant percentage of which may do nothing with it?

DR. FARUQUI: A great question. It takes a lot of time to do justice to it, but at a very high level, realizing the break is coming up as well, it depends ultimately on what your full-scale implementation plan is.

So, referring to Dr. Orans' roadmap, every state has had such a roadmap. Sometimes it has never been published or shared, it's just been held in the minds of each person.

And when the California pilots were beginning right after the energy crisis, I was brought in, along with some others, to help design a pilot with the stakeholders and then the utilities would run it and then we would do the evaluation.

So the question that I asked was, what's your

170

vision of the end state? Is it going to be full-scale rollout? Is it going to be opt in? Is it going to be opt out? Is it going to be mandatory for the particular rates being tested which were time-of-use and dynamic pricing rates. There was no consensus among the three dozen people in the room.

So they ended up with a hybrid pilot, which was supposed to be representative of the population at large, but the people who were selected and given the option of saying yes or no -- and I was told that you cannot constrain people to be in the pilot against their will, it's unconstitutional -- and so that was one of the early pilots.

Much, much better pilots have been done since then, for example, most recently by SMUD and others, where they decided as a utility or as a commission or as a board, they were going to do randomized control treatment trials, just like a clinical trial for a new medicine, like for the pandemic vaccine that's being investigated. They're all RCTs. That's the gold standard of pilots.

You have a group that's randomly assigned to the treatment or the new rate here and a group that is acting as a control group, but the two of them didn't know which bin they were going to be in when they were

171

selected into the pilot.

That's a pilot that's expensive to do. It's a pilot that gives you results with a lot of confidence about being able to generalize from -- the pilot population could just be a few thousand customers to your aggregate population.

On the other hand, if you want -- if you have a vision where the ultimate deployment will be optional and the enthusiastic people, the prosumers, the energy efficiency geeks, et cetera, are your ultimate focus, then you need a pilot that mimics the behaviour of that population. So then you can go with voluntary enrollment.

That's probably the kind of pilot that a company like Starbucks probably does when it introduces new brands, new tastes. It's just looking for volunteers who are interested. It wants to see is there interest or no interest. If there's no interest, they'll move on to the next product.

So there's homework that has to be done at a policy level before the pilot conception can be laid out.

And the 400 treatments, the experimental treatments I mentioned, they're all over the place. Some are representative of their population and some

172

are not. Some are very poorly designed and some are very rigorously designed.

But even then, we have at least 100 rigorously designed pilots from other areas. Of course, their climate and topography and electricity prices are all different from Alberta's. As I mentioned, there is an AMI pilot being talked about. I think it has been approved for ATCO, so I think that would be worth looking at -- I'm not directly plugged into the selection of customers into their pilot, so I don't know whether it is the enthusiastic folks or it's a representative sample.

That's the kind of topic that I think for future pilots, if the roadmap concept begins to roll out, has to be factored in. How should it be designed, how large a sample should it be, what other analytical methods should be used to analyze the response of customers and all of that.

THE CHAIR: Okay. Thank you.

Does anybody else want to join in? I have one follow-up question.

Okay. Thank you for that very comprehensive response. It was very, very helpful.

My follow-up question is this: Given the concurrence among our experts as to the importance of a

roadmap, and the roadmap, you know, providing triggers, or the absence of triggers, for action in the circumstances, but the importance of the roadmap and the fact that we have had hundreds of pilots of every description to date, are pilots in fact necessary at all?

Can you get from roadmap, to the knowledge of outcomes from hundreds of pilots, to an application for either incremental staged rollout or continuous rollout without the need for, say, a year or two or a three-year pilot? Is it even necessary?

DR. ORANS: I don't think you need the extensive pilot studies of this. I think you can borrow, use, synthesize the other pilots to characterize what you're going to get on the customer side, as long as you're not going to bite the huge massive bullet right away.

If you're proceeding on this roadmap, go ahead and start, and then as you move through it, you're going to figure out what that definition, like Dr. Faruqui said, is, is it for this utility in The City of Calgary, is it everybody in rural areas, is it optional, is it -- and you're going to figure those out. And at that point you might want to test some, if the cost-benefit analysis hinges on it, or you might just want to roll

it out.

You know, I think one of the mistakes we've made in energy efficiency across North America is we spend about 40 cents of every dollar on energy efficiency in EM&V. That's pretty bad market, right, and we don't seem to improve our designs from it, it just has become its own world where we have to do EM&V on every light bulb installed, and I think -- and we're still doing that 30 years later when we know what the efficiency change on light bulbs and HVAC is and everything else.

So I think we've done, you know, through the good work of people that are on this panel, lots of work on pilots, I think we can characterize since the 1970s, you know, efficiency responses, time-varying responses, et cetera, within a range; and for the benefit of decision-making long-term -- remember, this isn't year by year, what am I making in hour X, it is over the next decade, what do we think these benefits could look like and the range, I don't think the pilots are necessary to get there.

THE CHAIR: Okay, thank you.

Ms. Collins, did you have anything you wanted to add before our break?

Okay. Mr. Van Egteren?

MR. VAN EGTEREN: No, but I think Dr. Faruqui put up

his hand there.

THE CHAIR: Oh, okay. I missed that.

DR. FARUQUI: Yeah, just to totally agree with Dr. Orans' statement.

Pilots are not needed most of the time except to buy time and to postpone the decision. I mean, that's -- I'm being cynical, with age comes cynicism -- and I have seen many pilots being done with no actions being taken. And with so many pilots already done, there should be the opportunity to adapt and innovate.

But, yes, if it's going to be a make-or-break question, then do a pilot.

And it might be that you have that, but you won't know until the roadmap is rolled out, some cost-benefit analysis is done.

In California also, in the early 2000s, they did not want to do a pilot initially. Well, somebody came in and said, we have inclining block rates and none of the previous pilots had inclining block rates. And so we need a pilot on top of inclining block rates to see if customer behaviour changes or doesn't change.

And when the pilot was done, and it showed significant response of 13 percent reduction in peak, when you had a critical peak price, it was five times higher than the average rate, the debate became, is

13 percent big enough or not big enough; and my response was, in the double digits, it could equate to thousands of megawatts. Now, you might say 20 percent would be bigger than 13 percent.

So it's a question of, if you want to move forward, you'll have to make some judgments anyway at some point in time.

But, believe me, I've tried the argument in many cases and been told we need a new pilot. And, believe me, right now, more pilots are happening throughout America.

But there is one example I want to mention to you where pilots were not done, and that's your province of Ontario in Canada. The Premier McGuinty just decided AMI was a good thing and needed to be done, and so AMI was rolled out in Ontario -- I actually reached out to him because I was doing the California work at the time, and I asked him for a cost-benefit analysis to see what parallels I could draw; he said we don't need one here.

So, you know, it's a question of what are the various factors in the roadmap, and his roadmap action was more important than doing pilots.

But ten years later they are now doing pilots to make sure they did the right thing ten years ago.

177

THE CHAIR: Very good -- very good informational vignette. Thank you for that.

I'll tell you one other thing that comes with age, Dr. Faruqui, I found out at Christmastime on my last vacation, $5 Tuesdays at movie theatres. So when you hit that magic 65, all those discounts just come flowing in your direction --

DR. FARUQUI: Believe me, that happened two years ago.

THE CHAIR: We're at exactly 2:30. Now, we will come back in 20 minutes and we'll work from that point to the end of our session, however long it takes.

Thank you very much for a very productive first half of the afternoon.

MR. VAN EGTEREN: I have one other thing to say --

THE CHAIR: Oh, sorry. Go ahead.

MR. VAN EGTEREN: -- while we're still here.

I couldn't help but be struck by all of your comments regarding progressive leadership, and I agree with progressive leadership. Everybody's in favour of progressive leadership until it results in a decision that is not in their favour.

And so I hear your comments, but there's a process, and so that's what we weigh.

Thank you.

178

DR. FARUQUI: May I make a comment before we close, just a very quick one to just follow up on the remarks you just made?

