MAINE PUBLIC UTILITIES COMMISSION
AUGUSTA, MAINE

IN RE:	)	
	)	Docket No. 2017-232
CENTRAL MAINE POWER COMPANY	)	January 10, 2019
	)	

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)

APPEARANCES:

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JOHN FLUMERFELT, Calpine Corporation
TANYA BODELL, Energyzt, Calpine Corp., Vistra Energy, Bucksport
ANDREW LANDRY, Preti Flaherty, Industrial Energy Consumer Group
SUE ELY, Natural Resources Council of Maine
PHELPS TURNER, Conservation Law Foundation
AMY OLFENE, Drummond Woodsum, NextEra Energy Resources
BRIAN MURPHY, NextEra Energy Resources
BEN SMITH, Soltan Bass Smith, Western Maine Mountains & Rivers
DOT KELLY

CONFERENCE COMMENCED (January 10, 2019, 9:02 a.m.)

MR. SIMPSON: Good morning, everyone. This is a hearing before the Maine Public Utilities Commission in docket number 2017-00232 which is Central Maine Power Company's request for approval of a certificate of public convenience and necessity in the New England Clean Energy Connect project. Notice of today's hearing was provided by a Procedural Order issued on November 2nd and a second ordered issued on January 4th. The purpose of today's hearing is to allow for the cross examination of the Daymark panel and CMP's engineering panel. I want to begin with appearances. Let's start with the people in the room, and then we'll go to the parties who are on the phone. Drew, let's start with you.

MR. LANDRY: Okay. Andrew Landry from Preti Flaherty on behalf of Industrial Energy Consumer Group.

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

MR. TURNER: Phelps Turner, Conservation Law Foundation.

MR. SIMPSON: Let's go to the panel. Yeah, go ahead.

MR. TRIBBET: Justin Tribbet representing Central Maine Power.

MR. HODGDON: Scott Hodgdon representing Central Maine Power.

MR. MALONE: Chris Malone, Avangrid.

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

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

D. SMITH: Doug Smith with Daymark Energy Advisors on behalf of Central Maine Power Company.

MR. STINNEFORD: Eric Stinneford, Central Maine Power.

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

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

MR. SIMPSON: John, would you start there and we'll come forward?

MR. FLUMERFELT: John Flumerfelt, Calpine Corporation.

MR. BARTLETT: Steve Bartlett, Foley Hoag on behalf of the generator interveners.

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

MS. BODELL: Tanya Bodell with Energyzt on behalf of the generator interveners.

MS. KELLY: Dot Kelly, Phippsburg, Maine.

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

MR. MURPHY: Brian Murphy on behalf of NextEra Energy Resources.

MR. DICKINSON: Thorn Dickinson, Avangrid Networks.

MR. SIMPSON: Barry, would you like to enter your appearances?

MR. HOBBINS: Barry Hobbins, Public Advocate on behalf of the Office of the Public Advocate.

MR. SIMPSON: Thank you. That takes care of the parties in the room. Could we get the parties who are on the phone, please, to enter their appearance? Ben?

B. SMITH: Good morning, Chris. This is -- yeah, this is Ben Smith on behalf of Western Mountains & Rivers Corporation.

MR. SIMPSON: Thank you. Are there any other parties on the phone? Okay, based on -- well, let's just go right to the questioning. I would like to shoot for a morning break at around 10:30. So just for planning purposes, keep that in mind as you're asking questions. Let's start with NextEra. And I would note that the witnesses have already been sworn in this case.

MR. MURPHY: Thank you, Chris. I do not have any initial questions for the witnesses, but I'd like to reserve the right if I have questions based on other interveners' questioning of them.

MR. SIMPSON: Okay. What we've traditionally done is gone in the order of estimates with the highest estimates first. So, Sue, you're up.

MS. ELY: I actually don't have any questions.

MR. SIMPSON: Okay. Oh, my goodness. I wasn't expecting this. So, let's see --

MS. TRACY: Town of Caratunk had ten minutes and Dot Kelly had ten minutes.

MR. SIMPSON: Yeah, I know. But Elizabeth Caruso appears not to be on the phone. So, Dot, you're up.

MS. KELLY: Thank you. Good morning, gentlemen. I really only have one question, and I'd like each of you to answer it. I realize that you are not actually working for CMP so I'd like you to answer it from CMP as well as from -- if you're in a different organization, from your own organization. And that is regarding safety and environmental protection. How has management told you to consider those aspects as compared to scope, cost, and, you know, time difficulties that you're running into? So that was scope, cost, and time in safety and environmental protection. And you can decide how to respond.

MR. MALONE: I guess I'll start first and foremost. I'm Chris Malone from Avangrid. I work in the transmission planning department so we are actually, although I announce myself as Avangrid, we do have roots in every single one of the opcos. My boss specifically manages the CMP team. So in terms of representation of CMP, I feel that I'm adequate in representing the interests of CMP. In terms of safety and environmental, I think your question -- I'd like to get some clarity on that. You said conversations that I've had with management. I'd like you to elaborate a little bit on what you mean by that. Just trying to best answer your question.

MS. KELLY: Right. There was a recent PUC decision discussing the metering. I don't know if you're familiar with 2018-00052 where there was an audit, and it specifically highlighted that CMP management appeared not to be focused on reporting on quality, safety, or reliability, environmental and were more focused on the three items that I mentioned which was scope, cost, and time.

MS. TRACY: Objection, assumes facts not in evidence. We don't agree with the characterization of the audit report.

MR. SIMPSON: Yeah, Dot, we need to focus on this case.

MS. KELLY: Okay, fair enough. But that was -- I was giving that as a preface. So things like weekly safety meetings. When you did your reports, were people interested or were you required to get back to management on safety and environmental concerns or was it more focused on scope, cost, and time?

