MAINE PUBLIC UTILITIES COMMISSION
AUGUSTA, MAINE

IN RE:)
) Docket No. 2017-232
CENTRAL MAINE POWER COMPANY) June 14, 2018
)

Request for approval of CPCN for the New England Clean Energy Connect Construction of 1,200 MW HVDC Transmission Line from Québec-Maine Border to Lewiston (NECEC)

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CONFERENCE COMMENCED

(June 14, 2018, approximately 9:30 a.m.)

MR. SIMPSON: Good morning, everyone. This is the first in a series of four technical conferences in docket number 2017-00232 which is Central Maine Power Company's request for approval of a certificate of public convenience and necessity for the New England Clean Energy Connect project. Notice of today's conference was provided by procedural order issued on May 25th with additional details included in a procedural order that the Examiners issued yesterday when we scheduled an additional day of conference to accommodate the amount of questions that are anticipated. The other conferences are scheduled for June 19, 20, and 28.

We were having some technical difficulties at the outset, and we still are. Just to explain, we have a recording system which is working. What we are having problems with is a system that allows the hearing reporter to take additional notes. So we're not going to lose anything. We just might not get as clear a transcript as we otherwise would. The fix to the technical part of the problem will happen as soon as possible, and we may need to take a quick break to allow that to kick in. But I wanted to get started so that we didn't burn any more time.

I wanted to begin today with witnesses from the LEI team. I also want to confirm that we are going to begin with

questions relating to gas issues. If we can get through the LEI team today, we will, and that would be great. If we don't, the other members of the team can be made available by phone on the 19th, but Marie can't make it on the 19th. So if you've got questions relating to gas issues, please ask them today.

I think the next thing I want to do is just take appearances and ask everybody to identify themselves. We'll start with the people in the room, and then we'll go to the people who are on the telebridge. My name is Chris Simpson. I'm one of the Hearing Examiners in this case. I'm going to go to Faith, and then we'll go clockwise, including the LEI folks, let's do it that way, and then back down the bench, and then we'll go to the back row. Faith, go ahead.

MS. HUNTINGTON: Faith Huntington of the PUC staff.

MR. BERGERON: Denis Bergeron, PUC staff.

MR. TANNENBAUM: Mitch Tannenbaum, PUC staff.

MS. COOK: Chris Cook, PUC staff.

MR. DAVIS: Randy Davis, PUC Commissioner.

MR. BRYANT: Eric Bryant with the Maine Public Advocate.

MS. WYMAN: I'm Liz Wyman with the OPA.

MR. HOBBINS: Barry Hobbins, Public Advocate.

MS. GREEN: Emily Green, Conservation Law Foundation.

MR. TURNER: Phelps Turner, Conservation Law Foundation.

MR. LANDRY: Andrew Landry from Preti Flaherty for the Industrial Energy Consumer Group.

MS. KELLY: Dot Kelly, Phippsburg.

MS. PORTO: Barbara Porto from London Economics International.

MS. FAGAN: Marie Fagan, London Economics.

MS. FRAYER: Julia Frayer with London Economics.

MS. DUAN: Jinglin Duan with London Economics.

MR. DES ROSIERS: Jared des Rosiers from Pierce Atwood on behalf of Central Maine Power.

MR. PEACO: Dan Peaco from Daymark Energy Advisors on behalf of Central Maine Power.

MR. BOWER: Jeff Bower with Daymark Energy Advisors on behalf of Central Maine Power.

MR. SMITH: Doug Smith from Daymark Energy Advisors also on behalf of Central Maine Power.

MS. TRACY: Sarah Tracy with Pierce Atwood on behalf of Central Maine Power.

MR. SIMPSON: Let's start over here, please.

MR. PLANTE: Ben Plante, Drummond Woodsum.

MS. OLFENE: Amy Olfene, Drummond Woodsum on behalf of NextEra.

MR. MURPHY: Brian Murphy with NextEra Energy Resources.

MR. WHITLEY: Steven Whitley on behalf of NextEra.

MR. RUSSO: Chris Russo with Charles River Associates on behalf of NextEra.

MR. SHOPE: John Shope, Foley Hoag in Boston on behalf of the generator interveners Calpine Corporation, Vistra Energy Corporation, and Bucksport Generation, LLC.

MS. BODELL: Tanya Bodell, Energyzt with the generator interveners.

MR. FLUMERFELT: John Flumerfelt, Calpine Corporation.

MR. WALLACE: Ryan Wallace, University of Southern Maine on behalf of Central Maine Power.

MS. ELY: Sue Ely, Natural Resources Council of Maine.

MS. MONROE: Mabel Monroe, PUC staff.

MR. BRYANT: And Chris, let me add, sitting behind me is our summer intern Cameron Goodwin.

MR. SIMPSON: Welcome, Cameron. If you want to say something, come up to the microphone, okay?

MR. GOODWIN: Pardon?

MR. SIMPSON: Yeah, that was a feeble attempt at a joke. Okay, that takes care of everybody in the room. Let's go to the people on the phone. Eva, would you start? Please identify yourself?

MS. WANG: Sure. Eva Wang, London Economics.

MR. SIMPSON: Thank you. Krystal?

MS. WILLIAMS: (Indiscernible).

MR. SIMPSON: Thank you. Is there anyone else on the telebridge? Okay, great. Thank you. Toby, do you have everybody (indiscernible)? All right. So what I want to do, we'll start out with the public information. We'll start with the LEI witnesses. Again, we'll start with gas issues. We'll continue in that mode until probably mid-afternoon, at which time we're going to go to NextEra witness Steven Whitley. We'll do public questions for him, and then we'll go into the confidential in camera session. And I'll explain that more at the time. Are there any questions?

All right, let's go ahead and begin. What I want to do is I want to start with CMP and invite you to ask questions of Marie. And then we'll go to the Public Advocate, and we'll just go around the table. I know somebody, in their pre-conference memo, suggested an order of witnesses that would be triggered by the date of intervention and that makes some sense. But I think for simplicity it makes sense to do it where we're seated. That way it's easy to follow who's next and you can prepare based on that. So let's start with CMP.

MS. TRACY: We will be questioning today -- I will be asking some questions and Daymark will be asking some questions. The majority of Daymark's questions will be in confidential session. We have a couple of public questions that we are not sure whether they are directed towards Ms.

Fagan or not. So we'll ask them and then, if it's not, you can maybe answer them because there are not that many. And then we'll defer. The rest of our questions are not for the gas team. It's for the remainder of the LEI team.

MS. FRAYER: If I can interject quickly, I just wanted to -- maybe it would help to introduce who's responsible for what piece.

MS. TRACY: That would be great.

MS. FRAYER: That -- so good morning, everyone. My name is Julia Frayer. I'm joined here today with Marie Fagan and Barbara Porto who supported this project with research and analysis related to natural gas prices. I'm also joined to the left by Jinglin Duan who supported the analysis with respect to the macroeconomic impacts. So on these topics, you might -- you may address a question to me, but I may also ask one of the other witnesses to jump in. Similarly, we are joined by our colleague Eva Wang who works out of our Taiwan office, and she will support on questions related to the simulation modeling of electricity market impacts as needed. So just to give you a little bit of a lay of the land, if you will.

MS. TRACY: All right. It may be that our first couple of questions are for Ms. Wang, but we're going to ask it anyway and --

MS. FRAYER: I'd like to -- yeah, please go ahead. And I just wanted you to be aware of the handing over of the

baton.

MS. TRACY: That sounds good.

MS. FRAYER: Do we also (indiscernible)?

MR. SIMPSON: I think I'm reading your mind, and do you want to go through the errata sheet to start out with?

MS. FRAYER: Would it be helpful on the record? I think that might be useful since we handed it out.

MR. SIMPSON: Just so that we're all on the same page literally, let's do that. And then we'll turn to the questions.

MS. FRAYER: Okay. So in the course of preparing responses to the discovery, the data requests, we identified five typographical errors in the report. And we've handed out 12 pages that we hope you could just slide into your binders for the public version of the report with highlighted in green the changes we made for those typographical errors. We discovered one of those pages, page 13, needs to be replaced. We'll do that in short order. I think this will also be uploaded hopefully to the electronic system shortly so others can have copies of those pages.

To just give you a gist of it, these are all basically typographical errors that have no change -- no implications for the conclusions we're making, no change in the overall analysis regarding the projected impacts of NECEC on the wholesale electricity markets and the (indiscernible) Maine

and New England region. The changes, and I'm going to go a little bit out of order, but on the first few pages, page 12, page 13, page 16 are related, and there are some other later pages as well, to a typographical input error in one of the REMI input files. As you see if you compare the original report pages to these changes, you'll see that the numbers have changed in some of the figures and the text, but we're talking about a change in operational period benefits of about five percent in Maine. So immaterial in terms of the directional aspects of our conclusion on the macroeconomic benefits, but we wanted everyone to have the corrected numbers.

On page 25 there was a reference to FC12 which should actually be a reference to FC14. So a typographical error.

On page 34 there's a reference to number of jobs. It, I believe, used to say 38 jobs. It should be actually 37. Again, a typographical error in trying to round the number.

Then there was a change on page 63 where the figure originally said 550 megawatts. The correct figure is 350 megawatts. Again, a typographical number error. There's no changes to any of the modeling inputs or conclusions.

And finally, on page 82 but also page -- some of the prior pages had some changes, again all related to the original changes we've highlighted. But page 82 there's a bar chart that hadn't scaled correctly for some years, and so that has been replaced as well.

All of these corrections have also been done in the relevant DR responses. So the DR responses that have been uploaded I believe earlier this week had the complete and most up-to-date set of information.

MS. TRACY: Thank you. All right, so we will start with Doug Smith from Daymark who has some questions in the realm of electricity benefits related to wholesale versus retail conversion.

MR. SMITH: Good morning.

MS. FRAYER: Good morning.

MR. SMITH: Hopefully this will be real quick and painless. A couple of questions, and I'll be referring to Figure 1 on I believe it's page 11 of your report and also to DR CMP 011-020. So as we're all gathering that, I guess just to be -- to make sure we're all clear and talking about the same thing, the calculations represented on Figure 1 and the adjustment from wholesale to retail is to reflect the fact that the wholesale benefits were calculated on the basis of the entirety of the load in New England and in recognition of the fact that some portion of that is hedged. There's contracts that leave that portion of load not open to short-term wholesale impacts. There was an adjustment made to reach retail benefits. Is that --

MS. FRAYER: Your understanding is correct.

MR. SMITH: Okay. And in CMP 11-20 you presented the

data underlying those calculations, the contracts and the length of time, their key components that make up that hedge, that keep the -- that make a difference between wholesale and retail?

MS. FRAYER: That's correct.

MR. SMITH: Okay. And just to be clear, the list of elements on CMP 11-20, that's the entirety of the hedges that London Economics used in making that adjustment?

MS. FRAYER: I believe so.

MR. SMITH: Okay. And finally, just to make sure I'm reading this right, if I look at the first item from CMP 11-020, it says, "clean," clean energy generator. The contract starts in 2011 and goes for 15 years. So would I be correct in reading this that in terms of your analysis which started in 2023, going through, say, 2026 which appears to be the final year of that contract, '11 plus 15 years, for those years, 620 megawatts of capacity and 4,667 gigawatt hours of energy were treated as hedged and, therefore, not part of the retail benefits calculation.

MS. FRAYER: For the specific state where --

MR. SMITH: For the -- correct, for, in this case, Connecticut, for that --

MS. FRAYER: Yeah.

MR. SMITH: So that's how to read this?

MS. FRAYER: Yes, that's correct. So we didn't --

there was a translation step as well where we took the quantity of -- capacity and energy is dealt with differently as you mentioned in your question because some contracts are for capacity only, some contracts are for capacity and energy. There's also some energy-only transactions in the data set. So when we looked at the capacity -- let's start with capacity first, then we'll talk about energy. The methodology is the same. When we looked at the contracts, for each year we would sum up the total quantity of contracts and convert that relative to the peak load for that state to a percentage. And it was really the percentage that then was used to reduce the amount of peak load share for capacity purposes or total energy consumed from wholesale market price impacts or differences caused by the project case or NECEC in that instance.

MR. SMITH: Okay, that's helpful, thank you. So if I was to use made-up numbers, if there was a hundred dollars of wholesale benefit and you calculated a five percent -- that five percent of that load was hedged, you'd take $5 off the hundred and the retail would be 95.

MS. FRAYER: Yes, that sounds like a good numerical example.

MR. SMITH: Okay, thank you. And then just two quick questions, and I think I'm done. In the response 11-20 there's some language about Maine, and I believe that the gist of what you're saying is that, because of how Maine load is treated,

you did not assume a hedge for Maine. Is that a fair summation or am I misunderstanding something about the response?

MS. FRAYER: I think that's a fair interpretation of it. Specifically, I think in CMP 011-020 what we tried to do is explain our understanding of how some of the existing long-term contracts actually are accounted for, allocated, and why. In the context of Maine, there shouldn't be any assumption of a hedge.

MR. SMITH: Okay. So my last question then is for clarification here. If I go back to Figure 1 and I look at the numbers here, I see -- you list wholesale impacts and then you list retail impacts. And as we would expect, the wholesale impacts are higher than the retail representing this percentage shave that you just walked us through. And I see that for New England as would be expected for all these states, but I also see a reduction for Maine. And given that there are no Maine identified contracts in 11-20 and given the language of 11-20, I'm not sure what is causing the reduction in benefits to -- from wholesale to retail for the state of Maine.

MS. FRAYER: We'll have to take it back and get back to you if you don't mind. I'd like to look into the numbers, and I don't have them in front of me right now.

MR. SMITH: That's fine, yeah.

MR. SIMPSON: Do you want to do that as an ODR or come back to it, like, after lunch?

MS. FRAYER: Whatever works.

MS. TRACY: Why don't we do it as an ODR?

MR. SIMPSON: Okay. Could you please restate that, the question?

MR. SMITH: The question is what causes the reduction in benefits from wholesale to retail impacts for the state of Maine in Figure 1 on page 11 of the LEI report. And that's all I have. Thank you.

MS. FRAYER: Thank you.

MR. SIMPSON: For the record, that's -- I'm not sure what set we're in and I'll figure this out later, but that's number one. I think it's five, but I'm not sure. I'll clarify later. All right, let's go to the OPA. Any questions specifically relating to gas for the LEI team?

MR. BRYANT: No.

MR. SIMPSON: Okay. How about CLF?

MS. GREEN: Thank you. CLF has questions for the LEI witnesses but not specifically with regard to gas.

MR. SIMPSON: Okay. How about the IECG?

MR. LANDRY: I'll say I think all my questions relate to gas.

MR. SIMPSON: Okay, great.

MR. LANDRY: We could list some other issues, but I think in going through them and preparing today, that's really what it came down to. And my name's Andrew Landry. I'm an

attorney with Preti Flaherty, and we're here for the Industrial Energy Consumer Group. You had -- I didn't realize this was going to go so quickly. You didn't have a lot, I didn't feel like a lot, in your report discussing your methodology for gas, but looking at page nine of your report and the top of page ten, you state that you used the EIA's annual energy outlook 2018 to develop your natural gas price forecast. Is that correct?

MS. FRAYER: It is one of our inputs.

MR. LANDRY: Oh. What other inputs did you use?

MS. FRAYER: Well, I can start off and Marie can maybe jump in, but essentially we're using for our gas price outlook are what we call our levelized class to pipeline model, and it will require other inputs and information. For example, the cost of building out new pipelines, forward pricing, class key trading hubs, and so forth. Marie, I don't know if you want to jump in and add anything else.

MS. FAGAN: I could add more if you have more specific -- did you want to ask more specific questions?

MR. LANDRY: I do have more specific questions, but that's fine for now. I know you referenced the levelized pipeline model, and I'll ask some questions about that in a few minutes. I just wondered, I didn't go back and pull out the annual energy outlook 2018, but is that just a national price or do they have individual prices for different regions of the

country in their forecast?

MS. FAGAN: The EIA produces regional prices. They don't have a price that is specifically Algonquin city gate. They produce a northeast price.

MR. LANDRY: A northeast. And the northeast would include?

MS. FAGAN: They break out the northeast a couple of different ways, but they have a northeast price that pretty much corresponds to New England because they'll give you New York separately and some other regions separately.

MR. LANDRY: That doesn't include Pennsylvania the, the northeast?

MS. FAGAN: It does -- the New England price does not.

MR. LANDRY: Okay.

MS. FAGAN: But we don't use that price. But just to clarify what EIA does.

MR. LANDRY: What price do you use?

MS. FAGAN: We refer to their Henry hub price outlook.

MR. LANDRY: Okay.

MS. FAGAN: And also a lot of other information that EIA puts out when they release the annual energy outlook. So we don't just take their Henry hub outlook without thinking hard about what went into it and just sort of automatically

drop it into a model. So when the EIA puts out the annual energy outlook, there's a lot of information besides prices. There's information about what they assume for supply from various regions, and we take all those things into consideration before we decide how to use the EIA outlook.

MR. LANDRY: So but the number that you pull, though, as the starting point is the Henry hub price?

MS. FAGAN: Not the price.

MR. LANDRY: Oh.

MS. FAGAN: The -- we start with a near-term outlook for Henry hub that's based on current prices. And for the last couple of annual energy outlooks, we've used EIA's rate of growth of Henry hub prices but not their price level.

MR. LANDRY: And how then do you set an initial price level from -- is it just based -- I know you have this construction model or levelized model that we'll talk about in a minute, but as a starting price, what -- how do you determine what to use as a starting price for, say, the first forecast here?

MS. FAGAN: We use the forward curve, the traded forwards.

MR. LANDRY: Okay. So you look at actual market information on what people are agreeing to pay for future transactions, is that what I'm --

MS. FAGAN: That's right, public price -- publicly-

reported price information.

MR. LANDRY: Now when we're -- a lot of us in the room here were involved for quite a long time in the natural gas pipeline proceeding here at the Public Utilities Commission. And then you had, at that time, done a fairly extensive modeling of I think gas flows in the northeast and maybe the whole country. Did you engage in any of that activity for purposes of developing your forecast here?

MS. FAGAN: So you're referring to the MECRA proceeding, just for folks who don't know, and we used a very detailed pipeline flow model. Part of that proceeding was a deep interest in receipt points and delivery points on a variety of gas pipelines, and that required a very detailed look at flows from, you know, various points to understand the impact of these pipeline proposals. And that was -- we used a model called GPCM. It's an industry standard network, linear programming optimized network model, not appropriate for what we're doing here. It just -- it would be cutting butter with a chainsaw probably.

MR. LANDRY: Okay. I just wanted to understand whether you had used it or not, and I assume --

MS. FAGAN: No, no.

MR. LANDRY: And the -- and maybe the simple -- other than the amount of resource that would be necessary to run it for these purposes, you're just really interested in what the

regional price is, so the New England regional price, is that fair, in this case?

MS. FAGAN: And the -- it's out of the scope of the work that we agreed with the Commission staff. It was out of scope to go into that level of detail with a tool like that.

MR. LANDRY: Okay. Now on page 20 of the report just above Figure 7 -- and I'll give you a second to find that if you want -- you note that you have added a transportation adder for New England using your levelized cost of pipeline model which we just talked about a little bit. How -- can you briefly describe how that model works?

MS. FAGAN: So we have an input to that model which is the outlook for Henry hub gas. That's a North America wide market for gas prices. And there are a number of other, let's call it, hubs, pricing locations, in our levelized cost of pipeline model. There's pricing locations at the Marcellus which is a very important supply region particularly for New England because it's close. And we have Algonquin city gate as a hub, etc. And the levelized cost of pipeline model is a top-down, long-term equilibrium model.

So what does that mean? Models have to have something that drives the solution. What drives the solution in this model is that ultimately, over time, as long as the market can work, the price between one hub and another should only be the cost of transportation from one hub to another. So

that's the rule the model uses to find a solution. So when we look at a Henry hub price and some important Marcellus prices, they're a certain distance from Algonquin. We know in the real world that it's hard to predict when pipelines will get completed, if at all, but the model shows us when you've got a big enough differential in gas prices to incentivize building a pipeline. And that's how that works.

MR. LANDRY: So the modeling that you've done will -- assumes that those pipelines will get built but some during -- probably incrementally over time.

MS. FAGAN: It indicates where a pipeline ought to get built. It indicates the time that it ought to happen. And then we look at it and use our judgment and say, yes, okay, there are some pipelines underway, they'll get delayed but, yes, it looks like this could get completed by 2020, 2021, etc. So we add a layer of judgment on it because we know what the real world is like. It's not easy to get pipeline projects done.

MR. LANDRY: So you haven't -- well, it sounds like you do use some individual judgment, but you haven't reflected specifically, for instance, political or regulatory barriers to getting new pipelines constructed into New England from outside the region?