So Michael Peevey was the president of the California Commission for two terms for a total of 12 years, and he was the presiding commissioner over all of the AMI hearings, all the dynamic pricing work, an enthusiastic supporter of that.

But it still hasn't happened, and it's been almost 19 years now that we would have default time-of-use rates in California, but no real dynamic pricing or realtime pricing.

And so I thought I should ask him words of wisdom now that he has been retired for five years, and his answer was, "We did our best, but we had other priorities," which was perhaps another way of saying what you just said, and basically he said, "There was no strong advocate for doing it, not in the legislature, not the governor's level and, therefore, it didn't happen."

So, I mean, it's sort of -- he was basically saying the staff of the PUC was not interested, and I said, "But you were the president of the commission." He said, "Fair point." It's published. I mean, it's not a secret conversation. It's in the Fortnightly.

179

THE CHAIR: Thank you for that.

Anything else to add from any staff members?

MR. REESE: I'll just note that we're breaking for 20 minutes; is that correct?

THE CHAIR: Sorry, yes, that's correct, and I will extend it to eight minutes before the hour.

Okay, we'll see everybody in 20 minutes.

(ADJOURNMENT)

THE CHAIR: Welcome back, everyone, for today's virtual meeting.

I think we will begin with one question sort of in the nature of follow-up from Commissioner Collins.

MS. COLLINS: Thank you, Commissioner Romaniuk.

I would like to just have a high-level discussion about how to best incentivize our distribution utilities that are operating under performance-based regulation, PBR.

I found the many submissions on current and proposed incentives very insightful and especially pertinent today, given what we are trying to do with this inquiry, to encourage real change and implementation of technology that's needed in this fast-changing electricity world with intermittent renewables, smart technologies, new options to help customers get more out of the grid.

180

I recognize that many parties made submissions in this regard, I think all of the experts did, and I will highlight the submission from InterGroup's Mr. Friesen, that: (as read)

"A PBR framework for DFOs should develop ways to integrate emerging customer needs and innovation requirements into a modernized regulatory framework, a PBR framework, to support transformative innovation, to provide reasonable substitutes for the incentives, risks and rewards facing unregulated markets undergoing transformational change."

If you would please just take a moment, and I'm happy to hear briefly from each of the experts, to highlight how to best incent innovation under our current five-year PBR plans.

And I guess I'll start with Mr. Friesen, and thank you.

MR. FRIESEN: Thank you.

I think one of the criticisms that I heard come through in the various submissions that have been provided throughout this Distribution System Inquiry in respect to PBR have been primarily focused around the backward-focused nature of the PBR process where the

181

target costs that have been established for successive five-year terms have largely been set based on historic performance in the previous five-year terms.

And while that is maybe a suitable approach in a static environment with minimal change occurring, it struggles a little bit to address a world with transformational change.

And as the DFOs argued or presented in their submissions, they feel that they're entering a world of pretty significant transformational change with the anticipated adoption of DERs and not quite sure how to fit that into the current PBR framework.

So do I have an answer for you? Not an immediate one. It's an issue that we've somewhat started to examine, but I'm not sure we have a very strong position on it, other than to state, we need to look at the impact of transformational change and the costs associated with such change on the PBR framework, and make sure that there are mechanisms in there that encourage DFOs to look forward at ways -- or look "proactively" may be a better term -- proactively at ways of integrating DERs, capturing their benefits, and, you know, becoming more customer centric in their overall framework and in their operations. If we continue to do what we've done in the past, we won't be

182

well suited to responding to the future.

And I think somewhere I once read a quote that, "Walking into the future while facing backwards is a precarious situation to put yourself into." And I think that's really what I'm mentioning here -- or referring to here, is that we need a forward-looking perspective within PBR that helps the DFOs focus on both the benefits of DERs in addition -- or on the benefits of DERs in addition to the costs.

I think almost universally when I read the DFOs submissions, I felt that there was a heavy emphasis on the costs of DERs and the costs for integrating DERs. It was almost at times appeared to be fatalistic and with very little emphasis on how to explore those benefits, how to capture those benefits, and if we could modify the PBR approach to put a reward mechanism in there for capturing those benefits, I think there would be some incentive for the DFOs to pursue those more aggressively and examine, you know, various states of deployment for AMI and, you know, various levels of back-end systems and explore more innovative rate structures that support the integration of DERs.

So, you know, for now, that would be the position that we would take and the view that we would have in respect to PBR. I think PBR in itself has been

183

something that the DFOs value tremendously. I think, for the most part, they've been highly supportive of PBR and feel that it has been a positive thing for them, but I think the current format of PBR has some aspects to it that various parties are now finding constraining given the nature of change.

Having said that, and when we talk about transformational change, I think we need to be careful in playing chicken -- what is it -- Chicken Little on this one, "The sky is falling, the sky is falling." As has been mentioned at various points, DERs adoption in Alberta is still in its early stages. We have some time here. We can take a measured approach. We can examine this in detail. We can look at the examples from other jurisdictions and learn from them and do this in an orderly manner and thereby hopefully avoid some of the mistakes that have occurred in other jurisdictions. We don't need an answer tomorrow.

MS. COLLINS: Thank you, Mr. Friesen. That's very helpful.

Is there anybody else who would like to add anything? Otherwise we can move on to the -- oh, I'm sorry. Dr. Orans.

We can't hear you, Dr. Orans.

DR. ORANS: I agree with Mr. Friesen's

184

characterization of the cost and benefits. I think one of the problems with the benefits is they're back-ended and long term and the costs are short term, and your PBR is short term.

But just one idea is, you know, if you're convinced that over 10 or 20 years the benefits are bigger than the costs, you can make an adjustment to the baselines in the five-year time frame to re-adjust the baseline framework in your PBR, and perhaps then you could get that in place as a long-term glide path and way to implement this under your PBR framework.

MS. COLLINS: Thank you, Dr. Orans.

Dr. Faruqui, I saw your hand up.

DR. FARUQUI: Yes, thank you.

I just wanted to cite the example of the state of Illinois where they have essentially a PBR-type approach, and for years, there was not much of an incentive for Commonwealth Edison, the utility, with something like 3 million customers to do much in terms of customer engagement, and so they created performance incentive mechanisms sometimes called "PIMs." Many utilities with PBR are being encouraged by the use of PIMs, P-I-M-S, to do more customer engagement, like energy efficiency, demand response, DERs, all of those kinds of things, so that creates a win/win opportunity.

185

And so what initially might look like, oh, why should I do this as a utility, I will lose business, I will lose revenue, I will lose earnings, my shareholders won't be happy, to a situation where, well, your shareholders could be happy because you now have a win/win situation.

I think one of the key concepts here that I know the other experts have also mentioned is customer centricity. The customer is changing fast, maybe not in Alberta, but they will change fast in five years, certainly within ten years, they have changed everywhere else, and those customers are going to drive the change, so there's an opportunity for the utilities and the AUC to get the customer engaged in this conversation so that they don't bypass what are part of the change.

How do you do that? Well, you have to create those performance-incentive mechanisms for the utilities. Meaningful and feasible PIMs can lead to significant change.

So I just wanted to make that comment.

MS. COLLINS: Thank you, Dr. Faruqui. I think the customer side is very important, so thanks for adding that.

And, Mr. DesLauriers, I would like to hear your

186

perspective as well.

MR. DESLAURIERS: Yes, thank you. I agree with all the experts' comments on this topic. I just wanted to add that -- and we echo this in our report -- is there may be an opportunity to rethink the risk/reward continuum for utilities under PBR as they rightfully begin to consider the value of innovating and meeting the evolving nature of customer needs.

I think -- I know in North America, and in particular in the United States in the jurisdictions I've worked heavily in, there's often the emphasis of a backward-looking prudence review to justify investments that have been made by the utility, and when those reviews, you know, aren't met with favourable results for cost recovery, it's a disincentive for that utility to continue to try to innovate in some of those particular examples.