MS. FAGAN: So if you're asking is that quantified in the model?

MR. LANDRY: Right.

MS. FAGAN: No. And even in a detailed model like GPCM, when you're setting it up, you kind of have to tell that model, yes, this pipeline's going to be available on date X or, no, it isn't. It'll give you a solution, but any model requires that you make some expert judgment so that you get, you know, sensible outcomes.

MR. LANDRY: So in doing your -- preparing your forecast here, did you make assumptions about that there would be new pipeline constructed within some time period?

MS. FAGAN: So what we're assuming is that Atlantic Bridge will get completed. It's -- some of it's already done. We've seen some of the impact on Algonquin prices already compared to a few years ago, but there's pieces that are still working their way through the regulatory process. So we do assume that gets done -- it could get done this year, next year. In the model I think we have 2021. But in any case, it's before the outlook period that's analyzed for the benefits analysis.

MR. LANDRY: Well, any of the larger projects that were the subject of this -- in a separate proceeding here --

MS. FAGAN: Why -- are you asking if we assumed that, say, NED will get built in this model?

MR. LANDRY: Right.

MS. FAGAN: We are not assuming that, no.

MR. LANDRY: Or any other similar project, similar size?

MS. FAGAN: Did we -- oh, like Northeast Energy Direct -- or the other one --

MR. LANDRY: Right.

MS. FAGAN: -- the Algonquin one? No.

MR. LANDRY: No. So those are assumed not to be in service, is that --

MS. FAGAN: Not explicitly, and we don't see the empirical evidence for it either and it's not in the model.

MR. LANDRY: Okay. Hold on just -- sorry, do it on the fly here. Trying to balance what we talked about a minute ago where you said that the model will assume that pipelines will get built when it's economic to do so, you are not assuming a specific project like either of the ones that were considered here. So I'm just wondering does the model then pick up in some future year, 2025 or something, that a line like that would be built without having a specific project in mind?

MS. FAGAN: It does not.

MR. LANDRY: Okay. I think in your footnote on -- footnote eight on page ten you state your assumptions do not assume any sudden spikes in demand of natural gas prices due to weather conditions essentially. Is that true of the levelized -- your levelized cost of pipeline model, is that true that

particular layer of your forecasting doesn't have any adjustment for that either?

MS. FAGAN: Give me a minute to read the whole sentence.

MR. LANDRY: Okay, sure.

MS. FAGAN: That's right, it's a normal weather forecast.

MR. LANDRY: Okay.

MS. FRAYER: And if I can add, it's a normal weather forecast across all other variables as well. That's intentionally made to be consistent.

MR. LANDRY: Thank you. I don't have too much more, but -- I guess I'd turn to pages 39 and 40 where you do some comparison to the Daymark modeling. And if I read this correctly, and it may be just easier to look at Figure 24 on page 40, you've tried to quantify differences between the Daymark forecast and your own at least with respect to -- well, some of them were with respect to gas at least. And when you say -- there's a second bar, and I know you describe it a little bit on the page before, but the higher delivered natural gas prices which are -- Daymark's analysis used higher numbers. Is there any difference in there other than the fact that they used the earlier EIA forecast and you used a more recent EIA forecast?

MS. FAGAN: Yes, that -- there are other differences

beside the EIA forecast difference.

MR. LANDRY: Yeah. Without getting into too much detail, could you just summarize what some of the other different -- the most -- the major factors are in that number?

MS. FAGAN: It depends what month of the year you're looking at.

MR. LANDRY: Okay.

MS. FAGAN: One of the factors that actually doesn't vary across the months is what they called a regional adder. Plants in New England were assumed to pay more for gas because of where they were. That impacts their outlook across the year. And then looking at the summer months, there was a peaking unit adder for gas prices, and that probably impacted in the winter months too but summer is where you see a lot of the impact of running the peakers. It was that peaking unit adder.

MR. LANDRY: Okay. Do you believe that there is a difference in the cost of gas delivered in northern New England versus southern New England? Have you analyzed historically whether that's been an issue?

MS. FAGAN: I don't have any numbers offhand, off the top of my head. The numbers that Daymark used, they didn't use delivered gas prices. They used a proxy based on firm transportation cost on Maritimes & Northeast shaped by the monthly transportation cost increment on PNGTS. It's not clear

any of those units are actually buying FT, firm transportation. So Daymark didn't use an observed delivered price either.

MR. LANDRY: Thank you. And then right next to that one there's a reference to a regional adder that Daymark used that I assume you didn't use, and I guess I'd ask if you would just explain what's in that number as you understand it?

MS. FAGAN: Just to repeat, there's a piece that has to do with the cost of firm transportation on Maritimes & Northeast, and there's a piece that has to do with the shape of the monthly price of FT on PNGTS.

MR. LANDRY: Okay. I thank you for clarifying. I guess I was asking previously about the higher delivered natural gas price bar on Figure 24, and I see that you were referring to the regional adder bar. And that's fine. That's clarified.

MS. FAGAN: Okay.

MS. FRAYER: If I can jump in --

MS. FAGAN: I think I might be misunderstanding, yeah.

MS. FRAYER: Yeah.

MR. LANDRY: Sure.

MS. FRAYER: So I think Marie's response in the last few minutes was focusing, if I can use the color coding of the bars, she was speaking to the yellow bar and the blue bar which, I don't know if you have the printout in color, but the

yellow bar is the peaker adder, the blue bar the regional adder which is reflecting the differentiation year round between northern New England and rest of New England. I think your question might have been what else is different other than the vintages of the EIA energy outlook for the gray bar, the one that's higher delivered.

MR. LANDRY: Right.

MS. FRAYER: Is that correct? We were trying to figure out if that's --

MR. LANDRY: Yes, that was my earlier question, yes.

MS. FRAYER: Okay. If I can take a crack and then Marie can jump in.

MS. FAGAN: Go ahead.

MS. FRAYER: So on the prior page, page 39, we talk about how we developed this gray bar, and we said, well, what we did is we took the index price from AEO 2016 which is what we understand Daymark did. It's a very specific index price, though. It's not the same thing that we did where we started with a Henry hub outlook from AEO and built up using our LCOP model to an Algonquin city gate. Our understanding is Daymark used a specific regional price. So maybe to answer your question very shortly, the gray bar, it's not just a difference of vintage of AEO 2016 versus AEO 2017. It's also actually a difference of how you use the AEO, what aspects of the AEO you incorporate into your delivered gas price forecast to New

England.

MS. FAGAN: That's right. I apologize for misunderstanding.

MR. LANDRY: No, that's fine. Thank you very much. I guess the last question I'd come back to really relates to comparing what you did for analysis here versus what you did back, again, in the natural gas pipeline proceeding that you participated in at the Maine PUC. And I know we talked about the fact that you did this regional pipeline modeling that we didn't engage in here, but I just wonder were there any other important methodological differences between the forecast you developed here -- I know those inputs have changed obviously, but whether any of your methodology changed substantially from that proceeding to this proceeding.

MS. FAGAN: Using the GPCM model, we did not use the forward curve for the first two years of the outlook. We used the model for the whole thing. The way we use our levelized cost of pipeline model, LCOP, we start with the first two years of the forward curve for Algonquin. And that's the difference besides using LCOP versus GPCM.

MR. LANDRY: Okay. And is that -- it feels like the changes are significant in the first two years, but in the out years it's more similar in terms of the approach. Is that --

MS. FAGAN: Well, in theory, that's where the difference is. But if you look -- and I went back and looked

at our outlook in the pipeline proceedings. We had two outlooks; we had a high case and a low case. And now, of course, we're just using a baseline. But the front end of our outlooks is -- it's very close actually. The GPCM model did a good job of getting the near-term forecast right.

MR. LANDRY: Thank you. That's all I have.

MR. SIMPSON: Thank you. Does NRCM have any questions for -- relating to gas issues?

MS. ELY: We have questions but not about natural gas.

MR. SIMPSON: Great. How about NextEra?

MS. OLFENE: We don't have any gas questions today.

MR. SIMPSON: Okay. And how about for the generator interveners?

MR. SHOPE: We have a couple -- oh, excuse me. We have a couple questions about the impact of the gas assumptions on the overall benefits. I don't know whether that's --

MR. SIMPSON: No, now's a good time for those. Go ahead.

MR. SHOPE: Oh, okay, sure. And these are, frankly, just very basic questions. Obviously to some degree you're -- what you're doing is just making a prediction based on your best professional judgment. Is that fair?

MS. FAGAN: It's a combination of professional

judgment and some quantitative tools to test -- just sort of to keep you honest. It's not just what you want to happen or what your gut tells you will happen. You work it through the model. When you model and you do quantitative analysis, usually you learn something that you can't just -- you know, that you can't just dream up.

MR. SHOPE: Sure. But obviously you don't know to a certainty how all of these variables are going to play out over the next 15 years.

MS. FAGAN: I would be rich if I knew that.

MR. SHOPE: So just some basics. So in other words, putting aside whether it's probable or not, it's possible, for example, that, you know, if the economy were to turn down and that reduced demand for natural gas, that the gas prices might turn out to be lower than what's forecast in your model.

MS. FAGAN: Do you mean Henry hub or do you mean Algonquin?

MR. SHOPE: Well, I'm focused on the gas prices that would be delivered to the New England plants.

MS. FAGAN: It's something that you'd want to work through all the details, but -- so you're presupposing lower demand for natural gas. In United States?

MR. SHOPE: Yes.

MS. FAGAN: Or globally or --

MR. SHOPE: Well, let's focus on the United States.

MS. FAGAN: Okay, so if you have lower demand for natural gas in the United States, you might have lower gas prices in the United States or you might not because a lot of the growth in gas supply in the United States is in the Texas area and all this other gas trying to get there for export, for LNG exports, for huge pipelines expansions. So it could be offset by global demand, but gas market didn't used to be global the way it is now.

MR. SHOPE: Sure.

MS. FAGAN: It's just there's a lot of variables. There could be a world with lower gas prices. There could be a world with higher gas prices.

MR. SHOPE: And then obviously there are many, many different things that would determine that. Fair to say?

MS. FAGAN: Well, they would boil down to supply or demand or debottlenecking transportations. I mean, within those three categories there's a lot of things, but you can put them in those buckets to think about them.

MR. SHOPE: Sure. And just -- but just to be clear, well, presumably you've used your best judgment to try to make the forecast of what the gas prices will be. If the gas prices turned out to be lower than what you've forecasted, that would reduce the benefits of the proposed transmission line. Is that a fair statement?

MS. FAGAN: I think there's a lot -- I mean, on the

gas side. Perhaps on the power side there would be more generation. I don't -- I think there's a lot of bits and pieces of that. I don't know if I could jump to that conclusion. Julia, do you want to --

MS. FRAYER: I would say that holding all else constant, if, for some reason, gas price levels -- delivered gas prices to Algonquin declined, you would see some -- I call it kind of inter-related effect but some reduction in just the energy market benefit piece. But it's not going to be anywhere one for one because our energy market benefits are based on differences in energy prices, not absolute energy prices. So if you were asking a hypothetical, lower gas prices, does it mean lower energy prices? Yes. Does it mean a one-for-one lower energy market benefit? No, because we're looking really at the differences. And, frankly, if you go back to Figure 1 in our report and look at the composition of the total electricity market benefits, the majority of the benefits are capacity market benefits which, if gas prices actually do decline significantly, we would expect capacity price levels over time to rise significantly. And then this project would actually have bigger capacity market benefits. So there's that inter-relationship too over time. So you would need to study it empirically to really know the effect.

MR. SHOPE: And not to get off topic, but that capacity market benefit would assume that it would be the --

that the project would participate in the forward capacity auction -- the standard auction rather than the substitution auction.

MS. FRAYER: Yes, that is correct that it would -- well, it's not even assumed participation. That it would clear in the primary auction which, frankly, if capacity prices are higher, holding all else constant, increases the probability of the project clearing in that primary auction as well.

MR. SHOPE: We have many other questions for LEI but not specifically on gas.

MR. SIMPSON: Thank you. So that takes care of the public questions for -- oh, I'm sorry, Dot, do you have questions? Come on up. Dot, now you did not file a pre-conference memo which is required for asking questions of the witnesses. How much do you have for the witnesses? What's your time estimate?

MS. KELLY: I actually have no questions at this point and wanted to clarify that I did not plan to ask any initializing questions of any of the witnesses but would like to confirm that, as issues come up, I'd try to encourage transparency and would like to know whether I'm going to be able to ask some clarifying questions when I think there's been unclear responses.

MR. SIMPSON: You will be given an opportunity to do that. Just let me know if you have any, and we'll give you the

chance to do that then.

MS. KELLY: Thank you.

MR. SIMPSON: You're welcome. Okay, so are there any other non-confidential questions relating to gas issues? Okay, in the pre-conference memos that were filed by CLF, CMP, and the generator interveners you indicated that you did have some confidential questions for LEI. Do any of those confidential questions relate to gas issues?

MS. TRACY: No.

MR. SIMPSON: This is just for my own planning purposes.

MS. TRACY: Not for CMP.

MR. SIMPSON: Okay.

MR. TURNER: Not for CLF.

MR. SIMPSON: How about the generator interveners?

MR. SHOPE: None.

MR. SIMPSON: Okay, great, thank you. That's helpful. So now let's switch gears and expand the questions to include everything else. And I'll go back to CMP.

MS. TRACY: Good morning. I'd like to direct your attention to CMP 11-01. This relates to the resume for Ms. Frayer which is -- and I'm referring to page 11 of 33. And it's the first full bullet on that page. In your resume you indicate that you performed a ten-year energy market price outlook for New England wholesale market and forecast the

impact of a proposed project on New England market prices. And you indicate that this project was a transmission line from Quebec to Vermont. Was this the TDI New England Clean Power Link Project?

MS. FRAYER: Do you mind just telling me the page number again? Because it'll give me --

MS. TRACY: Sure. It's page 11 of 33.

MS. FRAYER: There's a -- so the way that my CV was organized for this filing is it was provided in public format. I have many, many projects that involve confidential clients whose names the client hasn't given me permission to disclose for a variety of reasons in my public CV. So I cannot confirm right now who that project developer was because apparently they haven't given me permission to do so from reading my own CV. So --

MS. TRACY: If I were to ask the question in confidential session, would you be able to respond?

MS. FRAYER: I'd have to go and check our confidential project database to confirm that that's the overlap, but we can try it that way. Although I don't know -- I'd have to probably check with my lawyers too whether the non-disclosure agreements that we have for our work here covers NDAs that our company signs with clients. So I'm not trying to be obtrusive. I just know that there are sometimes issues. Maybe if you can ask your question without knowing the name of

the party, I can answer a lot -- all the questions. I just can't disclose the client. That's the issue.

MS. TRACY: Well, is the transmission line that is referenced in this paragraph the TDI -- the transmission line that you analyzed, regardless of the client for whom you did it, was that the --

MS. FRAYER: Still can't answer that. But I can tell you the transmission line was between Quebec and Vermont as it's written here. I can tell you the timeframe of operations of the line and so forth.

MS. TRACY: Can you tell me when you prepared your report or your analysis?

MS. FRAYER: This would have been probably a few years back. I can't give you the exact timeframe.

MS. TRACY: All right.

MS. FRAYER: I would need to look that up. It's not covered in the format of this CV.

MS. TRACY: Okay. Can you tell me whether the -- what the product was of that analysis? Was it -- did you prepare a report?

MS. FRAYER: There was probably a client-driven deliverable. I don't know the format, if it would have been a PowerPoint or a written report, but there would have been a physical deliverable provided to the client for their consumption.

MS. TRACY: Do you remember whether you conducted -- or the deliverable included an actual model like, for example, the models that you've produced in this proceeding?

MS. FRAYER: Well, we haven't produced any models.

MS. TRACY: You've produced the results of models.

MS. FRAYER: Yes, of course. It would have been the results of our modeling, the analysis. So it would have covered questions that they would have asked at that time around their project.

MS. TRACY: And are you able to produce a copy of the deliverable?

MS. FRAYER: No. Sorry. I have to not shake my head; I have to say something. I can't because those are subject to very stringent non-disclosure agreements.

MS. TRACY: All right. Is this -- can you turn to page 26 of your resume? So on page 26 you have a similar description, prepared a -- I'm looking at the sixth bullet down, and you say you prepared a ten-year energy market price outlook of the wholesale power market and forecast of the impact of the proposed project on New England market prices. Is this the same project that is discussed on page 11?

MS. FRAYER: I don't believe so. But again, in kind of similar fashion, I can't disclose the name of the project or client.

MS. TRACY: Okay.

MS. FRAYER: There are, of course, analyses similar to this that we have prepared that are in the public domain, and I think we provided references to some of that.

MS. TRACY: Are you referring to Appendix 2 to this response?

MS. FRAYER: I don't know if it's Appendix 2, but we gave, like, links to where we've provided analyses that have been filed, let's say, in public regulatory proceedings. So --

MS. TRACY: Yeah, okay, Attachment 2 is (indiscernible). Okay. Page 13 of your resume. In the first full bullet, conducted New England modeling on wholesale electricity market dynamics. Is your answer the same when I ask you can you describe who you prepared it for and when?

MS. FRAYER: I believe that this may have been released publicly.

MS. TRACY: Okay.

MS. FRAYER: But my colleagues have blinded the name of the client so I would need to check because it does say that it should have been released late last year. I could get back to you after lunch. If it has been publicly released, we'd be happy to give you the analysis. This particular project was not related specifically to transmission investment.

MS. TRACY: Could you give a description as to why you were looking at the wholesale energy market dynamics for purposes of this project?

MS. FRAYER: I can tell you that the client was interested in this work as part of an initiative where they were looking at policy questions with respect to wholesale market dynamics and state-level policy initiatives of various sorts and wanted to understand how state policies may interact with wholesale markets.

MS. TRACY: Thank you. Page 20 of your resume. I'm referring to the third bullet down where you conducted a comprehensive cost/benefit analysis of a proposed transmission project in New England using simulation-based analysis of the ISO New England wholesale power markets. Can you indicate for whom you conducted this analysis and whether it was -- and which project that was for?

MS. FRAYER: I'm just looking. Sorry, can you tell me the page reference? I must have lost it.

MS. TRACY: Sure.

MS. FRAYER: It was page --

MS. TRACY: It's page 20 of 33, and it's the third bullet down. And it starts "Conducted a comprehensive cost/benefit analysis of a proposed transmission project in New England."

MS. FRAYER: I'm trying to refresh my memory based on where this bullet is, of which one it is. So I can't provide you -- I cannot provide you with a name, again, of the specific project in this instance or the client. This analysis was not

-- to my knowledge, was not made public.

MS. TRACY: Is there anything that you can tell me about this analysis in terms of why it was conducted or whether it was similar to the transmission project proposed here?

MS. FRAYER: This project was conducted to analyze transmission investment proposals that were being undertaken by an entity in the market, and they wanted that information for their due diligence. I can tell you that it's not locationally and technically like the HVDC project we're currently analyzing for NECEC. Our region has seen lots of various transmission proposals over time.

MS. TRACY: And do you remember approximately when you conducted this analysis? Are we talking last year or so or --

MS. FRAYER: No, longer. This is going back longer.

MS. TRACY: Please turn to page 31 of your resume. In the middle of the page under development and strategy, you assisted in strategizing the upcoming clean energy -- for the upcoming clean energy RFP. Is this the RFP that was issued by Massachusetts in 2016?

MS. FRAYER: This was the RFP that involved three states: Massachusetts, Rhode Island, and Connecticut.

MS. TRACY: And in the -- this analysis were you analyzing transmission lines or what were you analyzing, what projects?

MS. FRAYER: The potential suite of projects that could qualify to be offered into that RFP. So it was not limited to transmission projects in that RFP.

MS. TRACY: On page 32 at the top of the page, you have a reference for your implications of energy infrastructure investment on local economies in New England. Do you have a copy of that presentation that you could provide?

MS. FRAYER: We can definitely check. It's for what conference?

MS. TRACY: It's on the top of page 32, and it was for the REMI E3 conference in 2015 which took place in Amherst, Massachusetts.

MS. FRAYER: Yes, we can definitely provide a copy of that presentation.

MS. TRACY: Okay. I'd like to make that an ODR.

MR. SIMPSON: Sorry, ODR 2. I'll get the series number at break and clarify that on the record.

MS. TRACY: Okay. So that concludes my questioning of your resume, Ms. Frayer. I think I would like to follow up with you on the analysis that I first questioned you about which was on page 11 which was the ten-year market price outlook of the 1,000 megawatt DC transmission line between New England and Quebec. So I will hold off doing that right now. What I'll do is in confidential session, I'll come back and see what you can answer at that point, and then maybe I'll issue an

ODR.

MS. FRAYER: Hopefully I'll have time to talk to our legal people over lunch break and check what I can and cannot speak about that project.