And so one suggestion in PBR is maybe an evolution in PBR, as we're looking at innovation, is possibly rethinking where that risk/reward balance is and providing some opportunities for the DFOs to take risks to innovate with proper controls, obviously, for rates and managerial outcomes.

But I believe that might make the PBR, as we're going forward into the evolving utility world, I think

187

that might make PBR the risk/reward ratio such that utilities might be further incented relative to what's in place today to make some of these innovative investments, and they most likely are in the best position to evaluate which of those will work on their system.

I just wanted to impart that thought.

MS. COLLINS: I'll turn it over to Commission Member van Egteren. Thank you.

MR. VAN EGTEREN: Thank you very much.

So we do have some experience with this kind of thing here in Alberta related to EPCOR's deployment, investment in AMI.

And so one of the issues -- well, first of all, if the -- the planning horizon for anything, the investment in anything here is in fact longer than the PBR period, then there's every possibility that, during a PBR period, the incentives might be not to minimize costs. Okay? So we're aware of that.

And so the company comes forward, they've got a -- you know, an excellent business case, say, and it's got net present values calculated and showing very positive things, but the problem is it extends over the course of the ending period of a PBR term and so there's all this uncertainty associated with rebasing, then you've

188

got issues here.

So is it -- is one simple solution -- and I'm not proposing this, right -- but is one simple solution to make the timeline on the disconnect between revenues and costs simply longer; that is, the PBR term is longer? Is that a reasonable compromise in some sense? Because you're always going to get some investments that will extend over the arbitrary demarcation of end of PBR term. They just have to be thought of and you arrive at these investment decisions a year before the end, and so that's always going to occur.

But do you mitigate some of the issues there if you simply extend the PBR term?

DR. ORANS: I don't think you can extend it long enough. I mean, I think price cap or revenue cap or formulaic rates are really good at incenting utilities to drive a short-term efficiency and cost reductions.

I think long-term bets on new technology are just -- I've never seen it in my nearly 40 years in the business. Any pipes or wires company under a PBR who has done any kind of long-term strategic technology investment -- I can't think of one under a PBR framework. And so even if you -- and, you know, I can't imagine them living under the DIAC (phonetic) for

189

15 or 20 years. So usually it's five years, maybe six or seven, squeezed down, get efficient, and then rebase like you said, and look at the things they want to bring in and then go on another one.

I was thinking of an interim way is keep your framework, you know, the five-year framework, and then potentially allow a utility -- if they can make their cost benefit case longer term, to rebase in the term only for that amount, not everything else. So here's the rebase required for the net benefit piece and for me to -- and I might not implement the whole thing, but at least a piece of it during that five-year period.

MR. VAN EGTEREN: I understand.

Any other comments?

MR. FRIESEN: I think one of the things, you know, with PBR you have to create a baseline of some kind to measure against, and in a time of transformational change, establishing that baseline out five years may already be a challenge. Extending it to seven, eight, nine, ten years is -- you know, it becomes almost impossible in many respects if that change is substantive enough.

So I think you're going to run into a lot of controversy about what the new baseline should be once you're looking eight, nine, ten years or more out. So

190

that's also a consideration in lengthening the PBR time frame.

MR. VAN EGTEREN: Sure.

Okay. One last thing on this because I don't want to derail this, but this is a really interesting area for me.

There are those who would argue, and who have argued in the past, and I'm not an expert in this area, but I've heard this phrase a lot, that there are -- within the X factor, the way in which it's developed using the data set that it's used, there are instances in that history where they perhaps have had transformational change.

And so in setting the benchmark here, which we'll call the X factor, and given the flexibility you build into your PBR framework hopefully, are there enough checks and balances in there given the fact that this kind of experience might be in the X that you don't have to do anything? Simply let the system work -- okay.

DR. ORANS: It's possible, but none of them are doing huge amounts of back end for right now.

So I'm sure there's something in there. To say it's zero is not realistic, like you say. There's something in there. It's hard to tease out what

191

exactly that amount is, but it's -- but your point, I think, is a good one.

If, in setting the baseline, if you're doing it again, you know, could you pick a different period, you know, of maybe even a longer period as the baseline that includes some transformation in it that's akin to this so that it has some of that growth, natural growth in it, that includes new technology.

MR. VAN EGTEREN: Okay, I will end it there, but I suspect this might be a topic we'll visit again in the future, but thank you very much for your comments. Very informative and helpful.

MR. REESE: Were there any other Commission Panel member questions?

If not, I will turn it over to Mr. Vasetsky who has some follow-up questions from our earlier discussion.

MR. VASETSKY: Thank you, Mr. Reese.

I just have a couple of questions, I want to take you back to the rate design or tariff area, and I want to do it so we are very clear on what -- that we didn't miss your recommendation.

So I'll start with Dr. Orans.

Dr. Orans, you mentioned in the morning that perhaps an ideal way or a better way to price a

192

distribution network cost is to do it on a, I believe you said distribution planning zone basis; right?

DR. ORANS: I was talking about basically connecting causal costs, you know, with load.

MR. VASETSKY: Right.

DR. ORANS: I didn't extrapolate and go as far as you said and say it made sense for Alberta to do distribution zonal level pricing. I was following the argument basically on how do you do that.

MR. VASETSKY: It's always nice when someone answers your question before you ask it, but that was my question. I just wanted to make sure that zonal pricing was not on the table at this time.

DR. ORANS: Not from me.

MR. VASETSKY: Okay, thank you.

The second clarification I wanted to make is I believe what I heard from each of you gentlemen is that, so if we go to the next step of having a two- or three-part tariff where there would be a fixed charge to recover the embedded costs and there would be some form of a variable charge to send that deficient price signal, I believe I heard that you said that doing it on a time-variant basis would be an improvement over just coming up with the, you know, static three-part tariff.

193

Did I hear it correctly?

DR. FARUQUI: I'll give you my perspective.

I think the variable element for a distribution utility should be a demand charge that is time varying. I still do not see the role of an energy element or a volumetric element in a distribution charge, which is not to say that it is not on the list of options, it's not just the first best option, it would be a second best option, where you price distribution costs volumetrically, as you do today, but you go one step further and make them time varying.

To the extent that there is time variation in the cost for the distribution system, peak versus off peak, you can offer time-varying rates, and that's what one utility in Australia and one utility in New Zealand are doing. They would much rather do time-varying demand charges, but they don't have the support with the regulatory bodies or the politicians to introduce a demand charge.

But Con Edison has a pilot underway where they have the time-varying demand charge, they also have made it available to anyone else who wants to opt into that demand charge, and they did see a lot of cost justification for having time-varying demand charges.

In Arizona, we have that as well for the two

194

utilities, APS and SRP.

So that's kind of, I believe, realistically the best option, but if you can't get it, the second best is a time-varying energy charge, and the third best is what is there currently, which is a fixed charge plus a volumetric charge. That's what's been there for a hundred years.

MR. DESLAURIERS: And this is David DesLauriers.

I would agree with that, with what Dr. Faruqui just mentioned, but I would say that my recollection of that question, we discussed it this morning, was in the context of the three-part rate that Charles River had been one of the recommenders on.

And in terms of going back to the principles of cost causation and cost recovery, I believe that the variable charge thought was that that should be tied as closely as possible to the energy market, we know that that varies by time based upon the fuel costs of the source of generation.

And so we do think that there's a time-based component to fuel and to energy charges, and that's obviously clearing in the energy markets today through the AESO. And so, you know, our statement was that energy charges correctly priced should reflect those price signals and most likely a time-varying energy

195

charge would be better than one that aggregates it all and averages out across time.

DR. FARUQUI: May I ask a question, just a clarification question?

So the time-varying energy charge makes perfect sense to me, but what I'm trying to reconcile is how does that influence the pricing or distribution services as opposed to energy services?

MR. DESLAURIERS: I think we're getting confused on what we're pricing out. There is a supply component of what an end user pays through rates, and so I completely agree that I believe, on the distribution side, those costs are primarily fixed and could be recovered from a demand charge in a three-part rate.