MS. TRACY: And one way to deal with it is maybe I just issue the ODR in confidential session and then it gives you an opportunity to track that down.

MS. FRAYER: Thank you.

MS. TRACY: Okay.

MR. SIMPSON: Sarah, while you're looking, I would like to take a break in about five to ten minutes, whenever is a good breaking spot for you. I'm not suggesting now is that time because we started late, but I just wanted to give you a head's up.

MS. TRACY: Okay, thank you. Is Mr. Hakim present today or no?

MS. FRAYER: He's not.

MS. TRACY: Ms. Duan, I'd like to refer to your resume at page two.

MS. WANG: Sure.

MS. TRACY: And on page two of three there's -- the fourth line down.

MS. WANG: Can you give me the page number again?

MS. TRACY: Sure, page two of your resume, and it's the fourth bullet down. And the question for you, if you're

there, is whether -- this is the entry that talks about the macroeconomic impact evaluation for a transmission project in New England. My question is whether -- is what project this was -- this analysis was for, which transmission project?

MS. COOK: Sorry, Sarah, what page are you (indiscernible)?

MS. TRACY: I'm at Ms. Duan's CV, and it's on page two of three and it is the fourth bullet down.

MS. WANG: It's page --

MS. DUAN: Eva, I think --

MS. WANG: -- page two --

MS. DUAN: Eva, I think it's referring to me.

MS. TRACY: Sorry.

MR. SIMPSON: That's what I think too, yeah.

MS. TRACY: Sorry, yeah, I didn't catch that. My bad.

MS. DUAN: Is it part of the Attachment 4, CMP 001-001 -- sorry, 011-001?

MS. TRACY: Yes. It's part of Attachment 1 to that, and page 45, electronic page 45. Thank you.

MS. DUAN: Page 45. Could you repeat your question again?

MS. TRACY: Sure. On that page, the fourth bullet down, there's an entry that states that your -- one of your sample project experiences is the macroeconomic impact

evaluation for a transmission project in New England. My question is what transmission project was this analysis conducted for?

MS. DUAN: For similar reason stated by Ms. Frayer, I cannot release the client name or the project name, no.

MS. TRACY: Can you tell me when it was conducted, approximately?

MS. DUAN: Yeah. Last few years.

MS. TRACY: Can you tell me what the product of the analysis was for the client?

MS. DUAN: The deliverable?

MS. TRACY: The deliverable.

MS. DUAN: It's a report but not published.

MS. TRACY: Near the next page -- well, actually, let me just ask you one more thing. On the page two, the -- for this project that I was just asking you about, can you indicate whether the transmission project was an HVDC transmission project?

MS. DUAN: It is.

MS. TRACY: Turning to the next page, the first bullet indicates that you conducted a social and economic benefits analysis for a proposed transmission project, and in the description it indicates that it is in New England. I -- is it correct to assume that this is different than the analysis that was conducted that you describe on the prior

page?

MS. DUAN: It's a different project.

MS. TRACY: Are you able to identify the project for which this analysis was conducted?

MS. DUAN: We cannot release the name of the client or the name of the project, no.

MS. TRACY: Can you tell me whether it is an HVDC transmission line project?

MS. DUAN: It was.

MS. TRACY: And can you tell me approximately when this analysis was conducted?

MS. DUAN: It's also within the last few years.

MS. TRACY: Again, I may circle back on these two projects that I've questioned you about in confidential session. Thank you. Ms. Wang?

MS. WANG: Yes.

MS. TRACY: Your resume at page two -- which I'm not exactly sure what the electronic page is yet.

MS. COOK: Fifty-two?

MS. TRACY: Fifty-two. Try 52. I haven't verified it. Okay. So on page two, at the bottom you indicate that you conducted an empirical analysis for NESCOE which included evaluation of financial incentives for existing resources to remain in operation versus retire. Do you have a copy of this analysis that you can provide?

MS. WANG: If everything is public, it will be released by the client. So I can refer you to the website which includes our analysis (indiscernible) and they do further analysis. So I can refer you to that website.

MS. TRACY: Okay, so why don't I issue an ODR just to get that into the record? So the --

MS. WANG: Sure.

MS. TRACY: -- ODR is for Ms. Wang on page two of her resume, the project referencing the 2017 analysis for the New England States Committee On Electricity, please provide a copy of this analysis or a link to the analysis and any subsequent related analysis that was conducted by LEI for this project.

MS. FRAYER: Again, we'll provide what's in the public domain.

MS. TRACY: Understood.

MS. FAGAN: Okay.

MR. SIMPSON: That's ODR 3.

MS. TRACY: I'd like to refer you to CMP 11-08. This question asked LEI about -- asking -- asked them for all sensitivities that were run for purposes of developing independent analysis. In the response LEI indicated that it was tasked to run one base case and one project case and that no sensitivities were run. But then the response says that LEI did consider the potential consequences of the project not clearing the primary auction for the forward capacity market

and refers to specific pages in the LEI report. For purposes of clarification, did you run any POOLMod sensitivity analyses for this scenario where the project did not clear the primary auction in the forward capacity market?

MS. FRAYER: No.

MS. TRACY: So is it fair to say that this was a qualitative analysis rather than a quantitative one?

MS. FRAYER: No, I don't think that that's fair. I would say that we ran our full forward capacity market simulation to understand what would happen if it did not clear in the primary auction and, therefore, would clear in the substitution auction.

MS. TRACY: Have you produced that forward capacity market simulation to date in the record of this proceeding?

MS. FRAYER: We've provided all of the results related to all this analysis I believe in this proceeding.

MS. TRACY: I'd like to just have a confirmatory ODR. Could -- and that would be could you please provide the forward capacity market simulation regarding the potential consequences of the project not clearing the primary auction in the forward capacity market or refer us to the appropriate data response where that was produced?

MS. FRAYER: We can definitely fill you in, yeah.

MS. TRACY: Thank you.

MR. SIMPSON: ODR 4.

MS. TRACY: All right, that concludes our public questioning of LEI.

MR. SIMPSON: Great. So this is a good break time. Let's take a break now and come back at ten minutes till.

CONFERENCE RECESSED (June 14, 2018, 10:34 a.m.)

CONFERENCE RESUMED (June 14, 2018, 10:49 a.m.)

MR. SIMPSON: All right, let's go back on the record. It occurred to me about ten minutes into the cross examination that I forgot to sweat this panel in. So what I want to do now is I want to swear the panel in. And Eva, I want to confirm that you're on the telebridge. Are you there?

MS. WANG: I'm here.

MR. SIMPSON: Okay, great, so this is also for you too. Would you stand, please, and raise your right hand. Do you swear or affirm that the testimony that you gave earlier today and are about to give going forward is wholly truthful?

(Panel responds affirmatively)

MR. SIMPSON: Thank you. Please be seated. All right, let's begin with CLF.

MS. GREEN: Thank you. Good morning. I'm Emily Green with Conservation Law Foundation. If you would direct your attention to CLF 002-004 which references page 19 of your report. Now I understand that LEI did not conduct an analysis to estimate NECEC's minimum offer price for the forward capacity market. Is that correct?

MS. FRAYER: Yes.

MS. GREEN: And instead, LEI assessed two different scenarios, one in which NECEC clears the primary auction and one in which it either doesn't clear at all or it clears in the substitution auction.

MS. FRAYER: The second scenario is where it doesn't clear in the primary auction and, therefore, participates in the substitution or secondary auction. And based on our modeling analysis, it will clear in that substitution auction.

MS. GREEN: Did LEI assign a probability to those different scenarios?

MS. FRAYER: No, we did not assign any quantitative probability.

MS. GREEN: And why not?

MS. FRAYER: The distinction between those two scenarios hinges, as we also describe in our report, on what the specific minimum offer price is, the MOPR, for the project. As we haven't done quantitative analysis, we can't go any further with developing a quantitative probability at this time.

MS. GREEN: So LEI would need to conduct a full analysis estimating NECEC's minimum offer price in order to assign a probability to the scenarios?

MS. FRAYER: In order to feel comfortable giving you a numerical probability on the witness stand or in an official

report. We do talk about, though, the relatives. It is very likely if the MOPR is relatively low, that it will clear in the primary auction. If the MOPR ends up being relatively high -- and relative is really in relation to the capacity price forecast in the primary auction -- then we know that it is more likely that it will then move to participate in the substitution auction and clear in that substitution auction.

MS. GREEN: Certain word choices in the report do suggest that LEI may lean one way or the other. And, for instance, the introductory statement at page 18 that LEI estimates the NECEC would provide Maine $346,000 million in wholesale electricity market benefits suggests that LEI leans toward assuming that NECEC would clear in the primary forward capacity market auction. Is that a true -- it's right there, the very first sentence on page 18. So I guess in short, does LEI lean one way or the other towards -- in terms of the probability of those two scenarios?

MS. FRAYER: Chris, we're in confidential session, is that correct? Sorry. Or no --

MR. SIMPSON: We're not. This is public session, and we'll stay public session until late afternoon.

MS. FRAYER: Thank you. Sorry.

MR. SIMPSON: Yeah, thank you for checking.

MS. FRAYER: Okay. So I would say that we can't assign a quantitative probability, but I do think that we were

leaning towards it more likely clearing the primary auction. And, again, it's because of the relative prices, capacity prices, we are seeing through the simulations. We think that it's plausible to see a MOPR that would be sufficiently below that capacity price for a project like this based on our professional judgment. The reason I asked about confidential session, I was about to name the price, but that is marked confidential so we can't discuss the specific number, the price, for the first auction right now. But that's part of our judgment in terms of, I guess, leaning towards that.

MS. GREEN: Okay, thank you. Maybe I'll ask some follow up during the confidential session. For now, if you would move on to page 20 of the report, please. Again, in the very first sentence here, I understand that LEI assumed, for the purposes of isolating and estimating the benefits of the NECEC project, no addition of a large elective transmission upgrade in the base case scenario. Is that correct?

MS. FRAYER: Yes, as stated in that first complete sentence on page 20.

MS. GREEN: So setting aside the need to evaluate NECEC in isolation, is it realistic to assume that, in the absence of NECEC, that there would be no additional large elective transmission upgrade development?

MS. FRAYER: For the purposes of the analysis that we were doing, which is to estimate the benefits of NECEC, I think

it's appropriate to assume that. If we were asked to do a price forecast in a vacuum without necessarily the engagement in hand of thinking about the estimated impacts of this project on the market, we could develop a baseline forecast that has a number of different possibilities in there, including, for example, a generic -- including a generic transmission project without saying it's NECEC or saying it's something else. But I think for the purposes of this analysis, and that's what we were trying to communicate, it's actually important to be able to think of the world without this project. And if you decided to hypothesize that an identically similar project's going to come in its place, I think you're basically invalidating the concept of doing the incremental analysis in the first place.

MS. GREEN: Like, I understand what you're saying about why you did it this way. But what I'm nevertheless trying to get at is whether it would be realistic to assume that there would be something else in the absence of NECEC in a base case scenario developed outside of this context.

MS. FRAYER: What is that something else?

MS. GREEN: Well, I don't have a particular in mind. My question is because your analysis does not include the addition of a different large elective transmission upgrade for the purposes of evaluating this particular project, if we were not evaluating this particular project, would it be realistic to assume another transmission project like this?

MS. FRAYER: One -- if one were doing an analysis that involved, for the sake of just analysis forecasting, different future conditions in New England, I think it would be reasonable to assume one of the scenarios might say, oh, maybe it's a new transmission line, maybe it's more offshore wind, maybe it's -- depending, I guess, on the political and regulatory atmosphere, more energy efficiency projects being driven by state policies. So there's a lot of, I guess, alternative assumptions one could build in, depending on the specific objectives of the analysis and how -- in what context it's going to be used.

MS. GREEN: So if all things were otherwise the same, if you evaluated a base case that did include the addition of an alternative electric transmission upgrade, what effect would you expect that to have on your price forecasts?

MS. FRAYER: So I will first say that I don't agree with the hypothetical. I wouldn't do that type of analysis. If my intent is to evaluate what this project could mean, I wouldn't want to essentially subvert the analysis by putting the project in both the base case and the project case because then they would negate each other. There would be no difference between the base case and the project case. So I wouldn't take on that hypothetical for the purposes of this evaluation. If, however, there were known plans by -- and I'm giving you a hypothetical because I don't think this actually

exists in the world as we know it today -- there were known plans by the authorities running the Massachusetts RFP which awarded the contract to NECEC that, but for NECEC, they would do X, Y, and Z, I would consider what X, Y, and Z would have been in the base case. And then it's a question of, well, what does X, Y, Z do to wholesale energy prices, to wholesale capacity prices. So you would look at its characteristics, what size is that X, Y, Z project, what is it, size in terms of capability, in terms of energy production or energy flows into the system. Its location. Its potential commercial operating date. We would need its information on investment costs and local spending for installation of that X, Y, Z project. So you would basically kind of go back and think of all the same pieces that we have tried to think of in our current analysis of NECEC.

MS. GREEN: Okay, thank you. If you would turn your attention to page 24. In the second-to-last paragraph there, would you please explain why energy market benefits did not fully dissipate when the new resources added into the base case are assumed not to be inframarginal?

MS. FRAYER: And I'm looking because I think we answered that exact same question in one of our DR responses.

MS. GREEN: Okay. I may have missed it so if you can direct me.

MS. FRAYER: Yeah, let me just take a quick peek

through my summaries. Okay. I think it's in response to GINT-001-001 -- sorry, dash 016.

MS. GREEN: Okay, great, thank you. I'll review that, and if I have follow-up questions, I'll come back to them.

MS. FRAYER: Thank you.

MS. GREEN: I do have other questions on that, and if they're also answered there, we can just save those for later. In LEI's wholesale energy market analysis, how come LEI assumed that the new resources added in the base case would be combustion turbines and not inframarginal generational resources?

MS. FRAYER: In our analysis, we added the least cost reference technology, and the least cost reference technology consistent with ISO New England's findings is a combustion turbine currently. So from an investment perspective, those would be the resources that would come in ahead of other resources that would essentially be less competitive on a per-unit of capacity basis. It's also actually quite intuitive. If you look at the supply mix we currently have in New England, we have a lot of baseload resources. So -- and because of the achievements of state policies to contain demand growth through energy efficiency programs as well, our total energy consumption is not anticipated to grow very strong in the longer term in this region.

MS. GREEN: If you would direct your attention to CLF 002-005, please. LEI states that it did not explicitly model New York electricity markets for the analysis in this case. So I wanted you to sort of explain the next sentence where you talk about analyzing nuclear retirements in New York. Can you walk me through what that analysis consisted of, please?

MS. FRAYER: So we should step back. I think this question is being generated based on a specific part of our report, page 21.

MS. GREEN: Right, that's correct.

MS. FRAYER: On page 21, where this is first discussed, and it's in relation to specific nuclear retirements in New York, it's in the context of the interchange or the level of imports and exports between New York and New England. And we have to recognize as part of our modeling that New England is not an island. It's receiving energy from a variety of neighboring control areas. And so in trying to create expectations of the future, we need to take into account expectations of the neighboring markets and what kind of market dynamics they each face. For example, in New York the market will be, over the forecast timeframe, seeing a shift in its supply mix because of nuclear retirements in the longer term. The New York market too, and I think it's referred to in our answer, will also be seeing renewable generation development as part of its own state policies. We can also shift our

attention to other interconnected markets as well to understand what's going on in the Canadian markets and how that dynamic, as well, is going to affect New England. But that's -- the whole purpose of that is to identify the fact that we are cognizant that New England's not an island and that our import and export inputs to the modeling have to be consistent with our professional views about what's happening in those neighboring markets.

MS. GREEN: Is the analysis of New York's markets that you've just described -- have you already provided that in response to any data requests?

MS. FRAYER: The analysis of New York -- so we routinely model all North America markets. That's something that anybody can purchase from our online website to see where our forecasts are. So through that multi-client analysis that we're doing on a semi-annual basis, we have an understanding, a deep understanding of what's happening in those markets. And that then gets reflected in detailed studies like this when we're doing them and understanding the import/export relationships. But we didn't actually run a New York market model for this assignment and, therefore, there is no New York modeling data that's provided as part of this case.

MS. GREEN: Was LEI asked by the Commission to consider the impacts that the NECEC project would have on future electricity generation in Maine?

MS. FRAYER: I'm a little confused. What do you mean by future electric generation in Maine?

MS. GREEN: And I apologize, I did ask that in a confusing way. As opposed to impacts on existing generation which you talked about various retirements and deferments -- or deferrals. But did you consider the -- the impacts on development of electricity generation in Maine?

MS. FRAYER: So let me step back and say that the Commission asked us a broad question, what are the impacts of NECEC on the electricity sector. They didn't try to isolate and study you study only this aspect of it or that aspect of it. It was a broader assignment. In our work and analysis, when we look at modeling a project like this, we're not keeping the electric generation sector constant as it stands today. We're actually developing a view of what kind of new resources will come onto the system in New England as a whole. Some resources will be policy driven. Other resources will be driven by economics. That all factors into the analysis, and I believe our analysis reflects all that for the region as a whole and for Maine as well.

MS. GREEN: That's all I have for now. I'm going to switch over to my colleague.

MR. TURNER: Good morning. My name is Phelps Turner. I'm an attorney at Conservation Law Foundation.

MS. FRAYER: Good morning.

MR. TURNER: In LEI's report, you indicate that results of your modeling show that the proposed project would reduce annual CO_2 emissions from New England generators by approximately 3.6 million metric tons. Is that correct? I can point you to -- that's on page 30, the first sentence in Section 2.5.

MS. FRAYER: Yes, that is correct. It would reduce 3.6 million tons of CO_2 emissions from New England resources.

MR. TURNER: Right. I want to turn now to CLF -- data request CLF 002-002. In this request, CLF asked why LEI did not model emission reductions in Maine specifically, and in response LEI stated that, in part, quote, "Carbon emissions in the power sector cannot be measured within specific political boundaries," unquote. Is -- that was part of your answer, correct?

MS. FRAYER: Yes.

MR. TURNER: Okay. In its petition, CMP represented that it expects NECEC to reduce Massachusetts's annual share of greenhouse gas emissions by at least 1.4 million metric tons as compared to the status quo, and then goes on to indicate that Maine's share of these reductions would be 264,000 metric tons. I can point you to the parts of the petition if that would be helpful, but those are the numbers that they gave in their petition. So my question for you is if carbon emissions in the power sector can't be measured within specific political

boundaries, are CMP's representations about reductions in Massachusetts and Maine reliable?

MS. FRAYER: So I think the -- let me answer the question high level. And if Eva wants to jump in, she can do a more detailed comparison for you between the carbon emissions reductions on the New England basis that we understand CMP's consultant estimated and ours. It's -- we have, I think, also a DR that talks about that a little bit about that. But generally speaking, I think the nuance here is that we cannot provide directly from our model an estimate of carbon emissions reductions that we can associate with Maine without making some assumption on how to allocate total regional carbon emissions. And I do think that CMP in its petition, and maybe something you should follow up and ask them as well through discovery just to make sure you understand how they did it, but they are probably doing a pro rata allocation of the regional emissions reductions based on maybe peak load shares or total energy consumed for each of the states in New England. And that's reasonable. You could do that. We just didn't want to undertake making that additional assumption if our model is reporting it. I didn't want to give anybody the wrong impression that somehow our model reports out that Maine's getting this piece and New Hampshire this piece and Vermont that piece because that's not actually consistent with the simulation aspects of the model and how individual generation

units are selected to be dispatched for wholesale load, not load in a specific political location -- politically-defined location or boundary.

MR. TURNER: Okay, that's helpful. If LEI had wanted to or had been asked to do that, that's something that you could have done?

MS. FRAYER: It's -- you know, if somebody said let's assume we can allocate the carbon emissions reductions based on peak load, that's a simple calculation. So it's definitely do-able. Now carbon emissions allocations may not actually follow that form of peak load. There may be financial or other contractual obligations where certain states might argue that they have a bigger or smaller share of that. So we didn't want to wade in. It's outside of our current scope of work.

MR. TURNER: Great. I want to turn to CLF 002-003. In this data request we -- CLF asked why LEI didn't analyze emission changes in other jurisdictions as a result of the proposed project. In its response, LEI indicates, in part, that it was outside of the scope of its work. I wanted to ask you a quick question about the scope of work with respect to emissions. How was the scope of work in this case similar to or different from the scope of work that LEI's received with respect to analyzing emissions reductions in other projects?

MS. FRAYER: I think the scope of work is fairly similar with respect to general kind of requests to look at a

transmission project and how it affects wholesale markets so -- of course, we work on many different types of projects so sometimes the questions our clients ask us are very different.