My focus on the energy piece is on that supply portion. That supply portion, the value of that supply does vary by time, it has a different nature to it from a cost point of view.

DR. FARUQUI: Oh, I agree totally. I just wanted to be sure that that's what was being mentioned.

But my understanding was that the supply portion of the rate, in a competitive market like Alberta, is left with the retailers and doesn't fall within the jurisdiction of the Commission. Maybe somebody can comment on that.

196

MR. FRIESEN: I was actually going to make a comment related to the energy component of the bill.

It is interesting that Alberta has an energy market, an hourly energy market, that's competitive, yet very few customers at the residential or at the distribution level actually take advantage of that time-variable capability, and -- and I'm sure there are some, but when I looked at the -- you know, I took a moment awhile back to skim through the offerings of the various energy retailers, and there are very, very few time-varying options available. Almost everybody is offering, you know, one, two, three, five-year kind of fixed-rate options for energy.

So you have an energy pool in Alberta, and it is a time-varying rate, an hourly time-varying rate, and that price signal is largely absent from your market, at least in terms of the residential consumer or the small C&I consumer.

So, you know, there's an opportunity there, I believe, to introduce customers to time-varying rates within a market mechanism that you already have in place. You don't have to invent a new market mechanism.

Now, one of the challenges you may have is legacy metering, and we've talked about that and I won't

197

expound on that any further, I think we all understand what kind of constraints that may impose.

On the demand side, when we're specifically looking at distribution tariffs, I agree that, you know, capacity is the driver, and a demand charge is the best indicator of capacity causation and -- or the best link to capacity causation, cost causation, and my only concern would be that we don't lock ourselves into a short-term view of the fixed nature of distribution costs.

At InterGroup, we do not subscribe to that philosophy. We feel that sending a fixed charge price signal to a customer is a meaningless price signal. It provides no opportunity for customer response. It provides no opportunity for customers to manage their bills, and that is a distinct right that all customers should be provided with. They should have the right to manage their bill and they should have the ability to respond to a price signal.

So, for that reason alone, we're not a fan of fixed charges, no matter how -- no matter how fixed you view those costs to be in the short term. We would like a demand charge to have a forward-looking component so that we can -- or that customers can impact the future of the grid, and the future cost of

198

the grid, to the benefit of all ratepayers.

So, with that caveat, we would agree that a demand charge that is time varying would probably be the most effective in conveying a price signal to consumers for distribution expenses.

MR. VASETSKY: Go ahead, Dr. Orans.

DR. ORANS: Mr. Friesen, this is the first time I've heard a real difference with this group, at least on my side. I was about to say I think we're all in agreement on the framework.

I -- I can't agree with what you've just said is, I think what you've just said is, regardless of what the variable costs look like, you want a variable cost charge that's bypassable, and I can't agree with that.

I would agree with what Dr. Faruqui said is, we can convince ourselves there's an avoidable part of distribution, and as Mr. DesLauriers said, there's an avoidable part of energy supply, it should be time varying, and that makes sense.

But what I can agree with is that if there isn't an avoidable piece in the relevant time frame, that we differentiate that and put that out as a target to be shot at. It doesn't make any sense to me economically, it doesn't make any sense from an equity point of view.

MR. FRIESEN: So I'll try to clarify what I said

199

and what I meant.

When I said "variable," what I meant is that there needs to be a price signal that consumers can respond to, that through a change in their behaviour, can assist them with managing the physical quantity of their energy bill.

So by that I don't mean uneconomic avoidance. If they're purchasing a service, a capacity service from a utility, I fully expect the consumer to pay for that service, I believe there's an accountability aspect there, where if you draw a service from the utility, from the distribution system, you should pay for it.

But the point I'm making is that, if you can modify your behaviour and change the nature of the service that you're drawing from the utility, and that reduces the costs for the utility, you should be rewarded for that.

And that is what I mean by the term "variable." I'm not trying to imply that we should allow people to avoid costs for services that they draw from the utility. That's not at all what I'm advocating for.

My bigger comment was related to the fact that I'm in favour of a capacity charge, but I do not believe that that capacity charge should be viewed on a short -- or be set based on short-term -- a short-term

200

view of fixed costs.

I think it should be based on a forward-looking perspective that enables changes in consumer behaviour to reduce the overall cost of operating the distribution system through reductions in their capacity requirements as a result of the price signal, their response to the price signal that's being provided to them.

Does that help a little in clarifying what I meant?

DR. ORANS: Yeah, I just thing it muddies the record from what we said this morning a little bit, is I thought, following Dr. Faruqui's characterization of distribution systems, we agreed that the majority of the costs are fixed for the relevant time frame we're talking about.

So let's just say it's -- let's say it's 80 percent, for example. So those should be something like a non-coincident, you know, peak demand charge, connected load. It's principally not for avoiding, it's principally just cost allocation, equitable allocation to a customer for their use.

And then there's another piece, perhaps time varying if it makes sense, that's this time-varying demand charge that is something, like you said, is the

201

long-term avoidable cost of that system.

I thought that's where we -- the central agreement was. I just didn't want to make -- I wanted to make sure you weren't backing up over that record that we already established.

MR. FRIESEN: No, I'm not trying to back up on that record.

What I think I'm doing is addressing a behaviour -- utilities are very bureaucratic in their construct, I think I'm safe in saying that, having worked in one for 29 years, and we have a tendency to repeat -- and I'll use "we" in the context of when I worked in the utility -- we had a tendency to repeat what we were being rewarded for.

And if we were being rewarded for investing in new distribution infrastructure, we continued to invest in new distribution infrastructure and found whatever means we needed to justify that.

And I'm looking for a way to reward utilities for behaving in a way that encourages consumer behaviour to mitigate the need for new investment.

And I'm concerned that if we focus too much on this 80 percent over the one-year rate application or the two-year rate application being fixed, we're just going to reward embedded costs and not really prevent a

202

strong enough price signal to positively -- positively influence reductions in distribution spending or new investment in the distribution system going forward.

MR. REESE: Mr. Vasetsky's last question has generated considerable discussion, and I just want to check in with him, if he's finished with his line of questioning, then if we're ready to move on to Mr. Lucas's line of questions?

MR. VASETSKY: I think we do. Thank you very much.

MR. REESE: Mr. Lucas.

MR. LUCAS: Thank you.

So throughout the day today we've heard quite a bit about this idea of a roadmap.

And, Dr. Orans, in your written submission you expressly recommended a roadmap contain two elements, those being triggers and enabling conditions whereby you described all market participants would be able to monitor the triggers, and if a critical mass of triggers was met the distribution utility and its stakeholders would then need to enact any enabling conditions to allow for the evolution of the utility and the successful integration of DERs.

You also this morning brought up how you arrived at that as part of a broader team or process and

203

contrasted Central Hudson with I believe it was Con Edison, and how they were at different places in their own development or evolution of their system.

So, Dr. Orans, can you please comment on the advantages and disadvantages of instituting a generic roadmap for all distribution utilities with similar trigger points and enabling conditions, or directing DFOs to design their own roadmap with either individual triggers or individually tailored triggers and enabling conditions?

DR. ORANS: That's a very good question, and I'm not sure I have a great answer for it, but I will try. I invite my esteemed colleagues here to jump in if you see it differently or if you can improve upon this.

So I'm hoping that the Commission doesn't walk away from this and say, okay, this is all in your court distribution utilities, tell me about this roadmap and enabling conditions and tell me about what your triggers are, and I'm going to basically put it all back on you and you're going to tell us this stuff and then we're going to see whether that's good enough and respond to it.

So I think there are a number of concrete things you can do to make this -- make their filings better.

204

Those concrete things really, to me, look like, what does a cost-effectiveness test look like and what do I need to see, what are the measures I need to see here, what are the categories.

It's almost like you need a -- you need to come out of this decision with some more concrete -- I mean, ideally, it would be a white paper saying, here's our vision of the roadmap, here's our characteristics, we don't require you to do those.