MR. TURNER: So continuing on with 002-003, further in your answer, you discussed some factors relating to New York and Ontario, and I wanted to follow up on some of that. About halfway down in the answer, you -- LEI states, "In New York the generation supply mix is primarily zero emitting existing large hydro wind and nuclear." Do you see that?

MS. FRAYER: Yes, I do. And that's referring to -- it's connected to the prior statement -- sentence which is referring specifically to upstate New York, just for context. The two sentences are linked.

MR. TURNER: Okay, so to clarify, is the statement about the mix being primarily zero emitting with respect to upstate New York?

MS. FRAYER: Yes.

MR. TURNER: I see. I think in the next sentence you indicate New York state has a clean energy standard which dictates that 50 percent of load needs to be served by renewable resources by 2030. As part of developing this answer and I guess its report generally, did LEI -- has LEI assessed whether and to what extent New York is on track to meet that standard?

MS. FRAYER: I don't think we've necessarily gone

back and tried to -- we haven't had a project that asked us to try to assess how far along New York state is, but in our modeling that I mentioned earlier, we're routinely looking at forward-looking conditions across various regional power markets across North America. We are anticipating that there will be incremental new generation, renewable generation, that needs to be built in order for New York to achieve ultimately its clean energy standard.

MR. TURNER: Are you generally aware that the proposed operational date for this project is 2022?

MS. FRAYER: I believe we had some back-and-forth questions at the May technical session when CMP was -- made itself available to questions about their project. So I vaguely recall discussion around the COD date.

MR. TURNER: Okay. Are you generally aware that it's around that time, 2022?

MS. FRAYER: Yes, I guess -- subject to check, yes.

MR. TURNER: Sure. The reason I'm asking about 2022 is I was -- I wanted to ask whether your response here with respect to the diversion from -- potential diversion of energy from New York, whether this analysis applies as of the proposed service date or some date after that.

MS. FRAYER: So the -- in our modeling, we chose 2023 as the starting kind of in-service date of operations for the project, but that's close enough, so we're not going to quibble

over a year. In the answer to CLF 002 -- I can't see -- 003 where we talk about the possibility of how energy flows out of Quebec may affect Quebec's exports to other markets, it was written in a more general sense to cover a timeframe that's consistent with the operating profile that we captured in our modeling. But it's not looking at any singular specific year. There's a lot of dynamics that are occurring in New York and Ontario that interplay in specific periods. And even dynamics within Quebec itself as well.

MR. TURNER: Sure. It's the next sentence, I believe. So even if -- and I understand that towards the top of this response you -- it's phrased theoretically. So I understand we're operating under a theoretical situation. You said in your response so even if any power is diverted from upstate New York, it will likely be replaced by existing or new renewable resources. Does -- in making this statement, does LEI anticipate that these new renewable resources would be available as of 2022 or 2023?

MS. FRAYER: I think that there are a number of existing renewable resources that have spare capacity currently in upstate New York. And at the same time, we are anticipating that there will be a steady kind of build out of certain renewable resources in upstate New York. Wind being the primary one there. Also, some solar as well because of the aggressive kind of policy goals of the state. So the

combination of those two in our opinion will be kind of the underlying source for this -- for the uptake, if you will, in energy demand in that part of the region if, in fact, and that's a big if, if any of the exports that Quebec currently makes get diverted to other markets.

MR. TURNER: Sure. Has LEI -- you mentioned some existing spare capacity and potential new capacity. Has LEI quantified that?

MS. FRAYER: In the context of this project, we have not done any year-by-year specific analysis.

MR. TURNER: Okay. I have a few similar questions about Ontario which is the -- this part that follows in its response. LEI states, "Hydro-Québec's power being diverted from Ontario could potentially be replaced by increased nuclear production or other renewables (Ontario will have nearly 6,000 megawatts of wind by 2020 according to IESO)." Do you see that part?

MS. FRAYER: Yes.

MR. TURNER: Okay. Has LEI assessed whether and to what extent Ontario is on track to meet this target?

MS. FRAYER: Again, we do really extensive modeling analysis and advisory of future market -- electricity market issues in Ontario. In the context of this project, we haven't tried to identify where Ontario is with its renewable build out, but it's had a very -- you could say successful from

somebody's perspective -- program of attracting a lot of renewables through the long-term contracting processes it has. So there is significant capability, and it also has what we call a surplus baseload generation problem. And it's actually designed tariffs specifically for its hydro so that the nuclear doesn't have to back down in its operations as much, and they spill water to deal with excess nuclear hydro and renewable resources off peak. So I don't have a direct answer in terms of a catalog of where they are relative to their current expectations on buildout, but I know for a fact that they have significant low-cost resources and low-emissions or zero-emissions resources.

MR. TURNER: Yeah, okay. Thanks, that's helpful. My last question about Ontario is you mentioned that there are a lot of variables here including various policies. Would you also agree that one of the variables could be politics, for instance, the election last week of a conservative government in Ontario? Would you agree with that?

MS. FRAYER: Politics unfortunately always has a big play in the electricity markets around the world. So yes, politics can change any sort of dynamics, including politics in this state.

MR. TURNER: Okay. In your answer here about theoretical diversion of exports, you didn't mention New Brunswick, and I was wondering why.

MS. FRAYER: Because of our prior analysis and understanding of where Hydro-Québec is selling its export -- what we call export tagged energy, basically energy that it doesn't need to meet internal load, we think that the markets which it would look to redirect energy from would be the lower-priced markets. And that would be rational, profit-maximizing behavior on their behalf. And the lower-priced markets would be Ontario and upstate New York.

MR. TURNER: Okay. I want to turn to CLF 002-010. In this question, CLF asked LEI whether it's estimate about 3.6 million metric ton reduction in New England accounts for LEI's estimate in its report concerning 580,000 metric tons of CO_2 emissions from the generation of hydroelectricity. And in response, LEI stated in part that the 3.6 million doesn't account for the 580,000 amount. And I just want to ask if one did account for the 580,000 metric tons that you estimate in your report, that would reduce the 3.6 million number, correct?

MS. FRAYER: Yes, if one would want to net it out, it would basically result in about a 3.1 million metric ton number on a net basis.

MR. TURNER: Right. I want to turn to CLF 002-0017. In this question, we asked whether LEI had -- whether there are any other emissions associated with the production of hydroelectricity, and LEI's stated in its response that it's not aware of whether other emissions would be applicable to the

energy flows on NECEC. Why -- so why did LEI decide to -- not to make itself aware of other potential emissions?

MS. FRAYER: In our modeling of electricity markets, our focus is on carbon emissions. So we don't look at other potential I would say classes of pollutants that might be categorized as greenhouse gas.

MR. TURNER: Okay. Sorry, I guess a quick follow up on that would be was -- so LEI wasn't asked to assess emissions other than carbon dioxide, correct?

MS. FRAYER: So I believe our scope of work was to look at the electricity market impacts and macroeconomic impacts of the project. And as part of that, because I think the Commission staff are well aware of our modeling capabilities, they knew that we could look at carbon emissions. I think it was referred to as greenhouse gas emissions maybe in the terms of reference, but essentially in our mind, when we're doing our electricity market modeling, that would be carbon emission, CO_2.

MR. TURNER: And do -- is that the industry standard, to focus on carbon dioxide and not on other greenhouse gases?

MS. FRAYER: I think from an electricity market modeling perspective, it's quite common to do it that way.

MR. TURNER: And that's typically what LEI's done in other analyses, is that correct?

MS. FRAYER: Yes.

MR. TURNER: Well, let me ask it a different way. Has LEI ever assessed anything other than carbon dioxide emissions from a proposed project?

MS. FRAYER: Well, years ago, when I started in this industry -- I'm going to date myself, but we had various other types of emissions regulations that were being implemented like the acid rain program for sulphur dioxide allowance trading and so forth. So -- and when we used to have significant coal- and oil-fired resources on the market, we would measure those as well, sulphur dioxide and NOx emissions for different types of studies. But with respect to greenhouse gas, our focus is generally on carbon dioxide.

MR. TURNER: Okay. I guess my last set of questions is about -- actually, let me turn your attention to CLF 002-019. And in that request we had asked about communications between and among LEI staff and then also between LEI and the Commission. And you mentioned a phone call that occurred on May 16th in your response, and I guess I'm -- I'd just like to know what the Commission staff's response was to your report with respect to emissions reductions.

MR. SIMPSON: Excuse me, I need to interrupt you. This is a response that was prepared by staff and not by LEI. So you can try to answer that one from your perspective, but I just wanted to clarify that it's an answer that LEI did not prepare.

MR. TURNER: Okay, thanks. All right, thanks. Let me take a step back then. Have -- in this response that staff prepared, they allude to a phone call that occurred between LEI and the staff on May 16th. And in this response they say the PUC staff alerted LEI staff their analyses concerning CO_2 emissions and/or emissions reductions from the NECEC would likely be challenged by other parties in the proceeding. Were you on that call?

MS. FRAYER: So I can't remember the specific dates, but I do believe that we had a quick chat with staff before we filed our report. So that's probably that call.

MR. TURNER: Sure. So going back to that --

MS. FRAYER: Let's assume it is.

MR. TURNER: Sure. And I'm not so concerned about the date. I just -- I'm asking based on your recollection of conversations with the Commission staff what their reaction was to your report with respect to environmental benefits as you've titled it in Section 2.5.

MS. FRAYER: I think that call was really focused on getting kind of reactions from the Commission staff because they were becoming more familiar with some of the other intervener evidence which it wasn't in our scope of work to follow. So we weren't really following the interests of various other parties and the evidence that they were submitting because I think evidence was submitted maybe in late

April by some parties. So that -- it was really more of a comment to us and a point taken. The report was not changed in any way in response -- in hearing, I guess, that comment back. It was more about making sure that -- well, that we were aware of it.

MR. TURNER: Okay, thanks very much. No further questions.

MR. SIMPSON: Before we move on, I just wanted to check. Do you still have confidential questions for LEI? In your pre-conference memo, you indicated perhaps as many as 30 minutes. I'm not going to hold you to it. I just want to have a sense for whether you do or not.

MR. TURNER: Yeah, thanks, Chris. That was probably a liberal estimate. It would probably be more like five or ten minutes.

MR. SIMPSON: Okay. But you still do have some confidential questions?

MR. TURNER: Yes.

MR. SIMPSON: Okay, great. Thanks. Okay, I think I'd like to go now to NRCM.

MS. ELY: Thank you. My name is Susan Ely for NRCM. I guess I will sort of leave off where -- start where Phelps left off, with some greenhouse gas questions, Section 2.5 on page 30. And I just wanted to confirm from your earlier discussion with Phelps and in response to NRCM 001-007 that you

didn't evaluate other greenhouse gas emissions and that that would also include methane emissions from hydroelectric facilities.

MS. FRAYER: We did not evaluate other emissions.

MS. ELY: Okay. And then again, another follow up to Phelps's questioning on your analysis of the 3.6 million metric ton reduction figure. In not including the CO_2 emissions from -- or the estimated CO_2 emissions from the hydroelectric facilities in Quebec, in essence, your analysis is source neutral if it's from outside of New England. Is that a fair characterization? Like, in other words, it wouldn't matter if it was coal or nuclear or wind or hydro if you're going to exclude the source because it's not a New England generator, is that correct?

MS. FRAYER: I wouldn't characterize our analysis that way. In part, maybe I'm not understanding it. The way I would say it is that the 3.6 million metric tons of carbon emissions reductions is based on the specific generation resources that were displaced in the New England market. And so there might be some gas, some -- maybe some -- a few hours of oil-fired generation being displaced. So that's really the, I guess, if I can use those words, the source or underpinning of how we calculated the 3.6 million number.

MS. ELY: But it doesn't take into account the source of the energy coming into the system?

MS. FRAYER: It doesn't -- well, I guess I would say that that wasn't the focus of our analysis. There is a presumption, though, as described in our report that the source would be coming out of the Hydro-Québec system. And as we know, the Hydro-Québec system is composed of significant large hydroelectric resources. That's the whole calculation of an additional, I guess, variable that is trying to capture lifecycle costs of -- sorry, lifecycle emissions of large hydroelectric resources.

MS. ELY: Okay. And again -- Phelps took a lot of my good questions. But again, piggybacking off of his earlier questions about your analysis, I understand that you didn't model for this particular exercise the emissions in the -- emissions from changes in the energy markets in other regions, Ontario, New York, and beyond. But would you say that an analysis looking only at New England emissions is sufficient to understand the global impact emissions from the -- this particular project?

MS. FRAYER: So I don't think it was in our scope of work to understand the global impact. That said, I think the cornerstone of doing that is to understand the direct effects of the energy flows on NECEC on emissions in New England. So that would be critical to trying to get that understanding, and you have that from our current study. We didn't study or model as part of this project the possibility that there would be

redirected energy flows from other markets to fill up the NECEC line. But as I've answered more qualitatively in the response to the CLF DR, I don't believe those would result in material changes of emissions in those other markets.

MS. ELY: Okay. Switching gears. In response to NRCM 001-001 which refers to Section 5.2.1 on page 55, you looked at the share of local spending and state that you -- let's see, where is it. Sorry. So it's 55 to 56. And on the top of page 56 you say that you compared what LEI has observed in other engagements involving other HVDC transmission projects. And I was wondering if you could share what other projects you were referring to.

MS. FRAYER: Some other projects that I've worked on are in the public domain, and some, in fact, many, are not. I can mention the ones that are in the public domain. Two come immediately in mind, and it's because I've worked on their siting cases. That would be Northern Pass which is an HVDC project and -- here in New England. Another one would be Champlain-Hudson Power Express which is a proposed transmission project, also HVDC, in New York. There are many other projects that I have looked at and have reviewed information on that are using that technology, but I can't disclose my affiliation or association with them publicly because of -- my work was confidential.

MS. ELY: Would it be a question that's more

appropriate for the confidential session?

MS. FRAYER: I don't think I would be able disclose it there either. That would put me in violation of my non-disclosure agreements.

MS. ELY: Could you, for the ones that are publicly available or maybe for the ones that are confidential, summarize them without naming what the local shares were in those other projects or --

MS. FRAYER: No, I don't think so. I just named two projects. That would be pretty much giving away their data. Although I think it's possible for someone to review public information and maybe come to some understanding of their estimates. As part of this answer, we've also -- I think we had a question about this in one of the DRs as well. And we acknowledge -- I think it's DR GINT-001-043. So have a look there, but we've acknowledged that different -- these projects are -- have unique aspects to them, and there are different characteristics to all of them, even within the broad spectrum of using the same technology. And so there may be legitimate, I would say, technical reasons for different levels of local versus non-local spending of the capital costs. You would really need to have a technical engineer opine on those. So it's not within our bailiwick or our scope of work at the moment, but we wanted to raise it in the report and just note it. Nevertheless, for our analysis we used the same amount of

local spending and budget estimates that the applicant, CMP, provided us.

MS. ELY: So this -- you may have just answered this question with your last statement, but are there any factors that you're aware of in Maine that would impact an analysis of the local spending?

MS. FRAYER: I don't have any specific factors in mind so, again, I feel it's -- this is much more of a technical engineering question.

MS. ELY: I think that's all I've got.

MR. SIMPSON: Let's go to the generator interveners now, and I want to note that I'd like to take a break for lunch at around 12:15. Yes, sir?

MR. MURPHY: NextEra?

MR. SIMPSON: Oh, I'm sorry. I've got the wrong order on my paper here.

MR. MURPHY: No problem.

MR. SIMPSON: And actually that may work out perfect. Your estimate might fall in between now and lunch. So let's go to NextEra. I apologize for that oversight.

MR. MURPHY: No problem at all. My name is Brian Murphy. I'm with NextEra Energy Resources. I'm an attorney with NextEra. And I'd like to refer you to Figure 1 in your report. I'd like to focus on the retail impacts benefits to Maine. And I don't have questions about the figures so let's

assume the figures are correct. Do you have an opinion on the mechanism that would be used, tariff mechanism or otherwise, that the retail ratepayers would actually realize these benefits?

MS. FRAYER: So if I can step back first, and character -- or try to characterize these electricity market benefits, they're essentially measuring the fact that the -- in the future with this project in place and energy flowing on the project and capacity being sold on the project, the market prices in the associated wholesale power product markets will be lower. So this is essentially an exercise where we're saying if this project is built, this is what the price would be. And we're also saying if this project isn't built, then the prices will be somewhat higher by certain dollar amounts. So I think from a mechanism perspective, I think the expectation is that the consumers, electric consumers, in Maine would see the market prices that are associated with our project case. There wouldn't need to be, in other words, a tariff mechanism or some sort of regulatory scheme to deliver these benefits. These benefits are going to be a function of almost a counter-factual world but for the project.

MR. MURPHY: All right, I guess I want to test that a little bit. So in other jurisdictions, let's take the ANE case for example, there were a specific tariff mechanism where the wholesale benefits which you estimated here would flow back to

retail ratepayers. And whether you agree with the tariff or not is -- but I'm still struggling how the industrial customers or a residential ratepayer would see these benefits or would they be captured by an aggregator? Would they be captured -- could they be captured in a -- in the space between the wholesale market and the actual retail tariff?

MS. FRAYER: So I'm not familiar with the case or the jurisdictional reference you made earlier about an -- so I won't speak to that tariff scheme. But maybe I can try one other time to answer your question which is let's look at typical customers and different classes of electric customer here in Maine. Let's take a customer that is themselves, and we have a few, not very many, but that is buying directly from the wholesale market. They would be able to, according to our analysis, buy energy at a lower price than in a situation or a world where this project wasn't built. They would be -- even if a customer is buying energy, representing itself as load in the wholesale markets, it's still going to be responsible for the overall system share of capacity market costs. Their share of capacity market costs would be lower because of the introduction of this resource as capacity in the capacity market.

Let's take a household kind of on the extreme spectrum. A residential customer is going to be served by a retailer, be that somebody that's been selected under the

utility's -- and I'm going to get the terminology wrong but standard service process or a competitive retailer. And that retailer would be buying power from the wholesale market in order to meet the needs of its customers. That power, according to our analysis, is cheaper. So the retailer, through the competitive kind of retail market dynamics process, will then be providing to the end user the residential customer a lower cost product as well. So that's the mechanism, but it's a market-based mechanism. I didn't anticipate that there would be a specific tariff constructed to account for these.

MR. MURPHY: Thank you. That's all the non-confidential questions that we have.

MR. SIMPSON: Great, thanks. And do you anticipate having confidential questions for this panel?

MR. MURPHY: About five minutes.

MR. SIMPSON: Yeah, okay. Thank you. Okay, let's go to the generator interveners, and again, let's shoot for breaking at around quarter after.

MR. SHOPE: Thank you. Well, I guess it's still a couple minutes of the morning left so good morning, Ms. Frayer. My name is John Shope and, as indicated, I represent Calpine Corporation, Vistra Energy Corporation, and Bucksport Generation, LLC. I want to direct your attention, if I could, to the generator intervener interrogatory and response 001-008. And the last sentence of that states, quote, "Transmission

losses were not simulated in the POOLMod analysis for this project because NECEC was assumed to have no material impact on transmission losses affecting the system." So the first question is just to confirm, when it says "assumed," does that mean that London Economics did not do any analysis of whether or not NECEC would likely cause any impact on transmission losses?

MS. FRAYER: That's correct, we did not do any type of analysis on this topic.

MR. SHOPE: Okay. And do you have any -- was there any particular reason why it was assumed that there would be no material impact on transmission losses from NECEC?

MS. FRAYER: Given the type of project, the type of transmission investment this project is, it's an HVDC project, and given its general point of interconnection in the system, based on our professional judgment, we thought it was a reasonable assumption to make to assume that it wouldn't have any negative or positive changes on the marginal loss algorithms that the ISO New England uses to determine the marginal loss component of locational marginal processes.

MR. SHOPE: Why was that in particular, though? What in particular about the location of the point of injection caused that assumption to be made?

MS. FRAYER: Well, it -- specifically that its locations in the Maine zone, in our professional judgment,

wasn't going to make a big impact. So it --

MR. SHOPE: Well -- and why in particular? What about -- what is it about the Maine zone that caused you to believe that?

MS. FRAYER: Essentially, we were talking about a system -- so let's step back. The marginal loss function in locational marginal prices of the ISO is basically estimating -- I'm going to try to make it simple. It's going to be a little hard. But it's essentially estimating the financial consequence of transmission losses, not the physical transmission losses. And the financial consequence of transmission losses is going to be somewhat correlated by the distance. It's going to be somewhat impacted -- the distance between a resource and the distance between the load, it's going to be impacted also by other nuances on the AC system, in our professional judgment, because this was an HVDC asset. So it would be kind of similar on the transmission system as a generator from that respect, a large generator. It's our practice not to consider transmission -- major changes in the financial component in the LMP of transmission losses. Depending on the type of technology, we may have sought advice from a transmission flow engineer if it was, for example, an AC-based system because it might have a different ramification on the financial component of LMPs.

MR. SHOPE: Okay, so basically -- so let me break

that down. As I understand it, so for purposes of losses calculation, the -- with the HVDC line coming into Lewiston, it would sort of be the equivalent of building, like, a 1,200-megawatt generation plant right there in Lewiston, is that fair?

MS. FRAYER: Yes, that is the basis for our conclusion, that it would be equivalent to having a large baseload generator.

MR. SHOPE: Okay. And I think -- and as I -- if I make sure I understand your testimony correctly, you were saying that basically it's the -- your general practice at London is that when you're looking at, for instance, somebody constructing a new 400-megawatt power plant, you wouldn't actually go out and try to figure out the effect on losses on the associated AC distribution system?

MS. FRAYER: Within this part of the New England control system. I think if they were building it at some periphery point behind additional AC transmission interfaces that are congested, we might then get advice of a transmission engineer.

MR. SHOPE: Okay. Well, would you have wanted to, for instance -- if you were going to make this analysis, would you have wanted to compare how much power was being injected at Lewiston in relation to the existing supply in Maine and the demand in Maine existing?

MS. FRAYER: No, not for this aspect. That analysis is useful for other things but not for the financial component of transmission losses and LMPs.

MR. SHOPE: Okay, but I wasn't asking about the financial component. I was actually asking about, you know, transmission losses. So that would be -- that -- line losses are, in fact, one of the elements of congestion, isn't that fair?

MS. FRAYER: Well, I thought we were asking about this DR which is talking about the transmission loss component LMPs which, as I said, is not the same thing as physical transmission losses.

MR. SHOPE: Okay. All right. Let me back up, actually, and see if maybe we can get this more generally. How does the -- does the TransMod system actually take into account congestion? I'm sorry, POOLMod, I apologize.

MS. FRAYER: Yes, POOLMod does take into account congestion which is another component of locational marginal pricing.

MR. SHOPE: Okay, and how does it do so? How does POOLMod actually break that out?

MS. FRAYER: POOLMod knows the location of load and knows the location of generation and knows the operating limits of key transmission interfaces that ISO New England themselves use to monitor and operate the system and essentially solves

for the least-cost dispatch taking into account those locational characteristics of the transmission system and of generators and load.

MR. SHOPE: So why doesn't your model break it apart?

MS. FRAYER: You would have to run the model on copper plate, and then with the representation of the network and location features to be able to isolate it, and we don't run it on copper plate typically. Unless the client asks us in advance to break it up, we don't actually have our model do it.

MR. SHOPE: Now I want to ask some questions about the potential capacity market benefit of the proposed NECEC project. And just to start out with the basics, as I understood it, you ran sort of two scenarios; one where it's assumed that the project clears the standard forward capacity auction. That's scenario number, is that fair? Or that is one of the scenarios that you modeled?

MS. FRAYER: Yes. I would just want to refine it a little bit. The scenario one, as you call it, is basically starting off with an assumption that the minimum offer price of the project will not be constrained by the clearing price that the model -- the forward capacity auction simulator determines with this resource clearing. And so that's scenario one.

MR. SHOPE: Okay. So -- and as I understand it, you did not actually do any calculations to determine whether it was likely or not that the minimum offer price rule would or

would not permit clearing in the forward capacity auction.

MS. FRAYER: So I think we had a discussion earlier this morning about this.

MR. SHOPE: Yes, and that's -- and to be honest with you, I'm still confused. So that's why I'm asking the follow up.

MS. FRAYER: Okay. We did not calculate an -- so for those who are probably hating me for all the acronyms we're using, we did not calculate an explicit minimum offer price level. This would be in the form of an explicit dollar-per-kW month that a new entrant like the entity selling capacity on the NECEC project would need to have set up for it. They would go through a whole process with a market monitor to vet their information to set up this -- basically a price floor for its participation in the capacity market. So we didn't calculate that value, but we can see the clearing price with this project clearing at its full stated capacity supply levels. And we -- I know -- I can't disclose what the price is, it's confidential, but we can talk about it later if you want to. But on that basis and given our professional judgment, we thought that the minimum offer price for a project like this should be sufficiently below that to have not constrained it in clearing, the primary action.

MR. SHOPE: So did you -- did you actually collect any materials on the inputs into how the minimum offer price

might be calculated in order to, you know, get a sense, even a back-of-the-envelope sense, as to whether or not the project would likely clear the FCA?

MS. FRAYER: We did not make any concerted effort to even do any bar napkin calculations of the MOPR. I believe there is some information in the record already that CMP provided that could be used by somebody to do that. Not all the information but some information.

MR. SHOPE: But you didn't actually look at that information to which you've just referred that CMP has put in at least for this purpose?

MS. FRAYER: We did not attempt to do a minimum offer price calculation of the project.

MR. SHOPE: Okay. And did you take any -- did you look at what might be involved on the Canadian side of the border to make the project operational?

MS. FRAYER: I believe there may have been some descriptions in the application, but I can't recall specifics.

MR. SHOPE: Okay, so you didn't take that into account when you were thinking about whether or not the project might clear the forward capacity auction?

MS. FRAYER: Not specifically with this project, but we have spent excruciating amount of time looking into it for other projects that are coming from Quebec. I'm very familiar with the way it works; I just don't have the number in hand for

this project.

MR. SHOPE: I see. So these are the projects where you can't tell us what the project was or who the client is?

MS. FRAYER: No, this is for the Northern Pass project which was also essentially requiring a tie in to the Quebec system.

MR. SHOPE: Okay. Now is -- as I understand it, the -- in what I've called scenario where the project clears the forward capacity auction, when you came up with total numbers of benefits which are in your report, in Figure 1 of your report, 70 percent of the benefit came from the assumption that -- 70 percent of the benefit came from the -- was in a scenario where it was assumed that the forward capacity -- that the project cleared the forward capacity auction, is that correct?

MS. FRAYER: Of the electricity market benefit we're speaking about.

MR. SHOPE: Yes.

MS. FRAYER: Yeah, that's a ballpark number. I think I would have to pull out my calculator. I can't do division that fast. But the ballpark number is good for our discussions.

MR. SHOPE: Okay. Now, in -- there was a second scenario that you modeled where the project did not clear the forward capacity auction presumably because it didn't meet the minimum offer price rule. Is that fair?

MS. FRAYER: Essentially, yes. It's not in Figure 1, but it's discussed on top of page 11 in the context of reviewing these results. And to be more specific, this alternative view, what it -- what -- how it builds up to that is that we assume, because of the MOPR, NECEC is unable to clear the primary auction or the forward capacity auction and then goes on to participate in the secondary or substitution auction -- apologize everything seems to have two names these days -- and clears based on our analysis because there is sufficient demand in that substitution auction for it to clear as a sponsored policy resource.

MR. SHOPE: Okay. And in -- for purposes of that analysis of the second scenario, the plants that you assumed would be retired were not in Maine, is that correct?

MS. FRAYER: So it's not an assumption, to just be clear. So we have, as part of our forward capacity market simulator, a full representation of the current market rules in New England between the primary auction and the substitution auction. And the substitution auction essentially requires that certain generators nominate themselves to retire. They are generators that are seeking retirement, seeking essentially a severance payment for retiring, out of the substitution auction. And there is a clearing process that basically matches up those resources that are seeking to retire with the state-sponsored policy resources that are seeking to acquire a

capacity supply obligation.

MR. SHOPE: Now your forward capacity auction simulator does not actually model by zone within New England, though, is that correct?

MS. FRAYER: It could if there was, yeah.

MR. SHOPE: Okay, but you didn't model it by zone for this purpose?

MS. FRAYER: We actually tested it, and based on the analysis that's going into our base case and project case, there is no price separation. So the model is set up to reflect the zonal definitions that the ISO New England has created in the market rules.

MR. SHOPE: Okay, well, let me follow up on that. Did you determine what the maximum capacity limit would be under Section 12 of market rule one?

MS. FRAYER: We have to -- we basically have -- under the current zonal definitions, we have the information for the northern New England zone. So yes.

MR. SHOPE: Okay, but --

MS. FRAYER: But that's only one piece of it because you actually need the full local demand curve.

MR. SHOPE: Okay. But -- that's right, and the -- so Maine has been the subject of discussion as being modeled as a separate zone, correct?

MS. FRAYER: It has been subject to some discussions,

but the ISO has not actually created that aspect or the local demand curve necessary yet. Or maybe not even decided. I haven't followed it closely.

MR. SHOPE: But if we were to add another 1,200 megawatts of injection into Maine, that would affect the decision as to whether or not Maine would be modeled as a separate zone. Is that fair? If you know.

MS. FRAYER: I'd have to think about it. I think I would agree that you're adding, but I would think that there are other contexts that go into the price separation of the capacity market zone. It's not as simple as supply minus demand or demand minus supply.

MR. SHOPE: So what -- in your view, what are those other items that would have to be considered in order to determine whether or not Maine would be modeled as a separate zone.

MS. FRAYER: To actually do a thorough empirical job on that question, you would need to have the local zonal demand curves, the equivalent of the MRI for the system, but for Maine so you would be able to reflect that because it's not linear in terms of -- again, that's why I said the simple math doesn't work anymore.

MR. SHOPE: Sure. So just hypothetically though, if the -- if Maine were to be modeled as a separate zone, that would affect which units would be retired as a result of New

England Clean Energy Connect clearing the capacity auction, either standard or substitution, is that fair?

MS. FRAYER: No, I don't think that, as a general statement, holds. It's not universal.

MR. SIMPSON: John, excuse the interruption for just one second. Toby, how are you doing? You ready for lunch pretty soon? Okay, so I'm sorry to interrupt. I know you're going. If you could just come to a good break point in the next five minutes, that would be great.

MR. SHOPE: I've had that in mind.

MR. SIMPSON: Okay, yeah, good, but I don't want to interrupt the flow here. So go until you need it -- until you're finished, but please do so in the next five minutes.

MR. SHOPE: Sure. Let's just break those out. So take the substitution auction. So if Maine just -- I know you don't think it -- you think -- you're not necessarily sure that it will or won't happen, but if Maine were to be modeled as a separate zone under the ISO New England rules, that would affect whether the generators that were -- would be retiring as part of the substitution auction process -- it would affect whether they were in Maine or some other part of New England, is that -- and you -- would you agree with that general proposition?

MS. FRAYER: So I think you're -- let me restate it in my words because I think there's a missing gap somewhere

there. So even if we don't agree with the reality of the hypothetical but let's assume for now the hypothetical that Maine is modeled as a separate zone.

MR. SHOPE: With NECEC.

MS. FRAYER: And we have to assume a -- because you're asking really about the substitution auction so I'm trying to make it -- my way to there. So in order for the substitution auction to require that NECEC swap out capacity supply obligations with Maine-specific generators, a few things have to happen for that to happen. So the first thing is that Maine is modeled as a separate zone. Then the next thing that has to happen is NECEC does not clear in Maine because, otherwise, it wouldn't be going to the substitution auction. And then the third thing -- and the second and third thing are the problems. They're not really compatible. The third thing that has to happen is that even though NECEC doesn't clear and Maine is being modeled as a separate zone, Maine has to actually clear with its own price in the primary auction in order for the interzonal capacity constraints to hold in the substation auction. And I actually don't think that it's very likely that Maine would have a significantly different zonal capacity price if NECEC is also not clearing to contribute to that in the primary auction.

MR. SHOPE: Just bear with me. Let's assume that -- so actually let me simplify this. If Maine were to be -- if,

contrary to your supposition that the substitution retirement plants didn't have to be in Maine -- let's just assume that that isn't the case and that they do have to be in Maine. Would that affect your calculation of the economic benefits to Maine of this project?

MS. FRAYER: So we're talking again about the substitution auction, and I -- it's much easier to do all this in modeling, of course, because the purpose of models is to be able to show you things that your brain can't connect necessarily on a piece of paper or bar napkin. So I would say that a lot of what I say needs to be further tested. But if we're saying that there's a set of events which I am actually -- the set of events is actually really important to the results but a set of events require that specific -- that NECEC swap out capacity supply obligations in the substitution auction with Maine-specific generators, my first response is the Maine-specific generators that are in -- remember it's voluntary to be in the substitution auction -- are ready facilities that want to retire. Because they have basically indicated through a retirement bid with ISO New England that they're seeking to retire. So I don't think it has very big implications to the New England electricity market modeling because the resources that are seeking retirement bids tend to be resources that are not running very frequently in the energy market and that would, if prices went a little bit lower in the primary

auction, have retired, not gotten the benefit of any severance payment but had retired already from the -- from -- through the primary auction. So the question I think then boils down to, well, does it have local macroeconomic impact, and my point is, kind of going full circle, if these are plants that have already voluntarily indicated their interest to retire and would have likely retired anyway in the next one to two years, then it's probably not a very large impact on the results. Because, in the base case, they would have retired anyway down the road in the primary auction with other supply shocks that cause primary auction prices to fall below their retirement bid. But, again, I'm suggesting this all in the context of knowing the rules and the logic. It's great to have models, and that's why we use them, to make sure we can vet the theories that we put out there.

MR. SHOPE: Sure. This is a good -- well, actually let's just say that there's no better break time that's coming up soon.

MR. SIMPSON: I hear you. Okay, so let's go ahead and do it now. And thank you. So let's take an hour. We'll come back at 25 after 1:00, and we'll resume with the questioning of this panel. Thank you.

CONFERENCE RECESSED (June 14, 2018, 12:26 p.m.)

CONFERENCE RESUMED (June 14, 2018, 1:33 p.m.)

MR. SIMPSON: Okay, let's go back on the record.

Welcome back, everybody. We are going to resume questions from the generator interveners, and just a reminder we're going to break probably around quarter after 2:00, switch witnesses. I don't expect us to be done by then. We're going to see how long we have for Mr. Whitley who's a NextEra witness who has to go today because of scheduling availability or unavailability and flight plans. And then we'll come back to LEI after that. So, John, you're up.

MR. SHOPE: Great. Thank you. Good afternoon, Ms. Frayer.

MS. FRAYER: Good afternoon.

MR. SHOPE: This morning, Ms. Tracy of Central Maine Power or of Pierce Atwood I should say for Central Maine Power had asked you some questions about some items on your resume, and I believe you had expressed that, at least in some instances, you weren't sure whether or not your engagement was public or not. And so you wanted to defer answering until you could get that cleared up. Does that generally refresh your -- or do you recall that?

MS. FRAYER: I thought the conclusion was all the ones that -- there was one where I thought that the materials were made public, and I was going to look into that. I haven't had a chance to do that, but the majority of them I do know are under confidentiality.

MR. SHOPE: Okay. Well, I recall you were asked

whether one of the projects on which you had worked was the TDI project. Do you remember being asked that question?

MS. FRAYER: I remember I was asked whether that project that was being referred to was the -- a project -- the TDI project, yes.

MR. SHOPE: Yeah. And I believe you deferred answering that, at least at that point in time. Am I remembering rightly?

MS. FRAYER: So yes. And I think I will still defer answering whether that specific project on my CV was TDI's project or not.

MR. SHOPE: Okay. So let me ask you this. I'll just -- I'll represent to you that there's an article on TransmissionHub.com by a Rosie Lum dated October 31, 2013 that reports that TDI had engaged London Economics to do the economic analysis for the transmission project that it was proposing through Vermont. Does that refresh your recollection at all that your work for -- that you did work for TDI and that it's public?

MS. FRAYER: So I'm not familiar with that article, but I will, subject to check, that it exists. I am happy to confirm that I've worked with TDI in the past. That is not, itself, confidential.

MR. SHOPE: Okay. And --

MS. FRAYER: So I've done quite a lot of work in the

public domain for them over the years as well, for that company.

MR. SHOPE: Okay. And I believe you testified that you also did work on behalf of the Northern Pass project, correct?

MS. FRAYER: Yes. I testified on behalf of the Northern Pass transmission project in New Hampshire.

MR. SHOPE: And you authored at least one op ed article in support of the project. Do you recall that?

MS. FRAYER: I wouldn't call it in support of the project, but I probably did author some op ed or give interviews at New Hampshire public radio and other places about the analysis I did on the project.

MR. SHOPE: Okay. You're just not sure whether you did an op ed piece?

MS. FRAYER: I don't know. If you can refresh my memory of what you referring to as the op ed piece that I'm promoting the project, quote/unquote.

MR. SHOPE: Yes.

MS. FRAYER: Happy to look at it.

MR. SHOPE: Okay. All right, well, there is in the record an article from a newspaper in Keene, New Hampshire in which you're listed at least as the author of an article supporting the project and saying that it should be supported. And I believe that -- and you testified in the Northern Pass

project that -- or you testified to the New Hampshire Siting Evaluation Committee proceedings that the Northern Pass project would clear the forward capacity auction. Do you recall that?

MS. FRAYER: Yes.

MR. SHOPE: Okay. And that was a contention that other parties in the proceeding disagreed with, is that fair?

MS. FRAYER: There was other parties that disagreed with my conclusions.

MR. SHOPE: Okay. And so when you -- just to be clear, when you testified a little earlier today that you were sort of leaning toward the present New England Clean Energy Connect project clearing the forward capacity auction, that was based on the work that you had done for TDI in Northern Pass. Is that fair?

MS. FRAYER: TDI is not the sponsor of Northern Pass --

MR. SHOPE: I know that.

MS. FRAYER: Okay. So sorry, maybe I didn't hear your question. Can you repeat your question?

MR. SHOPE: So you testified earlier that you -- although you hadn't run any numbers, you were leaning toward the idea of New England Clean Energy Connect clearing the forward capacity auction. So I just wanted to clarify that the basis of that lean, if you will, since you didn't run the numbers, was the work that you had done on behalf of Northern

Pass and for TDI?

MS. FRAYER: No, that's not correct. It is correct that for Northern Pass, we had done an outright, explicit detail estimate of what we believe would be their MOPR, and it was submitted in the record so anyone could -- I think it might -- it may be confidential subject to a PO, but it's in the record. I'm not going to speak about what I did or didn't do with respect to capacity markets in New England for TDI. So I don't want those two issues to be commingled. But more importantly, I think as I said today earlier, and this is from my memory, because I don't have the live transcript here, but one of the reasons I'm learning towards the scenario where I believe there should be a good possibility of NECEC clearing the primary auction is because of the capacity price that's resulting in my modeling in the primary auction with NECEC clearing. So it's not just, I guess, on the basis of the prior work we've done for other projects. It's really also about the dynamics I'm seeing in my modeling today for the NECEC analysis.

MR. SHOPE: Okay. But you would need -- for that, you would need to compare what your projected clearing price was against the cost of the project.

MS. FRAYER: We do generally have the cost of the project.

MR. SHOPE: But I think you said you didn't look at

the cost of the project on the Canadian side of the border. Is that -- didn't you testify to that earlier?

MS. FRAYER: I haven't looked at the cost of the Canadian side, but the Canadian side does not impact the MOPR in any way. And I've testified extensively in New Hampshire about why that's correct.

MR. SHOPE: And so just to be clear -- okay.

MS. FRAYER: I can explain it here, if you like, why it doesn't matter. I'm happy to do it. It's actually very intuitive once you understand the Hydro-Québec trans-energy tariff and how that works with respect to funding those transmission costs on the other side of the border.

MR. SHOPE: I just want to get back to something because I want to get back to my earlier question which is are you saying that your basis for, quote, leaning towards New England Clean Energy Collect (sic) clearing the forward capacity auction is not the prior work you have done for Northern Pass, in whole or in part?

MS. FRAYER: The prior work that we have done for Northern Pass provides some general knowledge and understanding, if you will, of how to think about the types of categories of costs that would go into a MOPR analysis. The Northern Pass project is different from the NECEC project in some ways. So there are differences and some information that I would need directly from the sponsors of the NECEC project to

do the complete MOPR which I don't have on hand. So you can't just say it's a parallel example. But it provided me, I guess, with experience and know-how that I am leveraging in this case. But I'm also saying that it's also in the context of what we're seeing coming out of our simulation models and the clearing price in the primary auction where that price lands relative to my professional judgment as to the potential range of the minimum offer price possibly.

MR. SHOPE: But I believe you testified earlier that you didn't even do a back-of-the-envelope comparison for purposes of determining whether the NECEC project would satisfy the MOPR rule.

MS. FRAYER: I didn't do any calculations, that's correct. So it is based on professional judgment and also, again, the capacity clearing price we're seeing in our modeling.

MR. SHOPE: I'd like to draw your attention to generator interrogatory 001-014 and your response. And while you're looking for that, I'll just mention that this was a question that related, in part, to the discount rate. And the answer states, among other things, that London Economics used a seven percent discount rate.

MS. FRAYER: Yes, that's correct.

MR. SHOPE: That's correct?

MS. FRAYER: Yeah.