But it's sort of like what FERC does for US utilities. Here's the FERC standard, is, you can fit your thing exactly to it or you can vary from it and improve it depending on your circumstances.

And I think it's worth the Commission going through, thinking about what it would like to see in the filings, helping and using other filings from other places that we've all mentioned to inform that so that people can get somewhat more standardized than, come one, come all, come all sizes with different triggers.

MR. VAN EGTEREN: So, Dr. Orans and Dr. Faruqui, would that imply something like the specific form of, say, a cost -benefit analysis as an informative piece on the roadmap?

DR. ORANS: Absolutely. I think that's where a lot of places have started is, what's in and what's

205

out, what can we quantify, what can we take credit for, and then as you aptly brought up, and then how would it get fit in a baseline under the existing structure, et cetera.

If you could start that conversation with them in your decision, I think that would be helpful towards standardizing responses.

MR. VAN EGTEREN: Dr. Faruqui?

DR. FARUQUI: Yes. I wanted to say that, what I have discovered through many stakeholder processes is the first thing is to get the definitions down: What is DER, what is an NWA, what are costs and what are benefits, and I have discovered that the terminology alone takes a day or two to sort out. And then you have to find common ground so that everyone agrees that they are talking about the same concept.

Then comes the task of, how do we quantify these categories of costs and how do we categorize these categories of -- how do we quantify these categories of benefits, and that's another round of discussion.

Because people have different backgrounds, they have different interests, they have different histories, they have different knowledge of what's happening elsewhere and what's working and what's not working. So a lot of infrastructure meetings need to

206

be held to create the common ground.

And then comes the task of where do we get the data to measure costs and where do we get the data to measure benefits, and you form subgroups, and then you allocate the assignments to them to come with the quantities that go into that algebra, if you will.

So it is partly a process of trying to find common ground and partly a process of doing the analysis, but you cannot do the analysis without doing the common ground or people are talking past each other.

MR. VAN EGTEREN: Thank you very much to both of you.

MR. LUCAS: So my follow-up -- my prepared follow-up to that was going to be, what are the next steps following the inquiry that the Commission should pursue, if we did pursue this idea of a roadmap.

But I heard Dr. Orans just say we should -- the Commission should write a white paper and define some of these things and kind of set -- kind of benchmark like the FERC might do.

And I heard Dr. Faruqui say, I think, something almost totally different, rather than write a white paper ourselves in the Commission, to form a bunch of working groups and subgroups.

Is that fair? Did I catch that correctly from

207

both of you.

DR. FARUQUI: Let me comment, it certainly is not orthogonal to what Dr. Orans was saying. It's just a question of, at what point do you write the white paper, how extensive is the white paper, is it conceptual, does it lay out some ideas on how the analysis will be done, and then invite comments. Or do you first do the conversations and then write the white paper. And it's a bit of a chicken and egg and it just depends, really, on the emotional temperament of the AUC.

DR. ORANS: Again, I hate to keep coming back from these cases, but we can learn from them since we were all in them, we can do better as we go through them.

So all the REV documentation in New York gave pretty good white paper roadmapping for what the utilities needed to come back with, and probably went overboard, so that's too much, right, on the regulatory side.

At the same time, you know, the Hawaii case, you know, it was very strident in its rejection of the utilities' vision and mission, and it told it not what to come back with, you know, but it didn't fill out what it wanted to see.

208

Like Dr. Faruqui said, what does it really want to see, it would be useful for you guys, and maybe that is definitional, maybe it is methodological, what is -- you know, what would be required for you to see to basically give you enough evidence when they come back with something more concrete, if they could work on it.

What the utility did in Hawaii is really interesting. So they were given six months after they had got a total strident rejection. They said go back, talk to stakeholders -- they had a massive stakeholder process -- and come back with a proposal to us -- remember, they had the billion and then they -- so, obviously, the stakeholders said, you need to shrink the costs way down, that was part of the cost-effectiveness evaluation, and you need to have an opt-in component, you need to show clear benefits, categories.

So they didn't have much opposition to their plan when they came back because they did six months of stakeholder compression work root stuff before they got to the commission. The commission case was pretty narrow on, you know, a few people that stayed out on a few issues, but they basically told them, come back with something that your broad stakeholders can support before we look at it.

209

So I think that looks to me like the discussion we had this morning, I don't remember who said it, but somebody other than me said, broad stakeholder support for whatever you bring back to us on your roadmap and your strategy and your evaluation.

MR. LUCAS: So help me out further as I conceptualize this. So you laid out some kind of areas where we may want to set triggers or trigger points, and, obviously, those would be defined in this collaborative process if we went down that road that you suggested.

But, at the end of the day, if they're going to be monitored as key indicators of when we may need to implement an enabling condition, they would need to be quantifiable. And when I read your submission, I had a hard time figuring out how you would quantify some of your suggested triggers. Can you help me think through that, please?

DR. ORANS: Yeah. So there are some that are already -- that are relatively easy like interconnection requests, interconnection queues, right, amount of credits, amount of upgrades, amount of DER being installed; right? Those, to me, are all things, Mr. Lucas, that you could put up on a portal, right, and just have normal reporting on those things.

210

The things you can't do that you should be doing is also this cost of the inefficient rate design and cost-shifting piece. You know, how much is flowing through -- if you've got a poor design but nothing is happening and it all -- you know, so what? There isn't a bunch of people making bad investment decisions, you know, long term and it's not that big a deal. But you can quantify the damage done with rate design that isn't, you know, appropriately reflective of costs.

And, you know, that will be also a trigger for, I'm losing 50 million a year, I'm losing a hundred million a year, customers are making X, Y, and Z investments based on those decisions. Oh, this $200 million investment now looks to be -- it triggers a, "please file a case to correct this," right, when you see those numbers.

Right now, it's totally not transparent, those numbers. There's nowhere in Alberta where you can see what the potential bypass is of the transmission 12 CP rate, for example, or the various distribution companies, you know, designs that are largely volumetric that we just talked about. I think you want to be tracking those too and I think you want the utility tracking those, regulators tracking those, customers tracking those, to determine how fast and

211

whether the investment in the back end, the extended back end, and the AMI meters and the rate design, you know, make sense. I think those numbers, you'll be surprised in some areas could grow quite rapidly if you're not watching them, if you're not addressing them in a roadmap fashion.

MR. LUCAS: Just to follow up on those comments, doesn't that -- by quantifying what the bypass might be, wouldn't that be suggestive of what I think Mr. Friesen referred to earlier this morning, that all bypass being bad? Is that what you're suggesting? If you're quantifying bypass -- no, okay, I misunderstood.

DR. ORANS: No. I think you want to look at how many customers are making investments in behind the meter gen. I agree with the statement that a lot of them do it for liability reasons and, you know, that's fine. And they get improved service, they get back-up service. All of that is fine. I think you want to look, though, is there a bad design also sending another incentive that customers are paying for.

So I don't like it that some customers are paying for some -- partially some other customer's increased reliability either. So that's another triggering thing.

212

You're never going to have perfect rate design and you're going to be constantly tweaking it. I think cost shifting is a measure that utilities don't do well. They don't show it to anybody. It's not popular to show your customers that, but I think that's what we're really talking about.

Are customers able to install behind-the-meter generation? And I like it that they're able to do it and interconnect and benefit themselves, but I also like the concept of what I think of as margin neutral rates. I want the distribution and transmission natural monopoly utilities to be indifferent between whether they do that or not, and the only way you get them indifferent is have margin neutral rates. Their margin and their total rate levels. They don't need a rate increase or decrease as associated with.

MR. LUCAS: So the last question on this topic while I have you and we're able to get your insights on this. So what would you recommend -- or how would you recommend addressing trigger points that may have already been triggered and implementing enabling conditions? And perhaps this is something that would be worked through in any kind of stakeholder process.

DR. ORANS: I think those triggers -- I think those triggers are more important to some people, less

213

to others. And I think the litmus test is does it go into the cost-effectiveness evaluation. And if it does, how is it counted? As Mr. Friesen said, is it really long term or is it short term? Is there a reliability piece that we didn't count? I think all those are in play in this work group that would define these. And I think the Commission has a major role to play.

There won't be uniform agreement in what the methodology is; right? And the Commission can be -- to use Dr. Faruqui's term, it can look more like a leadership position if it looks super long term. It can look more conservative and business focused if it looks shorter term.

I think each issue will bring its own definitional case and the Commission can reach some reasonable balance of what makes sense in the long and short term in terms of is this -- is this something it wants its utilities to lean into earlier or later than it would otherwise.

MR. LUCAS: Thank you, Dr. Orans.

I just want to canvass the other panelists, if they have anything to add to this matter because -- yes, please, Dr. Faruqui.

DR. FARUQUI: I want to comment on the issue of

214

cross-subsidies between customers, which clearly has been the flip side of the coin when it comes to DERs. Some customers have high bills, they invest in these technologies and they lower their bills, to the point that maybe they're not covering their fair share of the capacity costs of being connected to the grid.

They're more than happy to see the reduction in their bill. Their bill used to be $200 a month. They have dropped it down to $10 a month. And they're sort of having, you know, barbecue parties and they're bragging about how much their bill has fallen. And sometimes I'm at those parties before I put my solar on my roof and I'm trying to tell them that, you know, it costs $50 to connect you to the grid. And they're saying, oh, that's just nonsense, that couldn't possibly be true. They're just making money off me. I'm a net zero customer. Why do I have to pay the $10? But that's the perception of those customers.

Then you go and talk to the other customers at some other barbecue parties about the fact that they are subsidizing those other customers. And, interestingly, most of them don't know, number one. Number two, they don't care.

And the apathy for the cross-subsidy argument, one, the public is huge. I was talking to a utility

215

CEO on the East Coast as to why is it so difficult to bring about change in rate design to minimize those cross-subsidies. The utility is trying to help one group of customers who are currently paying a hidden tax without knowing it.

And his response has stayed with me. He said, we are regarded as a regulated monopoly. We are not regarded as a company that anyone likes or is friendly to. So when we try to say we are doing the fair thing, it doesn't have credibility.

I am just mentioning it because it is a challenge. How do you deal with the cross-subsidy issue?

Let me just make one other analogy. Let me switch over to energy efficiency for a moment, which was mentioned earlier.

Billions are being spent on energy efficiency. When the US, when the movement began, the economists argued that you should use the ratepayer impact measure test, or RIM. So if rates go up as a result of the energy efficiency programs, you wouldn't do those programs. Well, that was when I began my career. Around the same time as Ren Orans.

And 20 years later, just about everyone switched to using the total resource cost test, or the TRC test, which basically ignored the cross-subsidy argument. It

216

said as a cost-benefit analysis the benefits exceed the costs, we're going to do it.

And so about ten years ago in Florida I was working for a utility on a project to look at different ways of looking at cost effectiveness of energy efficiency programs. And they use the RIM test in Florida. They're the only state out of the 50 states that use the RIM test today. And they wanted to see if there was some other way of proceeding with it.

So I reached out to my local utility, where Ren Orans used to work and where I have been a customer and consultant, to Pacific Gas and Electric Company. I asked their head office -- the DSM, I said, what do you say to a customer whose neighbour put in an efficient air conditioner and half of the cost was paid for through a rebate by the utility and their bill really went down and you didn't see any benefits. Actually your rate went up a little bit because you have to pay that person's rebate.

So I asked Bill Miller that question. And Bill Miller said, the RIM test has not been mentioned in California for 20 years. Interesting you bring it up.

I said, yeah, but please answer my question.

So he said, well, we tell that customer, you had

217

the opportunity to put in that efficient air conditioner yourself. It's still there. So why don't you do it next year.

So, in other words, the cross-subsidy argument for energy efficiency has been long forgotten. At least in the US that's the story. I don't know what's in Canada. I'm just saying we have to -- as part of the triggers it should be there, but I don't know how much weight to put on it.

MR. REESE: Thank you, Dr. Faruqui.

I see Mr. DesLauriers has raised his hand.

MR. DESLAURIERS: Thank you. I just wanted to respond to all this good conversation about cross-subsidies.

I would say that, you know, my experience was a bit different in terms of utility apathy and/or customer apathy with regard to cross-subsidies and DER. I was pretty heavily involved with the net metering rate debates in Arizona back in 2014, '15, and '16, where sort of the debate about cross-subsidies and net metering was at ground zero at that time.

And, you know, there are ways to quantify what the cross-subsidies are without having measured them by meter, there are ways of working with load profiles and with production profiles, meters, and assume kW size

218

and number of installed facilities, and within the existing framework to really come down with a pretty precise calculation of what the cross-subsidies were that were going between classes -- I'm sorry, customers within the residential class.

And so, you know, I would just like to remind that, you know, I think I respectfully disagree when we say that, you know, customer apathy and utility apathy really isn't there. I think once the dollars become known, that those cross-subsidies and those shifts become pretty significant. And that really goes back to also the conversation we had about quantifying what some of these triggers might be.

And, again, even when it comes to residential DER and solar PVs, there are ways to quantify what those impacts are, and we've done those studies where we know exactly at what point you need to have penetration of DER by a certain kW, and size and account that will create a certain dollar amount of cross-subsidy.

So I think there's a lot of good work that we can do in a roadmap that Dr. Orans suggests. There's a lot of quantification that can bring a lot of informed insight into those questions.

MR. REESE: Thank you. This question has generated considerable discussion, and I see more hands

219

being raised, but I just want to check with Mr. Lucas if he has any further questions to ask on this topic?

MR. LUCAS: No. That concludes my questions. Thank you.

MR. REESE: Okay. I invite the further remarks that you were looking to bring in with the hand raising to be part of your written submissions.

And, at this point, Commission staff has concluded its questioning and thanks to the four consultants for their answers today.

I would now like to check in with Commissioner Romaniuk to see if there are any Commission Panel questions.

THE CHAIR: I do have the two related questions, and then I'll turn to Mr. Van Egteren and Ms. Collins to see if they have any wrap-up questions before we complete today's virtual meeting.

This question -- and I'm very sensitive to the amount of time we have available, so this is a big sweeping question, and if members of the panel feel more comfortable addressing it in their client's final comments or their own final comments on behalf of their clients in mid July, that would be perfectly welcome, or if you're comfortable and confident that you've already addressed it in the entire span of your

220

submissions to date, written submissions to date, that's fine too.

And, finally, the third alternative, if you have a really short crisp response that you would like to put on the record of today's event or today's meeting, that would be fine too. It's just that we really don't have that much time left for expanded answers.

So, with that by way of introduction, let me just qualify the question.

We have two fundamental realities in the distribution world. One is that electric distribution systems are natural monopolies, I think we've actually had two of our panelists actually use that term in today, Dr. Faruqui and Dr. Orans, I believe, both spoke to the natural monopoly nature of electric distribution systems.

And the second foundational premise of regulation of electric distribution systems is the governing legislation in Alberta which places considerable emphasis, if not primacy, on the FEOC principle: fair, efficient, open competition.

Indeed, if I'm not mistaken, Charles River Associates -- I'll be looking at Mr. DesLauriers here -- as one of its principals in its March 13th written submission was to, I'm quoting here, "simulate

221

outcomes of competitive markets," which kind of fits in nicely with what the Alberta legislation speaks to.

So my first question is, on what basis or using what criteria will we be able to assess over time, so, again, in a dynamic setting, whether and to what extent the monopoly's electrical distribution grid is and continues to be optimally, that is, efficiently, resourced, configured, augmented, upgraded, managed, operated, and utilized in the public interest?

And I'm going to skip right to my second question because they're related.

What regulatory, that is to say public interest policies, should be followed and given effect...

MR. LUCAS: Sorry, Randy here in Edmonton. Excuse the interruption, we lost volume, if Commission Member Romaniuk was still speaking.