MR. SHOPE: And so what was the basis for using a seven percent rate as opposed to, I don't know, 5 percent, 10 percent, 25 percent, some other number?

MS. FRAYER: I think we actually have another similar DR question on the same topic. And I'm trying to remember who asked it. But I can -- if I can recall and paraphrase, our understanding is that we wanted to look at the -- on one hand, and it's not the complete side of it, but on one hand we wanted to understand what the cost of capital considerations are for other large infrastructure projects when ratepayers are concerned and a kind of cost/benefit analysis is done. So the seven percent is generic but not outside the -- outside of the range plausible for other transmission owners in the region. We also -- I believe specifically we're looking at the actual RFP and the discount rate that was supposed to be used. And I believe, and it's in response to questions --

MS. WANG: Excuse me. This is Eva. I can -- so the DR -- where you have a DR response is NRCM 001-002.

MS. FRAYER: Yes, sorry. And I think it's with respect to, again, the process and the specific questions about the type of load-weighted discount rate that should have been used in the process of responding to the 83D RFP.

MR. SHOPE: Okay. So the -- if I look at NRCM 001-002, it says, "For the Section 83D RFP specifically in a response to the third set of questions and answers about the

solicitation process, it was noted in response to question 75 that the load-weighted discount rate that will be used is 6.99 percent." And then there's a citation. And this is in response to a question, "Please explain how LEI arrived at a standard seven percent discount rate." So is it your testimony that the sole reason that you picked the seven percent discount rate was that it was at least a rounding off of the 6.99 percent that was used in the Massachusetts RFP for determining the benefits to Massachusetts?

MS. FRAYER: That's one of the reasons. I said we also wanted to generally understand what a reasonable discount rate would be for considering cost benefits to ratepayers in this context. And ratepayers today pay for other large infrastructure investments based on their allowed cost of capital. So if you look broadly at the allowed cost of capital for regulated utilities in the region, it's in that range as well.

MR. SHOPE: Did you look at CMP's cost of capital in particular.

MS. FRAYER: No, I did not CMP's cost of capital specifically.

MR. SHOPE: Okay. And what discount rate did you use when you were evaluating the benefits for the Northern Pass project?

MS. FRAYER: I believe it's the same discount rate.

MR. SHOPE: Okay. And now the cost of capital would depend, in part, on who was the borrowing party, right?

MS. FRAYER: The cost of capital depends on the capital structure. So it'll depend on the credit quality of the borrowers which, in turn, will depend on potential contracts and the credit quality of the counterparties to the contracts as well.

MR. SHOPE: Yes. So a non-utility transmission developer might have a higher cost of capital, right?

MS. FRAYER: Not necessarily. It depends again how this project is going to be actually structured, if it's going to be balance sheet financed, project financed.

MR. SHOPE: It would depend on the particular circumstances?

MS. FRAYER: Excuse me?

MR. SHOPE: It would depend upon the particular circumstances?

MS. FRAYER: It would -- I would argue it would depend more on the project and the specific arrangements on the project, but it could also depend on decisions taken by the sponsor of the project and how they chose to actually set up the financial structure, yes. We were not getting into those details, by the way, when we thought about the -- a generic, I think, discount rate that we thought would be applicable, again for the purposes of measuring the potential benefits of the

project for ratepayers.

MR. SHOPE: Okay. So were there any other considerations that went into the seven percent other than the RFP and now what you're adding is the sort of generic cost of capital for utilities?

MS. FRAYER: I can't think of anything at this time.

MR. SHOPE: Okay. Nothing further for the public session.

MR. SIMPSON: Okay. Just hold on for one sec, please. Okay. Not quite. So Dot, I know that you have some questions. Now would be a good time for you to ask them. Thank you, Phelps. Appreciate that.

MS. KELLY: Good afternoon. I'm Dot Kelly. I'm in Phippsburg, Maine and appreciate the depth of your analyses. I'd like to follow up on the environmental section of your report and was hoping that you could just give me an overview of what you were trying to say within the environmental section.

MS. FRAYER: We'd be happy to. So the environmental portion of our -- let me give this back to you -- of our analysis was actually quite narrowly focused. And it's linked up closely to the electricity market analysis which is a big focus, actually, one of the two prongs of the potential impacts that we were asked to study with respect to NECEC. So we weren't asked to do a comprehensive environmental due diligence

on the project. Rather, I think we were asked to look at, as I said earlier, greenhouse gas emissions impacts which, in the context of electricity market modeling, would be the carbon emissions reductions. And that's what we --

MS. KELLY: And let me just qualify, you're always saying carbon dioxide emissions when you say carbon because methane is also CH_4 and carbon dioxide is CO_2. So they are both carbon emissions.

MS. FRAYER: Yes, I apologize for the lack of clarity in the technical terms. So we're measuring CO_2 emissions reductions. So really, that's the focus of what we term to be the environmental benefits section of the report, 2.5. It's really meant to cover and explain how we measured the carbon emissions changes because it could have -- you know, I don't think we started with the analysis presuming it would be reductions. It's more of an output of our analysis that it turns out to be reductions. But how we measure changes in carbon emissions, what kind of data we use, and assumptions to the extent any are necessary, which they generally are not, on carbon content of different types of fossil fuels that are used in the production of electricity in New England. So that was fairly narrowly the scope. And we reported the actual tons of carbon emissions avoided because of the differences in the energy -- in the dispatch of electric power -- electricity generation in the region. So that's, in a nutshell, really the

focus of that section.

MS. KELLY: And I guess the follow up to that is, given the information that's been described here which does include the fact that there's a Harvard report that has looked at Hydro-Québec with their very shallow ponds that feed their hydroelectric, that the methane emissions have been thought to be quite significant and at some points are said similar to a gas power plant for the first 40 years. Given your role as modelers and looking at things even to the point of indirect economic advantages in areas, would you now say that that should be considered in your environmental section?

MS. FRAYER: I'm not familiar with the report you mentioned. I would probably suggest that we wouldn't be able to pass judgment until we reviewed everything thoroughly and really understood aspects of it. It is important for us to always do, I would say, getting a deep understanding, a like-for-like understanding in our quantitative modeling. Our modeling doesn't report or track methane emissions of power plants at the moment. So it's not something that's easily compatible or that I'm sufficiently familiar with that I can pass judgment right now here.

MS. KELLY: Thank you very much. I guess as an aside, I'll mention that since EPA -- I believe the number is 70 times the CO_2 number and then you have to take other things into account, that when you're talking about carbon dioxide

emissions, you make it clear you're not including any methane emissions within this context.

MS. FRAYER: Point well taken. We shouldn't use vocabulary generally without at least letting people know. So in our report we're really focused on CO_2.

MS. KELLY: And it's a developing area so I understand that as well, and I appreciate your giving it consideration. Thank you.

MR. SIMPSON: Are there any other questions for this panel during the public section of today's conference? Okay, I think then what we're going to do is we are going to shift to NextEra witness Stephen Whitley. And to be clear, we're going to do public questions for Mr. Whitley. Then we're going to shift to the confidential section of the conference today, and I think we'll go -- since Mr. Whitley will already be up there, we'll do confidential questions for him. Then we'll bring the LEI folks back for confidential questions for them. If my estimates, and I've been keeping a running total going, if they're correct, we are in the ballpark for finishing at a reasonable time today. So let's shift gears to Mr. Whitley right now.

MS. FRAYER: Chris, could we have a -- I just wanted to make sure, just for the sake of economic efficiency, we were thinking that if there's truly no questions for Marie Fagan, we could have her try her long commute back home a little bit

earlier.

MR. SIMPSON: So thank you. I'm fine for that. I want to get confirmation from everybody. Marie will not be available on the 19th. So if you have questions for her, this is the time. Based on what we heard earlier, there are no more public questions and no confidential questions. Is that correct? Okay, Marie, thanks. Drive carefully.

MS. FAGAN: Thank you.

MR. SIMPSON: Now that you've sat down, will you stand back up? Sorry about that. Do you swear or affirm the testimony you're about to give is wholly truthful?

MR. WHITLEY: I do.

MR. SIMPSON: Thank you. Jared?

MR. DES ROSIERS: Good afternoon, Mr. Whitley. My name is Jared des Rosiers, and I'll be questioning you on behalf of Central Maine Power. Do you have your testimony, direct testimony, handy? Because I've got some questions on it.

MR. WHITLEY: Okay. Go ahead.

MR. DES ROSIERS: On page six, and it's lines seven and eight. And the -- what I'm interested is actually lines eight and nine that discuss CMP is requesting a CPCN for an HVDC transmission line that has at least a 40-year life with only the prospect of market usefulness of the project for 15 to 20 years. Could you explain what you mean by the clause at the

end of the sentence with "only the prospect of market usefulness of the project for 15 to 20 years"?

MR. WHITLEY: Well, as I understand it, the contractual arrangement for power flowing on the project go out 15 to 20 years and, after that, there's no guarantee of what might happen. And, you know, it is a DC line. It's very limited in flexibility of things it can do like integration of other resources. So if conditions change beyond the 20-year period where the power may be more useful to Canada than it is to the U.S., then the project would not be as useful. And so I think in my colleague Chris's comments, he talks about a market cliff, and I think that's what he's talking about. There's no certainty of what might be -- the project might be used for beyond that period as opposed to, if it were an AC network expansion, you would have a free-flowing interconnection that could be used for lots of other purposes in this timeframe.

MR. DES ROSIERS: Do you have an understanding of what the business arrangements would be with respect to the transmission capacity on the line over the first 20 years or thereafter?

MR. WHITLEY: I do not.

MR. DES ROSIERS: And you -- on the same page in line 11, you used the term, "There is a cliff on those needs and benefits once the PPA expires." And then it drops down to a footnote, and I know there's been a number of data requests

about what we're meaning by a cliff. But could you explain how the -- as I understand it, the term of the PPA then defines the edge of the cliff, is that the right way to think about it?

MR. WHITLEY: That's the way I was thinking about it, yes.

MR. DES ROSIERS: And then under your -- if I'm understanding this that when the PPA -- and say it's 20 years and I will let you know it is 20 years so we'll talk about it in terms of 20 years. But if it's 20 years, why is it that the benefits go away for customers?

MR. WHITLEY: Well, there's no certainty of what might happen beyond the 20 years as conditions change. Demand may increase in Canada beyond the point where they need the power more for Canada than they need to sell it. And therefore, there's no certainty of how the project may be used beyond the contractual period?

MR. DES ROSIERS: And do you have any judgment or opinion as to whether New England states will no longer have a demand or the demand for clean energy will go down 20 years hence?

MR. WHITLEY: I really don't have any detailed knowledge of that. I just know that demand is slowing all over the Northeast and the whole country demand is slowing. Renewables internal to the U.S. are growing, and I think the needs may be lesser as you go out in time because the amount of

renewables that are growing in this country and in New England, for example.

MR. DES ROSIERS: Well, let's test that a little bit. So instead of the NECEC delivering 1,090 or 1,200 megawatts of hydropower from Quebec an AC line were built in western Maine to deliver, say, 1,200 megawatts of wind or solar, is it your view that there would still be a market for that clean energy in 20 years but not necessarily a market for Hydro-Québec's hydropower?

MR. WHITLEY: I'm saying a lot of conditions could change, including the demand in Canada that may make the need for that hydropower that's surplus in Canada today not so surplus going out in the future.

MR. DES ROSIERS: And if Massachusetts were to enter -- instead of entering a 20-year power purchase agreement for clean energy from Hydro-Québec, it entered 20-year power purchase agreements from developers of renewable projects in western Maine, would there also be, under your view, the same cliff potential?

MR. WHITLEY: Well, I think the resources would be more internal to the footprint. Probably would not go away. Probably would be -- continue to be dispatched into the system in New England. Some may sell outside through AC to Canada but most likely would be used internal to New England. But it's just a judgment. You know, when you look out that far in the

future, lots of things can change. Previous speakers already talked about resources in New England, you know, retiring, nuclear plants not being here much longer. So a lot of things can change.

MR. DES ROSIERS: Are you suggesting that the hydro facilities that Hydro-Québec operates are going away in 20 years?

MR. WHITLEY: Most likely not going away. I see the hydro facilities being there a long time.

MR. DES ROSIERS: And in your -- do you have an understanding of the concept of a participant-funded transmission line?

MR. WHITLEY: Yes.

MR. DES ROSIERS: What is your understanding of that concept?

MR. WHITLEY: A participant-funded transmission line would be one that the market participants funds for their benefits and they pay the costs and the costs aren't rolled into the rest of the pool like --

MR. DES ROSIERS: Is it your understanding that the NECEC is being structured as a participant-funded line?

MR. WHITLEY: Yes, through a contract.

MR. DES ROSIERS: And is it your understanding that the participants funding this line are both the electric distribution companies of Massachusetts and Hydro-Québec?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And do you know -- do you have an understanding as to who has the transmission rights to use the NECEC line?

MR. WHITLEY: Would be the participants.

MR. DES ROSIERS: And that would be for the duration of the contracts?

MR. WHITLEY: Yes.

MR. DES ROSIERS: Now, with respect to your concern about a cliff after 20 years, do you have an understanding as to HQ is purchasing transmission rights on the NECEC for years 21 to 40 for the full capacity, 1,200 megawatts?

MR. WHITLEY: I did not know that.

MR. DES ROSIERS: Well, if you assume for purposes of my question that in years 1 to 20 Massachusetts is purchasing 1,090 megawatts of capacity on the line and Hydro-Québec is purchasing 110 megawatts of capacity on the line for years 1 to 20 and then in years 21 to 40 Hydro-Québec is purchasing the full 1,200 megawatts of transmission capacity on the line, does that in any way impact your judgment that there is some kind of a cliff that would make the benefits go away.

MR. WHITLEY: I would say that's still not a guarantee that the power would flow into New England through that period, but it's an indication that they see a long-term market opportunity.

MR. DES ROSIERS: Because in that instance, they -- Hydro-Québec would be paying significant dollars for those rights?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And what is the obligation, if Hydro-Québec or Massachusetts didn't make use of the rights during the term of the transmission agreement, they were excess and they weren't using them, do they have an obligation to make them available in the marketplace?

MR. WHITLEY: The transmission capacity?

MR. DES ROSIERS: Correct.

MR. WHITLEY: I believe so.

MR. DES ROSIERS: And that's done through a public posting on an OASIS site for other generators to use?

MR. WHITLEY: I think that's correct.

MR. DES ROSIERS: And Mr. Whitley, do you have an understanding of what an elective transmission upgrade is under the ISO New England tariff?

MR. WHITLEY: I do.

MR. DES ROSIERS: And what is that?

MR. WHITLEY: I think that's when a new project is proposed that may not totally integrate into the system reliably. Elective upgrades are identified that the new asset owner may need to build to ensure reliability, and those projects are called electric upgrades.

MR. DES ROSIERS: And who pays for -- and in the parlance, I may use the phrase ETU because in ISO New England we've got RTUs, and we've got ETUs are elective transmission upgrades. But for an elective transmission upgrade, who pays for those upgrades?

MR. WHITLEY: The primary builder. Whoever's in the contractual arrangements there.

MR. DES ROSIERS: So the customers don't pay for ETUs?

MR. WHITLEY: Right, if they're all identified upfront.

MR. DES ROSIERS: And who has the rights to use -- transmission rights to use the ETU, elective transmission upgrade facilities?

MR. WHITLEY: I believe they become network assets, but I'm not positive on that in New England.

MR. DES ROSIERS: And is it your understanding that the NECEC is proposed as an elective transmission upgrade?

MR. WHITLEY: Yes.

MR. DES ROSIERS: Now if you turn to page eight in your testimony. And on line five there's a sentence, "HVDC technology is largely used for point-to-point electric power transfer injections over long distances, typically more than a few hundred miles." And in these instances where parties are moving electric power over a long distance, why do they use

HVDC?

MR. WHITLEY: It's cost effective. It has lesser problems as long-distance AC transmission does in terms of things like high voltage, harmonics, and other features, and it just turns out to be cost effective when you go really long distances.

MR. DES ROSIERS: And is there a difference with respect to line losses when you transmit large volumes of energy over a long distance using HVDC versus HVAC?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And what is that difference?

MR. WHITLEY: Typically get lower losses as opposed to long AC transmission lines. Certainly you get higher reactive losses on the AC lines, but you get high voltage -- and you get high voltage on AC lines.

MR. DES ROSIERS: And if, in this business arrangement, Massachusetts has chosen to purchase 1,090 of hydropower from the Quebec system in its -- and to most effectively move that power to deliver it to the New England system, would you agree that, all else being equal, HVDC is the more efficient way to move that power?

MR. WHITLEY: I agree that HVDC is a good way to get it to the border, but I think integrating it into New England would be better to have an AC network to receive it and integrate it robustly into New England. So that's an

alternative in my testimony I mention I wish were looked at more closely.

MR. DES ROSIERS: In western Maine is there any transmission network today?

MR. WHITLEY: There is, but it's not very robust.

MR. DES ROSIERS: Is the HQ system synchronized with the New England system?

MR. WHITLEY: No. It's an asynchronous system. It's a separate interconnection with the eastern interconnection.

MR. DES ROSIERS: And for most of us here who are not -- haven't spent their lives as a transmission planning engineering and operating systems, what does that mean simply?

MR. WHITLEY: That means when they interconnect with another system besides themselves, they typically have to have a DC connection like they have with Sandy Pond, like they have with New York. And -- but, you know, sometimes it can be done a back-to-back DC conversion, you know, near the border as opposed to a long transmission line.

MR. DES ROSIERS: All right. If you ran an AC line from Lewiston, Maine and interconnected it into the AC substation somewhere in Quebec, what would happen?

MR. WHITLEY: Well, you would need to have a DC converter first to connect into their system.

MR. DES ROSIERS: So with your discussion then of AC versus DC, in all of the situations, there has to be DC

elements. The power in Quebec has to be converted from AC to DC and then reconverted to D -- excuse me, AC to be injected into the ISO New England system.

MR. WHITLEY: That's what the converter does is reconnect the system with two different frequencies, and then the AC would need to be integrated properly to allow the power to flow.

MR. DES ROSIERS: So then a lot of -- breaking your testimony down then, it comes down to the question of where you put the converter station to convert it back from DC to AC?

MR. WHITLEY: Right.

MR. DES ROSIERS: And it's either your suggestion, it could be back to back in Quebec or -- whether that's at a substation, or it could be at the border?

MR. WHITLEY: Yeah. The way I see it, with my experience in this area, if it were back to back in Canada and then the AC network as built up there down there to make a robust connection into Maine and down into southern -- into New England, you would have a more robust connection for it much like you have at Sandy Pond and power could flow into New England and other resources in Maine, for example, could integrate into the network. The way this is proposed is sort of a one-supplier-only project, and the DC part of it coming into Maine really is bottling out other resources to get on the grid. And I like to -- I know this sounds hard, but I like to

categorize it like it's an interstate highway going into a two-car garage. So if the network were expanded in a robust manner into New England to make it more deliverable with more headroom, then it would be a much better project.

MR. DES ROSIERS: Fair enough. Massachusetts has chosen, and today contracted for, 1,090 megawatts from Hydro-Québec. That's what Massachusetts has agreed to pay for. Sounds like, under your testimony, that you're advocating for more transmission. There would have to be a network built in western Maine that would be sufficiently capable to not only deliver this 1,200 but deliver some additional resource beyond the 1,200.

MR. WHITLEY: I think that there's -- once this project -- if the project were built as proposed, I think -- and these electric upgrades get built as proposed, based on what's proposed, we really don't know all the answers of what's needed because we're waiting on an ISO New England study that doesn't come in till first quarter of 2019 which may have some other projects that need to be built. But once that would be built, I think that sets up a new sort of condition for the network where you have a lot of this generation, this hydro generation injected into Maine into a network that can handle it but has almost no headroom. I think anything else that happens, the next five to ten years or sooner with retirements, changes in demand, and so forth are going to leave for more

connections to be built. And I think ultimately, a more robust network would be built to get power further down into New England. I really do. That's my judgment. And if you look at the other connections of DC into New England, you've seen that happen. And you have a much more robust network to receive that power and move it in different directions. And with all that's going on in the marketplace with retirements and changes in demand and so forth and integration of more renewables, I think that's just going to happen.

MR. DES ROSIERS: And when you say a network, I'm thinking about western Maine. And under what I just understood you described, if we position a converter station in BD Township on the U.S. side of the border or right across the border in Quebec and then it's, at first, an AC line from the converter station to the Larrabee Road substation in Lewiston, would -- and it is sized to transmit 1,200 megawatts which is what the size of the NECEC is, would any other generator who was seeking to develop a project in western Maine be permitted by ISO to interconnect into that line?

MR. WHITLEY: If that used up all the headroom, no. It would require possible other upgrades depending on the configuration.

MR. DES ROSIERS: So even if it was AC, there would have to be additional transmission facilities built in western Maine to facilitate the development of that renewable resource?