No, we still can't hear anything from Calgary, and I see from Dr. Orans that he can't hear anything either. The same from Mr. Friesen.

DR. FARUQUI: I can't hear anything either.

MR. DESLAURIERS: I heard the last portion of Commissioner Romaniuk's question: What policies should be filled and given effect...I'm just reading my pen scratching, but I heard two questions. Did I get that all?

222

MR. LUCAS: That's where we lost his, what regulatory -- that is to say public interest policies that should be given policy and effect, and that's where we lost the feed.

Mr. Reese, can you try your microphone? No, we're not getting anything from Calgary.

I'm going to hand it over to Mr. Van Egteren, who I think will try the question.

MR. BOURQUE: We're having a short technical problem with the audio in the Calgary hearing room, so if you'll bear with us for just one moment, please.

MR. LUCAS: Okay.

MR. BOURQUE: We are proposing a very short five-minute break. So we will adjourn until one minute after the hour. Thank you.

(ADJOURNMENT)

THE CHAIR: I must confess that I am much relieved that I didn't touch any buttons to make what happened happen. I usually am the cause, but in this circumstance I was not the cause, so I am relieved, and I'm also happy to see that people can hear.

So what I'm going to do is, I'll just repeat the second part, which is very, very close to the first part, except for the introduction.

So the second part of the question was: And what

223

regulatory, that is, public interest policies, should be followed and given effect in ensuring that the monopoly electrical distribution grid is being resourced, configured, augmented, upgraded, managed, operated, and utilized on an economically optimal basis in the public interest over time.

Just as a final sort of qualification, for all the other parties that are on the line that are participating in this event but who are participating as listeners, I would welcome any and all to the extent that you wish to respond to those questions, comment on those questions in your final submissions in the middle of July as well.

So having said that, I will look at the panelists. And if any of you have anything you would like to say either in response to that or, you know, by way of any kind of qualification or elaboration, bearing in mind that we have about 25 minutes or so left in our scheduled time, I would welcome hearing from you.

Okay, I'll start with Dr. Faruqui and then Dr. Orans. And if Mr. DesLauriers and Mr. Friesen want to say -- or add anything else, I would be more than happy to welcome your comments as well.

DR. FARUQUI: Thank you. So what I believe will need to happen, based on all of the discussions you've

224

had today, I think everyone is on the same page that change is coming. And even though it might not be evident today in Alberta, it is extremely likely that in the next five to ten years the landscape will look very different, with a lot of DERs, a lot of new digital technologies. All of those mean that the utility regulated monopoly that we have today will not look at all like what it will look like in five to ten years' time.

Because if it doesn't move, if it doesn't change with the times, it will see more and more customers defecting as batteries and rooftop solar and other devices like micro-grid and CHP come into play.

So the utility will have to redefine its relationship, in my view, with its customers. It will have to reinvent itself. And I believe the best way to do that would be for the utility to become customer centric, which basically means that the process of regulation will have to recognize that and give utilities that opportunity. So that might mean in many cases perhaps the utility doing new functions than what it has done in the past.

For example, in Illinois the utility ComEd is interested in improving the reliability by installing micro-grids. In other cases utilities are interested

225

in owning charging stations for EVs. And still in other cases utilities are interested in somehow initiating the PV revolution by doing community solar or doing solar projects where otherwise nobody would be focusing on them.

So there are big gaps in coverage today between what the utility does and what it could do. It will require a reinterpretation of the regulatory compact to redefine the utility's role as the market changes. Otherwise it will become increasingly less and less relevant to what's happening inside the customers' premises.

And one last thing I will say, it might even mean that in those areas where there are reliability issues, the utilities might be encouraged to install storage devices. And that is already happening in places like Hawaii and New York and California and Montana.

So I believe the regulatory compact will have to be flexible enough to adapt to the dynamic changes in how electricity is being consumed and not just in how it's being produced.

Those are my comments.

THE CHAIR: Thank you very much.

Dr. Orans.

DR. ORANS: Thank you for the question. I

226

think it is at the heart of really what this case is about. And I would agree with your characterization that a distribution system remains a natural monopoly, but in parts of it it's becoming more and more what economists call "contestable." So what we've got is a contestable natural monopoly, if you will. It's not by any means a workably competitive market. An interfacing with a natural monopoly is a difficult situation.

The case -- and I would love to see what Dr. Wolak kind of could bring to your decision in terms of what did we learn from railroad regulation. Railroads had incredibly average politically derived tariffs for years and years and years and they were the backbone of economic development. And when they became contestable, the other forms of freight, trucking and air, they got cherry picked all over the place and their rates went through the roof. They became non-viable at that point as a system.

And I think -- you know, I believe that electrification is going to be the biggest thing that hits this wires business, you know, over the last hundred years: electrification of transportation, electrification of buildings. So I see 30, 40 years down the road, you know, levels of load that are 2X.

227

So I fundamentally believe what you said, it remains a natural monopoly. But I also believe there will be many more DERs and lots of ability to control all the new electric uses.

I think 15 years from now when you plug in an end use, it will have an IP address and it will be controllable and you will have some kind of smart interface on the ability to control it.

At that point, Dr. Faruqui, I'm not worried about the complexity of the design. The interfaces will take care of it. And, at that point, absolutely all of Alberta should have all the back-end, the extended back-end, and the metering to be able to even allow access and use of all that stuff.

So it's not too early that you're having this proceeding, if that's what you're thinking, and it's not too early to start and have the roadmap and the triggers. I don't know all the details, but I know pieces that I think we all have agreed to today is adopt a flexible, non-risky but aggressive in its own way roadmap that is triggered by the things that you care about. Use the years of experience in other competitive markets that Dr. Wolak can help you write in the decision that is like a white paper for guidance for what utilities should come back with on their

228

cost-effectiveness evaluations and what they should do with the back-end material.

Move pretty quickly on efficient rate design. That doesn't mean you need to do all the metering at once. But I think to the extent you can move on efficient rate design, I think moving quickly on that rather than later is going to prepare you for basically all the steps in the roadmap.

And then I think this alternative wire service, even though it might not be huge right now, the biggest technology change that we're going to see, you know, in the next five years is battery storage. And battery storage is already basically predicted to be competitive with gas, you know, within five years for peaking capacity and generation systems. At some point it's going to be a cost-effective supplement, not total substitute but supplement, for distribution and it would be too bad if Alberta can't catch part of that wave and include it in their distribution operations as well. So it seems like an alternative wires efficient procurement process would be part of your roadmap.

THE CHAIR: Thank you very much for those comments.

Mr. Friesen.

MR. FRIESEN: You know, in principle I agree

229

with, you know, everything that we've been -- that's been shared with us to this point.

I might have one little exception with Dr. Orans in respect to the impact of electrification. I think we sometimes forget how efficient electric vehicles are and how persuasive energy efficiency has become. And if electric vehicle consumption replaces the gains we make through energy efficiency, I think we may have a net sum zero, or very close to that, in the future.

You know, I remind people continuously the amazing things about electric vehicles is not that they're electric, it's that they're three to four times more efficient than a fossil-fuelled powered vehicle. So the total share of energy that they require to do their job is substantially less, and that will not translate into the level of load growth that some of us seem to feel will occur.

But my summary statement is that we'll know that distribution system is working optimally when we can measure the performance against the customer need. And the customer need is changing so we have to develop metrics for performance that optimally reflect the customer need, and then measure that performance on a continuous basis. And that will be done through the regulatory process, as it is today, and it will be done

230

by customer response to what rate -- what regulated utilities provide.

Grid defection is not a myth. It is a real possibility with the technologies that are coming down the road and it's very difficult to bill a customer that isn't connected. And if utilities do not respond, if the integrated electric system does not respond appropriately to changing customer behaviour, grid defection will become real. That will be the true litmus test for the industry, to see whether they've adopted appropriately to changes in technology and customer behaviour.

But that would be my summary.

THE CHAIR: Thank you. That was a very, very useful perspective as well.