MR. WHITLEY: It depends on the location of all these different resources and what happened. There'd be risk in both areas.

MR. DES ROSIERS: And on page 11 of your testimony, in lines 17 to 20, you're talking about the HVDC phase two project. Do you see that?

MR. WHITLEY: On page what?

MR. DES ROSIERS: Page 11.

MR. WHITLEY: Oh, 11, I'm sorry. Eighteen through 20? Yes.

MR. DES ROSIERS: And do you recall when the phase two project was constructed?

MR. WHITLEY: It's before my time, but I happen to know some engineers who worked on the project and know them quite well. And I think it was planned and built sometime in the mid to late 80s, somewhere around '86 or so.

MR. DES ROSIERS: And is it still in operation?

MR. WHITLEY: Yes, it is.

MR. DES ROSIERS: Now your point is here that the HVDC phase two is underutilized and that only 441 megawatts of firm capacity is committed over the line. What do you mean by that?

MR. WHITLEY: Well, I'm not sure about that number. Let me follow up on that. But I know the tie is good for 2,000 megawatts and no more than, I think, 1,400 can be scheduled on

it. This may be a contractual number, I'm not sure. I'll have to --

MR. DES ROSIERS: Do you know what the flows have been on that line for the last several years?

MR. WHITLEY: My history of being the COO of New England, it pretty much had been operated up to the max most of the hours except a lot of times in the winter when power would sometimes be reduced and go back the other way.

MR. DES ROSIERS: And do you have any reason to believe that with the addition of the NECEC, that the flows on the phase two line would change?

MR. WHITLEY: No.

MR. DES ROSIERS: And do you have any reason to believe that Hydro-Québec does not have the generation capacity to continue to flow power on a -- on the phase two line consistent with its past practice and deliver 1,090 megawatts on the NECEC?

MR. WHITLEY: No, nothing other than what I mentioned earlier, that things change when you get down in time. Their demand continues to grow. Their -- the way I understand the way they market their power, they market to the highest price once they have the infrastructure to move the power. And -- but over time, their load is going to grow and that more of the capacity will be dedicated to their internal growth.

MR. DES ROSIERS: And do you have any sense from your

experience at ISO or experience at New York ISO as to the relative prices between the New England market and the New York market and the Ontario markets?

MR. WHITLEY: Yeah, I have a sense of the difference.

MR. DES ROSIERS: And what is that sense today, recognizing --

MR. WHITLEY: Well, the sense is that most of the hours of the year prices are very close to the same because the price is set by natural gas. And during the off-peak periods, the prices get very low in Ontario because they have such a surplus of wind and so forth and nuclear. And in Hydro-Québec, they've scheduled to where the higher price is. That's how they move.

MR. DES ROSIERS: And is it your experience that when prices are really low in Ontario, Hydro-Québec may actually buy power and import it into Quebec rather than export?

MR. WHITLEY: That's correct. And they may actually have to pay to take it.

MR. DES ROSIERS: And that doesn't lead to fossil coal or oil or gas plants being turned on in Ontario, does it?

MR. WHITLEY: I can't answer that. I think some more modeling would have to be done on a broader region, but I think the -- my understanding of where the power flows, it's flowing where the prices are. And, you know, through the AC network, the higher prices may be in PJM with the coal systems over

there, and they may be getting power through Ontario to them which I'm pretty familiar that happens. And when power gets diverted from this, you know, low-cost hydro resourcing in Canada, it may be going to that area ultimately as opposed to New York or Ontario.

MR. DES ROSIERS: Now if we go back to your concept you make the NECEC an AC line -- let me actually stop there. What is -- if you go to page 14 in your testimony, on lines nine and ten there's a reference to a concept of a loss of source contingency for ISO New England. And the sentence is, "Although it does not appear that the HVDC transmission line creates a new limiting loss-of-source contingency for ISO New England." What is a loss-of-source contingency?

MR. WHITLEY: Well, loss of a single source, like the loss of a nuclear plant in New England. When that happens, you have an instantaneous response from all the other generators in the eastern interconnection to move power where that whole is created. And in New England, because that power comes across New York and there are some limited connections and you can get voltage collapse, studies are always done to determine how much that maximum can be. And I think today, that maximum can be about 1,400 megawatts, and that's the reason you can't schedule more than about 1,400 megawatts across phase two. So that's what -- and it's an extremely important reliability consideration that's looked at very closely over time and re-

looked at and re-looked at, and -- because the consequences of having a loss-of-source contingency that might be greater than causing a blackout, it's a very serious issue.

MR. DES ROSIERS: Now I've-- in a -- I'm looking at a document called the Transmission Planning Technical Guide from ISO New England, and it refers to this loss-of-source contingency, and there's a sentence. "The low limit of" -- or let me read it. "The maximum loss of source for a normal design contingency has been jointly agreed upon by New York ISO, ISO New England, and PJM to be between 1,200 megawatts and 2,200 megawatts depending on system conditions within New York ISO and PJM. This practice is observed pursuant to a joint FERC-approved protocol which is Attachment G to the ISO tariff. The low limit of 1,200 megawatts has historically been used for design contingencies in New England." And do you recall that New England uses the low end of that limit, 1,200?

MR. WHITLEY: I thought it was 1,400, but it may be still 1,200.

MR. DES ROSIERS: And just for purposes, and you can take this subject to check, if it is 1,200 in New England and the NECEC is designed for 1,200 megawatts and the contracts are that HQ can deliver 1,200 megawatts on a line, does that mean that no more source -- ISO won't allow any more generation to be added -- capacity to be added to that line for the potential that it would exceed that loss of source?

MR. WHITLEY: The single source on that line, yes. Now there's an additional risk that I point out in my testimony. It's an unlikely contingency, but it did happen a few years back. When I was at New York, there was a condition in Canada that was a forest fire between the hydro resources and the load. That's a lot of miles there with a lot of exposure, and because basically the policy in Canada is let the fires burn until they go out, that smoke got involved in transmission lines and caused a simultaneous trip of the connection into New York and New England. That happened on an off-peak day and so it didn't cause a big problem, but it was serious concern. And so there's some risk that this is a third DC tie coming down into the northeast. If a condition like that happened again -- you know, probability of it's probably low, but it's something that has happened and could happen again. So that poses an additional risk.

MR. DES ROSIERS: Well, and that risk doesn't change if the NECEC is an HVDC line or HVAC line?

MR. WHITLEY: The only difference, though, if it were an AC line into Maine, there would be more opportunities for other resources in Maine to integrate into that network and get to the load which might lessen the --

MR. DES ROSIERS: Well, again, when it's just a single 1,200-megawatt line, there's nobody interconnecting if I understand your prior testimony.

MR. WHITLEY: If all three of them were loaded up to the maximum amount, yeah, it would -- the risk would be the same.

MR. DES ROSIERS: And thinking in terms of planning criteria -- and I appreciate the -- there's a contingency that the Quebec system can fail. That's what you've described. Is that a contingency that planners would include in a planning model?

MR. WHITLEY: It's not what I would call a hardline contingency that goes and justifies new transmission, but it's something that they should look at to see how the system could handle it. It's what I would -- we used to call those extreme contingencies, and -- but they are important to look at in this case because New England is out here sort of the end of the system and the only way for power to get here is across New York. It's something that's very important.

MR. DES ROSIERS: In thinking about that kind of planning criteria, if New England is relying on phase two and receiving -- you know, it's fully loaded in many hours of the year, from a planning perspective, would it be good to have another tie from Quebec for -- to cover the contingency of the loss of phase two?

MR. WHITLEY: Sure, sure.

MR. DES ROSIERS: Now on page 13 of your testimony. Oops, I skipped one so just back up one page. On lines four to

eight you talk about the construction of an HVAC double-circuit tower line as one option. And I just make sure I want to -- make sure I understand the concept. That would be -- you know, we locate the converter station somewhere up near the border. We build an AC line from there down to Lewiston. But knowing that we're going to need a -- if there is further development there, we'd have to, you know, add another line so we build the current NECEC with towers that are sufficient to be double circuit. And as I understand that, that's big enough -- a tower that's big enough to have two sets of 345 lines on the same tower structure.

MR. WHITLEY: Correct.

MR. DES ROSIERS: Those are pretty big structures?

MR. WHITLEY: They are, but in my judgment, that's been used in New York at TVA where I worked and it's proved out to be very wise as a long-term planning way to go because it's so much easier to expand later on and much more flexible.

MR. DES ROSIERS: Are there planning criteria that ISO has or NPCC has with respect to double-circuit towers?

MR. WHITLEY: Yes, you always have to study the system to make sure that the loss of both circuits will not cause an overload or a stability problem.

MR. DES ROSIERS: And in reaching this suggestion that NECEC be designed in a double-circuit way, did you factor in any consideration of the permitting aspects of permitting

those larger structures?

MR. WHITLEY: No.

MR. DES ROSIERS: Did you consider the difference in cost -- you would agree that the double-circuit towers would be more costly?

MR. WHITLEY: Would be incrementally more costly but in the long term be much less costly.

MR. DES ROSIERS: And in your construct, who would pay the incremental cost?

MR. WHITLEY: Well, the way it could be set up, that the initial supplier builds the basic structure in the first circuit, and any future expansion that comes along is paid for by the new developers. That's one concept.

MR. DES ROSIERS: So in this context, I just want to understand, CMP should go to the participants who are funding the line, Massachusetts customers and Hydro-Québec, and say you should pay more to build this as a bigger structure so that it will, in the future, potentially facilitate the development of other generation in western Maine?

MR. WHITLEY: I'm not sure it would be paying more. It may be paying less than what this project actually cost when all the studies are done. It may be less.

MR. DES ROSIERS: Well, let's explore that a little bit. The project -- we need two converter stations in any case?

MR. WHITLEY: Right.

MR. DES ROSIERS: And we need transmission line that runs from the Quebec border to Lewiston, Maine, correct?

MR. WHITLEY: Right.

MR. DES ROSIERS: And do you have an understanding that the DC line that CMP is proposing is overhead construction?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And do you have any understanding as to the relative cost of building a DC overhead line versus building a 345 kV AC overhead line?

MR. WHITLEY: Approximate. I don't have detailed knowledge of the DC cost, but I have a pretty good knowledge of the AC cost.

MR. DES ROSIERS: And is there any reason to believe that overhead DC is any more costly than overhead AC? Talking about the line; we're not talking about the converter station.

MR. WHITLEY: No.

MR. DES ROSIERS: But building a double-circuit tower, you'd agree that's more costly than building --

MR. WHITLEY: A single-circuit tower, yes.

MR. DES ROSIERS: And have you considered in your testimony at all the ramifications for building a double-circuit tower crossing the Kennebec River gorge?

MR. WHITLEY: No.

MR. DES ROSIERS: I'm going to turn to page 15. I'm looking at lines 15 to 20. And it refers to -- or there's a clause, "It is likely that the next incremental utility scale generation project interconnecting into the Maine system will likely have to build a duplicative AC transmission line to get to the ISO node which could result in considerable system upgrades that would be paid for, in part, by ISO New England customers and Maine." You see that?

MR. WHITLEY: Yes.

MR. DES ROSIERS: I want to test first the -- assume there is no NECEC.

MR. WHITLEY: Yes.

MR. DES ROSIERS: Not an assumption that I personally like, but let's assume it. And there are projects in western Maine, renewable projects, that want to be built. Who -- they would require transmission upgrades to be interconnected at an ISO node.

MR. WHITLEY: Right.

MR. DES ROSIERS: And who would be responsible for the cost of those upgrades?

MR. WHITLEY: The developers.

MR. DES ROSIERS: So your client NextEra desires to build wind farms or solar projects in western Maine, it would have to bear the cost of building those facilities to get to an ISO node, Lewiston, Maine Larrabee Road substation.

MR. WHITLEY: Right.

MR. DES ROSIERS: And there's nothing about the NECEC alone that, you know -- they would be -- leave aside NECEC, they have to bear those costs. Now, at the end of this sentence, there's a part that suggests that part could be paid, in part, by ISO customers in Maine. And I want to understand, first, in the scenario where there is no NECEC but the renewable generation projects in western Maine move forward, what is, if any, circumstance that customers anywhere in New England or in Maine would have to pay for any portion of those upgrades?

MR. WHITLEY: Well, if any of the -- there's other mechanisms for allocation of cost for transmission that could become a new base case condition as a retirement and a reliability issue comes up, and it could be a reliability project. It could be an order 1000 type project that comes along that could be borne among ratepayers. There's other mechanisms.

MR. DES ROSIERS: I appreciate that. I'm trying to think through the reliability upgrade situation where you're running a radial line from western Maine in to bring renewables and how that ever fixes a -- let me strike that. You are bringing a -- building a radial line from western Maine that brings -- to deliver intermittent resource, how that could ever solve a reliability issue.

MR. WHITLEY: Well, if network conditions change, and so that, with those resources in the mix, and let's say there's retirements elsewhere that require a reliability upgrade downstream, there may be a need for an upgrade.

MR. DES ROSIERS: So now in the situation where NECEC is built either as a DC line or as an AC line and it's fully loaded at 1,200 megawatts by HQ and along comes NextEra or another renewable developer seeking to develop projects in western Maine, who bears the cost of those upgrades? To allow the interconnection of that new generation to the ISO system?

MR. WHITLEY: The new suppliers.

MR. DES ROSIERS: And if you turn to page 16? There's -- in the page 16, lines 22 through 22, there's a sentence, "Also, the commercial viability of the transmission line would be enhanced by the ability of Maine-based renewables to interconnect to the line." Could you explain that sentence?

MR. WHITLEY: This is really getting back at the point of AC versus DC. A DC line is the -- is really great for point-to-point transmission, but it's not very expandable. You know, if it runs through your region here and if you have other resources that need to get integrated in the grid, you just can't run out and interconnect with a DC tie. It's extremely prohibitive and expensive. If this were AC and the network were upgraded in a robust fashion to integrate this power through Maine on AC, it would actually open up more competition

for use of those facilities, you know, for the grid. And this -- DC, designed the way it is, it's kind of doing the opposite thing. It's great for this one supplier, but it's not offering, you know, opportunity for other options. It may be beneficial down the road.

MR. DES ROSIERS: Sorry, let me test that a little bit. We've -- I think we've agreed that if the line is fully loaded at 1,200 megawatts, the -- they -- this new generation couldn't just interconnect in the line. So there'd have to be other facilities built. And am I to understand then that if we built the network in western Maine so there was a sort of a loop, a 345 loop, running in that rea, in that world then, having that would then facilitate further interconnections of other renewable generation?

MR. WHITLEY: Right.

MR. DES ROSIERS: And in that world, somebody has now paid for a 345 kV loop in western Maine?

MR. WHITLEY: Well, to integrate the network, but it offers a lot more options for the future.

MR. DES ROSIERS: So now I'm going to turn to a few of your data requests -- data responses.

MR. WHITLEY: Okay.

MR. DES ROSIERS: Chris, we're going to do all the public and then have a short confidential session.

MR. SIMPSON: Okay, that works.

MR. DES ROSIERS: Could you turn to the response to CMP 01-11?

MR. WHITLEY: Okay.

MR. DES ROSIERS: And --

MR. WHITLEY: 14 May?

MR. DES ROSIERS: What's that?

MR. WHITLEY: 14 May?

MR. DES ROSIERS: Correct. The question says, "Please identify the scenarios or circumstances in which you would support the construction of an HVDC line rather than an HVAC line." And the answer, after the objection, gets to see pages 21 to -- or excuse me, 4 through 21 of your testimony. And I've read that a few times, and it's -- it advocates well for an HVAC line but not an HVDC line. So I really just want to repeat the question. Are there any circumstances in your experience and professional judgment where you would advocate for a DC line in this circumstance bringing power from Quebec to New England?

MR. WHITLEY: I want to point out I'm not a DC line hater. You know, I think DC has its place, and there would be a DC line in this proposal if the Maine part were AC. But generally when you have an opportunity to put a long line like this underwater, DC is wonderful. It's very efficient to do that. We have interconnections in New York that were done that way. They make a lot of sense. So those are some examples.

MR. DES ROSIERS: And are you -- you're familiar -- are you familiar with the project called the -- that was sponsored by TDI to build a DC line under Lake Champlain to serve New England?

MR. WHITLEY: Yes. Not detailed but just observed it, yes.

MR. DES ROSIERS: And is it fair to say that a buried DC line is more expensive than an overhead line?

MR. WHITLEY: Absolutely. But if it goes in the water, like down the Hudson River, it makes a lot of sense.

MR. DES ROSIERS: And I'm just imagining trying to run the line down the Kennebec River, and it'll -- I think there'll be issues. The -- let's see, I'm trying to figure out which ones are confidential.

MR. WHITLEY: And I want to mention also if the studies show that the DC line were the most cost-effective approach, I certainly would support it. It'll solve the engineering problems and was the most cost effective.

MR. DES ROSIERS: And if you could turn to CMP 01-010.

MR. WHITLEY: Okay.

MR. DES ROSIERS: And in this response, about two-thirds of the way down, it says, "In 2017 ISO New England reported zero congestion for a major transmission interface in Maine called Surowiec South. Production cost simulations based

on a commercially-available software confirmed this when the NECEC was not in service. The same production cost simulation but assuming the NECEC was in operation in 2017 revealed that about 76 percent of the time this transmission would be congested annually. While the congestion increased, local wind farm production was curtailed by up to 42 percent." And what is -- could you tell me what -- about this production cost simulation and who ran it and when was it done and --

MR. WHITLEY: I had some assets available to me through NextEra and their staff to run a production cost model called GridView that has a transmission network model and all the constraints modeled. And using the basic modeling assumptions similar to the ISO New England Maine resource integration study, we modeled the network with and without MEC (phonetic) in there and found these differences in congestion and also in wind curtailment.

MR. DES ROSIERS: And do you know who ran this model?

MR. WHITLEY: Pardon?

MR. DES ROSIERS: Do you know who ran the model?

MR. WHITLEY: I believe it's an ABB model called GridView.

MR. DES ROSIERS: And I'm assuming that you weren't the one sitting at the keyboard running the model.

MR. WHITLEY: You have that a hundred percent right.

MR. DES ROSIERS: But do you know who actually

entered the model?

MR. WHITLEY: I do know who was responsible for running the model.

MR. DES ROSIERS: And who was that?

MR. WHITLEY: His name is Henry Chao.

MR. DES ROSIERS: And where is he located?

MR. WHITLEY: He is located in Albany, New York.

MR. DES ROSIERS: And he's an employee of NextEra?

MR. WHITLEY: No.

MR. DES ROSIERS: Then who does Mr. Chao work for?

MR. WHITLEY: He works for Quanta. He used to work for me.

MR. DES ROSIERS: And do you know what input assumptions were used in configuring this model?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And what -

MR. WHITLEY: They were -- they used information pretty much consistent with ISO New England's planning process in the Maine wind integration study. It's an hourly simulation model that models the network, dispatches the system on the most-economical manner. It takes into account the E4 rates of all the units in New England. And I've found over my years in planning it's a very -- pretty good tool to use for planning this kind of analysis.

MR. DES ROSIERS: And this refers to 2017? Did it

model 2017 conditions?

MR. WHITLEY: I believe it did, 2017 conditions.

MR. DES ROSIERS: And do you know -- you said it put NECEC -- now, first, do you know has this model been provided in this case?

MR. WHITLEY: No.

MR. DES ROSIERS: It has not?

MR. WHITLEY: No.

MR. DES ROSIERS: Do you know -- you said the --

MR. WHITLEY: I think we provided the table, you know, of the results.

MR. DES ROSIERS: We were going to ask about those because I wanted to know where they came from. So I'm assuming now they came from this modeling?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And the NECEC was added. What does that mean?

MR. WHITLEY: That means an injection of 1,200 megawatts was made in the model in accordance with the way the project is proposed.

MR. DES ROSIERS: Were there any adjustments made to -- what transfer limits were used at the Surowiec South?

MR. WHITLEY: I can't recall. I'll have to find that out for you.

MR. DES ROSIERS: And were -- to your knowledge, were

any updates made to the model to reflect the network upgrades that are part of the NECEC project?

MR. WHITLEY: I believe all of those were included in the model.

MR. DES ROSIERS: The -- and do you know what assumptions were made for load or did it just use 2017 actuals?

MR. WHITLEY: I'm not sure.

MR. DES ROSIERS: Now -- and I think a couple of these next ones were labeled as confidential because they -- and it was the workpapers that you attached to a couple of ODR -- or a couple of data responses, one of which is 01-01 and one of them is -- CMP 01-01 which asked for your workpapers. And then there were two pages that were attached. It seems like we're talking about the same thing that's not labeled confidential, but the pages to that data response --

MR. WHITLEY: Those tables?

MR. DES ROSIERS: The tables were listed as confidential.