And, Mr. DesLauriers, I have not forgotten you. I was just kind of clearing the decks left to right on my screen and you were just in the next row. Your turn.

MR. DESLAURIERS: No worries. I have the distinct disadvantage of being the last to speak on this topic. With so many good things already spoken, I probably don't have a great deal to add, but just to reiterate our position on this.

You know, when I first jotted down some of the metrics that you were asking about in your question

231

regarding configuration and resourcing and overall optimization of the grid and when can regulators and consumers and when can we know when that is really calibrated well and when that's not. And I think, you know, answering that question right now is extremely difficult. I think we all know when it's not working. But answering the question of when it's working or how much better could it be working, as Mr. Friesen points out, is still a question that's out there. And I think that there are a lot of metrics that still need to be developed as we go forward into electrification that can help us answer that question.

So I share the urgency with my other panelists. I think that electrification is happening and that there needs to be a new generation of metrics evaluation requirements to measure just how well that monopoly approach is working.

And then just to reiterate our preamble in the report and the quote that you said the question about simulating market conditions, we continue to believe that there will always be a role for T&D utilities, even with electrification, that there is a natural monopoly that exists in a regulatory contact that they operate under, and that will continue to be a role that is important all the time. But we also believe that

232

where market forces can provide input and can provide an influence over development of new technologies, we think an important regulatory policy is to allow those forces to occur where they can occur naturally, and that the interaction of market forces will produce an outcome that we believe will be valuable and possibly better than what would occur under a pure monopoly approach.

So those are just some closing thoughts on your question with regards to the monopoly position of the grid.

And then one other thing that I haven't heard yet, but obviously I think is behind all of our comments is that being technological agnostic I think is an important sort of assumption to this approach. That if we do leave market forces to develop, those market forces will in effect, as we outlined in our report, naturally develop those innovations that make sense to consumers and make sense to utilities and that we don't really see that there is a role for regulators per se or utilities per se or any one individual per se outside of market forces to encourage one technology over the other. As we stated, we know there are a lot of technologies out there and they're all competing with each other and they're all in some regards

233

advancing at rapid rates. And so we just advise that we let market forces play out where they can.

And that concludes my comments.

THE CHAIR: Thank you. Very, very helpful as well.

I'm going to turn over to my left here. Commissioner Collins, any last questions or comments?

MS. COLLINS: Thank you.

I don't have any further questions. It's been an extraordinary day. I've really enjoyed hearing from all of our expert panel members, thank you so much and, yeah, that's what I had to say. Thank you.

THE CHAIR: Thank you. And Commissioner van Egteren?

MR. VAN EGTEREN: Thank you. I don't have a question. I'm going to save questions for another day, but I would just like to make a comment, and some day we'll have this conversation hopefully with similar people in the room.

We've mentioned let markets do their work, Mr. DesLauriers, you've mentioned -- we've mentioned FEOC principles, we've mentioned implementing changes according to the concept of efficiency, and then we had a discussion just recently about cross-subsidization, and it reminded me of the -- and these are the kinds of

234

things I often think about -- it reminded me of -- the cross-subsidization discussion reminded me of the two definitions of efficiency that I'm aware of.

So in your earlier days, Dr. Faruqui, the idea was that if people were worse off, then that was a bad deal, but later on it came -- a different consideration was given to whether or not something was implementable or good, and that was the cost-benefit analysis in which, in fact, if the benefits were greater than the costs, you could implement a solution like that, even though some people were worse off. And, to me, this represented the two definitions for efficiency -- and I recognize that this is esoteric and I'm almost finished -- the two definitions of efficiency based on Pareto as opposed to Kaldor-Hicks.

And so when I come to think about these things, implementing it based on markets, and we understand the theoretical underpinning of implementing things through markets is based on Pareto efficiency as opposed to Kaldor-Hicks, and then we talk about doing cost-benefit analysis, which is based on a different definition of efficiency, which is Kaldor-Hicks, and we've got comparability and measurability issues, and all of those things.

And so some day I would like to have that

235

definition about, are there consistent theoretical underpinnings for what we are doing based on the different definitions of efficiency.

So I'll end my comments there. Thank you very much.

THE CHAIR: Thanks very much, Commissioner van Egteren.

I'm going to look at Mr. Reese here. Any wrap-up comments before I go into my closing remarks?

And just the staff members, anything else that we may have left on the table that we want to clear up?

Seeing none, hearing none, I will go into my closing remarks.

So just like we did in Red Deer for Module One of this inquiry, we tried something new today, and I hope everyone's computers and Internet connection worked throughout the discussion today, except that one unfortunate part where it didn't, and that you feel is a valuable information exchange. Nevertheless, we would welcome your feedback on how today's meeting went from a technical perspective.

I'd like to express my appreciation to Commission staff for preparing this meeting and taking care of all of the organizational issues, in particular, a big thanks to our local IT guru, I'm looking over here to

236

my left at Mr. Scott McCallum for pulling this off for us. From my perspective, other than that one little glitch when I was talking, things went really, really well.

I want to thank everyone else for taking time out of your busy schedules, making yourselves available for today's virtual meeting, and I do especially want to thank Mr. Friesen of InterGroup Consultants; Dr. Faruqui of the Brattle Group; Mr. DesLauriers of the Charles River Associates; and Dr. Orans of E3. Your comments, your insights, your thoughts were very, very instructive, informative, helpful. Gentlemen, you distinguished yourselves today, and we thank you for that.

It's been a long day for you, and we appreciate you helping us gain a better understanding of the issues we discussed today. Today's conversation will help Commission members greatly as we continue to consider the regulatory framework necessary to accommodate the emerging economic and technological forces poised to effect utility distribution systems.

As described in Exhibit X0649 in this proceeding, 24116, all parties are invited to provide concluding remarks for the Combined Module by July 15th. These remarks should be brief and not raise new issues.

Concluding remarks should focus on parties' responses to the discussion that took place today during the virtual meeting, but, more importantly, we would like to hear your thoughts on what you think an ideal regulatory schedule would look like. We asked this question of our four panelists today, and I know some parties have made comments on future proceedings in their written submissions. So now is the chance for the rest of the parties to do so if they intend to file concluding comments.

A key outcome of this inquiry will be to establish the regulatory agenda for subsequent proceedings that will consider and then implement the regulatory framework necessary to accommodate the emerging economic and technological forces we have been discussing.

So I look forward to hearing everyone's perspectives in your concluding remarks on the order in which we should tackle these issues. For example, based on what was discussed today, should the Commission undertake a rigorous cost-benefit analysis, as was suggested by several of our panelists, to determine whether AMI should be widely deployed; should the Commission launch a generic proceeding on rate design for the DFOs to harmonize rate structures

to bring them more in line with some of the things we heard today; or do we need to focus on other issues that were not discussed today like energy storage ownership rules and metering or how we should deal with distribution connected generation, DCG, credits. These are just some examples of the issues we've heard over the course of the inquiry, but you get the idea.

We at the Commission look forward to receiving your best advice on how we should structure the regulatory agenda that follows the completion of this inquiry.

After we receive parties' concluding remarks, that will complete the information-gathering stage of this inquiry. My expectation is that we will issue a report on the inquiry in early fall of 2020.

Once again, thank you all for being here and for your participation. Please stay safe, everyone. Good evening.

(PROCEEDINGS ADJOURNED AT 4:27 P.M.)

PROCEEDINGS CONCLUDED

Certificate of Transcript

We, the undersigned, hereby certify that the foregoing pages 1 to 239 are a complete and accurate transcript of the proceedings taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Calgary, Province of Alberta, on June 24, 2020.

"Donna Gerbrandt"

Donna Gerbrandt, CSR(A)

Official Court Reporter

- I N D E X -

VOLUME 1

UNDERTAKINGS GIVEN

UNDERTAKING - FOR EPCOR TO ADVISE HOW MUCH OF THE $76 MILLION WAS SPENT ON BACK-END SYSTEMS VERSUS THE METER INSTALLATION COSTS 158