MR. WHITLEY: The tables?

MR. DES ROSIERS: And I don't need to -- are they confidential?

MS. OLFENE: Yes.

MR. WHITLEY: Yes.

MR. DES ROSIERS: Okay. Well, I'm going to make an ODR request that you please provide the entire model and the

model outputs much as our friends LEI and our friends from Daymark have done so that we can review the model and the inputs.

MR. WHITLEY: I'll get with my attorneys and take that into account.

MR. SIMPSON: For the record, this is the fourth set of ODRs. So that'll be ODR 004-005.

MS. COOK: -- different set for a different --

MR. SIMPSON: Oh, yes, correct. So 5-1. Yeah, sorry, thanks.

MR. DES ROSIERS: So is it -- ODR 05-01 will be directed to Mr. Whitley?

MR. SIMPSON: Yes.

MR. DES ROSIERS: The five sets will be to Mr. Whitley? That's -- and to your knowledge, Mr. Whitley, work commissioned by NextEra specific for this case and they retained Quanta for this purpose?

MR. WHITLEY: That's my understanding, yes.

MR. DES ROSIERS: Now in -- and we don't have to look at the particular numbers. In the response, though, the tables that are produced as part of CMP 01-01 refer to a 2021 forecast. Do you know what that refers to?

MR. WHITLEY: No, I have to get back with you on that.

MR. DES ROSIERS: I just want to make sure as part of

the ODR, if there's a 2017 model and a 2021 model, that the ODR covers all of the modeling that was done by Quanta at the request of NextEra related to the NECEC and which you've offered some of the workpapers or some of the output results. Is that fair?

MR. WHITLEY: Yes.

MR. DES ROSIERS: Would these results that you have in your response with respect to -- well, let me strike (sic) this. Are you familiar with the capacity capability interconnection standard under the ISO tariff?

MR. WHITLEY: Yes.

MR. DES ROSIERS: And what is your understanding of that requirement?

MR. WHITLEY: You're talking about the I-3-9 standard?

MR. DES ROSIERS: No. Well, I'm actually talking about the capacity capability interconnection standard which is the one to qualify for the capacity market, the overlapping impact test they sometimes call it.

MR. WHITLEY: I'm not that familiar with that test.

MR. DES ROSIERS: Would -- if a project caused congestion 76 percent of the time, would ISO New England allow it to be interconnected?

MR. WHITLEY: I'm not positive, but I think they may. It depends on does it cause a reliability problem and a

degradation in the system network transfer capability and that the project -- you know, generation dispatch can be modified to back that off if it's a problem. So I'm not sure what they would do.

MR. DES ROSIERS: I want to turn to CMP 01-18.

MR. WHITLEY: 01?

MR. DES ROSIERS: 18.

MR. WHITLEY: Say again?

MR. DES ROSIERS: 18, CMP 01-18.

MR. WHITLEY: I'm not sure I have that one. Oh, yeah, I do. Got it.

MR. DES ROSIERS: And if I'm understanding, the concept here is, and then please correct me if I'm wrong, one of your suggestions was if there was a hydro unit in Quebec that was relatively close to the border so that it could connect to the AC version of the NECEC, whether that would be on the Quebec side of the border or on the U.S. side of the border, it could interconnect and then it could serve, really, as an AC -- as a generator part of the New England system as opposed to going through the Quebec system and having to be converted to DC and then back AC.

MR. WHITLEY: It may not be a hydro unit. It may be some other kinds of units also.

MR. DES ROSIERS: Are you familiar with any -- with the Quebec system and the location of their hydro generation?

MR. WHITLEY: Definitely of their hydro generation but not all of their other generation.

MR. DES ROSIERS: Is there any hydro generation that HQ owns anywhere near the Maine border?

MR. WHITLEY: No. But there may be, you know, renewable resources, wind and so forth nearby.

MR. DES ROSIERS: This concept only works if -- you know, if you are semi-close so you could run a -- essentially a gen lead to this AC version of the NECEC?

MR. WHITLEY: Right. And as I -- I gave an example of how that's done in New York.

MR. DES ROSIERS: And to do 1,090 megawatts all hours, that's a pretty large hydro facility. And I'll represent to you that Massachusetts is buying hydropower so it's got to be from a hydro facility.

MR. WHITLEY: Okay.

MR. DES ROSIERS: You're not aware of any -- of HQ dams anywhere near the Maine border that could serve 1,090 megawatts, that's correct?

MR. WHITLEY: I'm not aware of any, no.

MR. DES ROSIERS: If you could turn -- I lost it. It's IECG 06-43. And with due respect to Mr. -- Drew, I'm going to ask one of his questions. That --

MR. WHITLEY: So it's 43, 6-43? Okay.

MR. DES ROSIERS: And this data request asks you who

assisted you in preparing your testimony, and it says you prepared your testimony, and "If I needed information from NEER, I obtained it from NEER's in-house counsel." That's NextEra?

MR. WHITLEY: Yes.

MR. DES ROSIERS: What information did you ask for from NextEra's counsel, in-house counsel?

MR. WHITLEY: Result -- a lot of testimony information, background on the project, some documents from New England on some of the studies I had done, they pulled all that together for me.

MR. DES ROSIERS: This answer doesn't make reference to your former colleague who's the modeler at Quanta?

MR. WHITLEY: Right.

MR. DES ROSIERS: Did you not speak with him about this testimony?

MR. WHITLEY: I spoke mainly through my counsel at NextEra. I spoke to that person asking some questions periodically.

MR. DES ROSIERS: Did -- in the information you asked for, did you ask for any information about the renewable projects that NextEra is proposing to develop in western Maine that would be these renewable processes that would interconnect to the generation -- or the transmission network you've described?

MR. WHITLEY: Yes.

MR. DES ROSIERS: What information did you learn about those projects?

MR. WHITLEY: They provided me a list of projects that were in the queue and so forth.

MR. DES ROSIERS: Did they share with you whether those projects have any power purchase agreements or contracts in place that would actually fund and finance the projects?

MR. WHITLEY: Did not, no.

MR. DES ROSIERS: Did you ask for that information?

MR. WHITLEY: No.

MR. DES ROSIERS: From your experience, for a renewable wind project or solar project to be developed, is it necessary to have a power purchase agreement?

MR. WHITLEY: No.

MR. DES ROSIERS: Are you aware of any wind or solar projects of grid scale size built in New England that have been done without a power purchase agreement?

MR. WHITLEY: No, I'm not familiar of how they've developed in New England. More with New York.

MR. DES ROSIERS: And then if you could just turn to IECG 49. Do you have that in front of you?

MR. WHITLEY: Yes.

MR. DES ROSIERS: In here, in the second line -- the answer is, "The primary factors that keep Maine from being

robust or tightly integrated with its neighboring transmission systems include its system topology and the willingness or, rather, lack thereof of customers to pay for additional transmission infrastructure." And I'm interested in the parenthetical. What do you mean by or rather their lack thereof of willingness to pay for transmission?

MR. WHITLEY: Well, it's not just Maine, it's everywhere that transmission is built to a minimum standard. And in Maine, we ended up with -- when the markets were created in New England, we had a single price for power throughout the region. And the generators that were locating at the time tend to locate near the interconnection of a gas pipeline and transmission where it was easy to get that done. And so we ended up with a surplus of new generation in Maine and Sima (phonetic), Rhode Island. And so -- and the tariff and so forth, the planning process, prescribe a way to justify reliability projects, and the minimum number of projects have been built. A really good project was built in Maine not too long ago called the Maine reliability project that really helped. But in fact, the system is a pretty limited -- I would call it not a robust network in Maine as opposed to other parts of the region where you have a lot of interconnected 345 kV that can move power in either direction and has a lot more flexibility. So I think Maine's topology, the way generation initially located, where the low centers are relative to the

resources make it a very skinny, sort of less-robust network. And that's the way I would describe it. I think it's been improved, but it's certainly not a robust network. And if you look over at Sandy Pond, where that integrates into New England, it integrates into a much more robust network where power can be moved easily. That's why I think there's some risk here with this project as proposed. I think it's going to lead -- more upgrades will come. And it's just -- and I think all the studies need to be done first before a decision is made to see, you know, what are all the costs, what's the results of the New England study. But then even after that, I think, because it's leaving the system in a state of a heavily-loaded system, you know, most of the hours of the year, as conditions change, I think more transmission's going to be made.

MR. DES ROSIERS: The --

MR. WHITLEY: My judgment.

MR. DES ROSIERS: Do you have an understanding as to whether Central Maine Power has agreed to pay for all of the network upgrades that are identified as needed by ISO New England to permit the interconnection of the NECEC?

MR. WHITLEY: I'm not familiar with that agreement, no.

MR. DES ROSIERS: And is it -- I took your parenthetical to mean that customers in Maine, probably customers all over New England, don't want to pay for more

transmission than they need.

MR. WHITLEY: That's true, everywhere.

MR. DES ROSIERS: And in this context, are you aware of any customers anywhere in New England who would be prepared to pay for a transmission network in western Maine sized sufficiently to allow the delivery of 1,200 megawatts of power from Quebec and the future development of some undefined quantity of renewable generation, solar, wind, that could be developed in Maine?

MR. WHITLEY: Well, I think if the studies were completed to look at that alternative fairly with the currently -- the alternative that's proposed and that were a lower-cost alternative, it may very well gain support within the region.

MR. DES ROSIERS: That's all I have. Thank you.

MR. SIMPSON: Thank you. Well, I'm just about to check in with Toby. I'm going to give you your choice. We can either take a break now or, based on estimates, we have about 25 minutes to finish with this witness with all the public testimony. I know we've been going of an hour and 35 minutes. Would you like to break now?

COURT REPORTER: (No audible reply.)

MR. SIMPSON: Okay.

MR. TANNENBAUM: (Indiscernible).

MR. SIMPSON: Yeah, go ahead.

MR. TANNENBAUM: Good afternoon, Mr. Whitley. I just

have one question to -- maybe it's clear from your testimony. If the project was an AC, HVAC, line, would it be your recommendation to this Commission that it approve the project?

MR. WHITLEY: I don't know what, you know, your powers are to approve or not approve, but if it turned out that were the lowest-cost alternative and it met these technical requirements and had this expanded flexibility, which I think it does, I would certainly hope the Commission would support that.

MR. TANNENBAUM: Okay. Thank you.

MR. SIMPSON: All right, let's take a break. We'll come back at 20 after. We have about 25 minutes of estimates for this witness in public session, and then we will go into confidential session at that time.

MR. DES ROSIERS: Chris, I can --

MR. SIMPSON: Go ahead.

MR. DES ROSIERS: I've covered all my confidential questions without going there. So I don't believe I'll have any.

MR. SIMPSON: All right, that's helpful. Thanks.

MR. LANDRY: And I'll say --

MR. SIMPSON: Drew?

MR. LANDRY: -- Jared covered quite a bit of the material I had. So I probably have half of -- if that, of what I had for him.

MR. SIMPSON: Okay, okay. I still want to take a break now.

MR. LANDRY: Sure, that's fine.

MR. SIMPSON: And so come back at 20 after. Thank you.

CONFERENCE RECESSED (June 14, 2018, 3:05 p.m.)

CONFERENCE RESUMED (June 14, 2018, 3:20 p.m.)

MR. SIMPSON: All right, let's go back on the record. According to my notes, CLF is up.

MS. GREEN: Thanks, Chris. Our questions were addressed in the previous questioning.

MR. SIMPSON: Do you have any confidential questions for this witness or were those answered as well?

MR. TURNER: Yes, those were answered as well.

MR. SIMPSON: Okay, great, thank you. All right, let's go to the IECG.

MR. LANDRY: Okay. As I said, Jared covered quite a bit of what I had as well, but I do still have some remaining and some are almost as follow ups. Good afternoon. I'm Andrew Landry. I'm counsel for Industrial Energy Consumer Group. Before -- I'll get into some questions that are along the lines -- same line as where Mr. des Rosiers was -- I had wondered had you done any work as a consultant for NextEra or any other party in connection with Northern Pass transmission project, either supporting it or opposing it?

MR. WHITLEY: No.

MR. LANDRY: Okay, thank you. Now, let's see. I'll turn your attention to your response to IECG data request number six, item 37. I should probably pull the actual question. There's just my notes there. But if I can paraphrase, is it fair to say you state that you have no opinion on whether New England is -- has any need for Hydro-Québec power 15 to 20 years after 2022, is that --

MR. WHITLEY: That's correct.

MR. LANDRY: So when you say that -- I believe Mr. des Rosiers asked you a little bit about this -- that the project only has the prospect of market usefulness for 15 to 20 years, you really aren't stating any opinion about whether there is or is not any likely demand past the useful -- or the initial term of the NECEC contract.

MR. WHITLEY: That's correct. I think the project could be -- when it gets into those out years, it has a lot of uncertainty about how it might be used.

MR. LANDRY: Okay, thank you. You've been around the industry for a while, as have I, to be fair. Would you agree that Hydro-Québec has been actively seeking to expand its exports of electric generation into the U.S. and other provinces as an export business for many years?

MR. WHITLEY: Yes, and I've always seen it and they've explained it to me as a period of time where they have

surplus. They're building for the long term, ultimately for their native load. But while they have this surplus, they want to get into the high-price markets and make profit.

MR. LANDRY: Thank you. Do you have an opinion regarding whether Hydro-Québec has additional potential to develop renewable generating capacity or other large-scale generating capacity in the province beyond what's under -- what's already either under construction or in operation?

MR. WHITLEY: Don't have an opinion.

MR. LANDRY: Okay, thank you. You talked with Mr. des Rosiers a little bit about the concept of robustness. Is it your view that just the -- absent any other -- and the presence of NECEC or any other generation projects in western Maine, that the construction of a high-voltage AC line through western Maine would increase the robustness of Maine's transmission system?

MR. WHITLEY: It may require more than one line. It may be a few different upgrades that would make it robust so that you have parallel paths that could handle and give you more headroom than just zero headroom.

MR. LANDRY: Today there's no 345 line that goes north of -- I have to look at the -- are you aware -- are you familiar with the Maine transmission system?

MR. WHITLEY: Yes.

MR. LANDRY: And would you agree there is no 345 line

that --

MR. WHITLEY: In the western portion --

MR. LANDRY: -- western portion of the state?

MR. WHITLEY: Right, right.

MR. LANDRY: So this would be the first 345 line in that portion of the state if it were built?

MR. WHITLEY: Right.

MR. LANDRY: And you're saying to add robustness, we would probably have to create a loop with a second 345 line.

MR. WHITLEY: Or, you know, the double circuit idea proposed. There's other -- planners would have to take a good look at it, but there are some ways to do it that would add more expandability, more opportunity for additional applications in the future, and more headroom.

MR. LANDRY: Now if CMP were propose to build an AC line along the -- a single AC line into western Maine with no connection to Hydro-Québec, based on what you know, would you recommend to ISO New England that such a project ought to be approved as a reliability project?

MR. WHITLEY: I can't answer that one. I'd need to look at all the studies and -- give you an answer to that.

MR. LANDRY: Would you recommend to the Public Utilities Commission that it give it a certificate, such a line, as necessary for reliability?

MR. WHITLEY: Can't answer that.

MR. LANDRY: Or that Maine customers pay for such a line?

MR. WHITLEY: Need to see the studies.

MR. LANDRY: Okay, that's all I have.

MR. SIMPSON: All right, let's go to NRCM.

MS. ELY: Our questions were covered already.

MR. SIMPSON: Eric, you mentioned you may have some questions.

MR. BRYANT: Yeah, Jared asked one of mine. I have two left. Afternoon, Mr. Whitley.

MR. WHITLEY: Good afternoon.

MR. BRYANT: I'm Eric Bryant with the Maine Public Advocate. I represent ratepayers here in Maine. If you could turn to page 14 of your testimony. This is part of the section where you're talking about the line -- things would be better if this were an AC line, not a DC line. I'm looking at letter C which is lines three through eight. In that section of testimony, you testify that if it's a DC line, because it's above the most congested interface in ISO New England, it would make -- the scheduling would be difficult. Would that not be the case if this were an AC line?

MR. WHITLEY: Well, the scheduling to the DC terminal may be the same, you know, if the terminal were up in Canada and the AC network were in Maine. But in general, just so you understand how they work, A DC line typically has a fixed

schedule over an hour. It's not as flexible as a generator is which can go up and down. So when there's sudden changes on the system, it doesn't respond the same way as an AC network does where there's instantaneous change and the operators posture the system to be able to withstand the next worst contingency. The AC systems instantly respond; the DC system doesn't. So if there were a contingency or a loss of a line that required some sudden, quick change to reduce an overload, what most likely would happen, wind would be curtailed in Maine as opposed to this project being backed off because it's not as flexible to be changed.

MR. BRYANT: So it's not, then, analogous or directly analogous to a 1,200-megawatt power plant sitting in Lewiston?

MR. WHITLEY: It's not quite as flexible as a power plant. In some ways, it's -- you know, when you think about the Hydro-Québec system with a big pond that can be scheduled peak and off peak, in some way it's great. But instantaneous within the hour kind of changes it's not.

MR. BRYANT: Can it be used to balance intermittent wind and solar that's elsewhere on the grid?

MR. WHITLEY: If scheduled an hour ahead of time but not an instantaneous way.

MR. BRYANT: When you -- your last phrase there, "or lead to curtailment of renewables," is that because of the scheduling you've just described or is that because --

MR. WHITLEY: Yes, that's what I was talking about. If there's a sudden contingency and the operators have to back down something, they can't get to that in less than an hour, renewables are likely to be the thing that gets curtailed.

MR. BRYANT: So it's not because of the bid stack and the energy market. It's --

MR. WHITLEY: Physical limitations.

MR. BRYANT: Okay. Now --

MR. WHITLEY: Now hopefully that can be changed over time and that scheduling can be much faster. That's something that I pushed for when I was in New York, but it's something that's been difficult to get accomplished.

MR. BRYANT: Okay. Thank you. Now if you could turn to page 17. Again, you're talking about the benefits of AC over DC. And the second half of the first paragraph in sub-letter B, help me understand that. So the AC line can be upgraded to carry more energy and capacity, I understand that, because it's the cost of the converter station is -- makes it uneconomic for new plants to connect.

MR. WHITLEY: Right.

MR. BRYANT: But the second little I, "The flexibility of the AC system will not take away the transmission capacity headroom from the surrounding lines but the DC line would." Can you explain what you mean by that?

MR. WHITLEY: Well, the -- if a robust AC system is

developed there with parallel paths, it would actually add to the headroom available to the network. The scheduling of power into Maine or into New England through Hydro-Québec would use up that headroom if -- unless there were additional capacity available. And if the -- if no additional transmission were built into the network through Maine to get to the rest of New England, you would have the congestion that we've shown you in this analysis and the curtailment numbers that are shown in this analysis.

MR. BRYANT: So is your reference to the surrounding transmission lines, is that a reference to the bottleneck at the interface then?

MR. WHITLEY: Yes.

MR. BRYANT: Okay, all right. You're not talking about western Maine -- the headroom that may or may not exist in western Maine. You're talking about the interface.

MR. WHITLEY: The interface to southern New England.

MR. BRYANT: Okay, okay. Thank you.

MR. WHITLEY: Thank you.

MR. BRYANT: That's all.

MR. SIMPSON: Does anyone else have any questions for this witness? Okay, and I just want to confirm there are no questions of a confidential nature for this witness as well?

MR. DES ROSIERS: CMP has no confidential questions.

MR. SIMPSON: Okay. And CLF, no confidential

questions? Okay, great. All right, Mr. Whitley, thank you very much.

MR. WHITLEY: Thank you.

MR. SIMPSON: What we're going to do now is we're going to take a quick break. We're going to go into in camera session to discuss confidential information. There are several protective orders in play. Protective Orders 1, 2, 4 for CMP and Protective Order 8 relating to LEI confidential information. Everybody in this room has executed an NDA for Protective Order 8. Is CMP good? All right, great. So nobody in the room has to leave. We're going to hang up the phone. Eva, do you have the four-digit PIN to call back in on?

MS. WANG: I do.

MR. SIMPSON: Okay, great. So we're going to hang up the phone now and you're going to have to call back in.

MS. WANG: Sure, thank you.

MR. SIMPSON: All righty. All right, so we'll take five minutes while we make the transition. Then we'll bring the LEI team back and we'll go with confidential questions for that group of witnesses. Thank you.

CONFERENCE RECESSED (June 14, 2018, 3:33 p.m.)

CONFERENCE RESUMED IN CAMERA

(June 14, 2018, 3:38 p.m.)

C E R T I F I C A T E

I hereby certify that this is a true and accurate transcript of the proceedings which have been electronically recorded in this matter on the aforementioned hearing date.

D. Noelle Forrest

D. Noelle Forrest, Transcriber