MR. MALONE: I guess as far as what I do specifically in transmission planning, you know, we do focus on normal and extreme design contingencies so that when the project is ultimately in service, it operates as designed which is, in my world, determining and ensuring safe operation of the project. I'm sure Justin could probably elaborate a little bit on the specifics in the RFP perhaps in terms of safety and environmental protection. In terms of communication with management, weekly safety meetings and things of that sort, what I can say is that the company places very high emphasis on that. All of my staff, there's a very rigorous safety program. It's actually electronic, and we all enforced (sic) to take that safety training. At the onset of every single one of our meetings, we typically have a safety tip. So although that may not apply specifically to this project, I am confident in saying that our company places the utmost importance on safety.

MR. HODGDON: So my name's Scott Hodgdon. I'm with Burns & McDonnell for Central Maine Power. And I guess from the Central Maine Power perspective in terms of scope and safety and reliability and so on and so forth, I think Chris described it well. From the planning perspective, when we're conducting our analyses, we're conducting them in accordance with ISO New England procedures, NPCC procedures, and NERC procedures. And those outline the specific contingencies we need to test and the performance that needs to be observed after those contingencies are tested to make sure that the project operates reliably, the system operates reliably, after all these contingencies. So from a reliability standpoint, I think, you know, that was in our scope and that was our task and what was outlined in the report that we ultimately produced.

From the -- you know, the Burns & McDonnell standpoint, you know, talking -- kind of going off of what Chris was saying, safety is the number one topic of all meetings in Burns & McDonnell. We start off every single meeting with a safety moment. Somebody will describe, you know, be careful on the ice or something on that. It depends on really the season or something like that, but it is always the first thing that is discussed in any meeting. So it's kind of -- it's very -- it's put high in priority in terms of the company goes (sic), you know, and I like to bring that into everything that I do, although I, you know, sit there at a desk and run the study --

MS. KELLY: Absolutely, yes. And I don't want to doubt that. As engineers, it's been your education, etc. that that's -- it's not useful to design something that's going to cause injuries and difficulties. So thank you. And Justin?

MR. TRIBBET: Sure. So I guess focus more on the RFP response which I think was the intent of your original question. I think it's fair to say that the goal of CMP in the tender process was to put forth a project that's constructible, competitive, and hopefully what ultimately gets selected. For the purposes of the safety discussion, I think generally we've heard that covered by others. We've talked a little bit about codes, NESC, OSHA, and the list goes on and on. And we actually tried to address as well the safety concerns in ODR 030-001 where we attached, I believe, some of the CMP safety requirements. Specific to safety currently, we actually have a dedicated safety engineer. It's not my sort of area of expertise, but we have a safety engineer on the project that's actually reviewing the design against the OSHA standards. As an example, I had a discussion with her fairly recently about fall protection and these types of things on the transmission line poles where she is sort of reviewing each passage of the OSHA requirements and trying to carefully make sure that our design does, in fact, comply with OSHA and ensure that we have designed the safety possible structures.

Specific to environmental, I guess you talk about this balance, and I think it's a good discussion and it makes sense. I think one area that really represents this is that, I mean, CMP is committed to making sure that we have a proposal that's constructible and permittable. And, you know, I think my favorite example of that is if you look at the overhead DC line route, I mean, it's quite easy to put a pin at Appalach (phonetic) substation and Larrabee Road substation. And when you look at the corridor that CMP has defined, it's very clear that this is not a straight-line corridor. A lot of analysis was put into the corridor routing, and two-thirds of the DC line actually follows Brownfield corridor which, in my mind, helps minimize the environmental impacts of the project. So I -- again, I really feel like it's integral to everything we do. I'm not personally on the environmental side. We have a whole team that's dedicated to that, and we work together with them all the time. And ultimately, if -- in the end I think everybody at CMP realizes that, I mean, you can bid the cheapest possible project, but if it's not permittable, if you can't get it all through the environmental studies that, in the end, you don't have a real project. So I feel that the environmental and safety has really been a focus and a priority for the company. That's at least my observation.

MS. KELLY: And I'd like you to -- thank you very much. And I'd like you to talk about undergrounding and the work that has been done at CMP, including direction from CMP regarding undergrounding.

MR. TRIBBET: Okay.

MS. KELLY: Thanks.

MR. TRIBBET: In regards to -- can you clarify the question? Is it cost or whether or not we're going to underground or can you kind of provide a little bit of direction on that?

MS. KELLY: Sure. Since you're the engineers, I want to know whether you considered undergrounding, whether you have any experience with the costs of underground, whether that was given to management as options.

MR. TRIBBET: I guess maybe taking things one at a time, in regards to the cost of undergrounding, Chris?

MR. MALONE: Yeah, the cost of undergrounding in my experience is roughly, depending on voltage class certainly, irregardless of whether --

MS. KELLY: Okay, and let's focus on HDVC (sic), high --

MR. MALONE: That's what I was getting to. Regardless of the technologies, conductor is conductor, digging is digging. And in Connecticut specifically, because that's where I'm out of, it's a roughly three to four times the cost of overhead.

MS. KELLY: And a question for that. Has that been in open fields and forests as you would have through most of the new corridor?

MR. MALONE: Typically in Connecticut, the underground construction is in more of an urban area.

MS. KELLY: And do you have a feeling whether that makes a dramatic difference in cost?

MR. MALONE: I wouldn't -- I would probably allow Justin to speak more elaborately on that. There are challenges with going underground in the middle of the forest. You can hit rock. You can hit -- you may have other challenges. I'm a transmission planner. I don't know all the intricate things that can happen, you know, in those types of conditions, but general rule of thumb is the cost of underground is substantially higher than the cost of overhead.

MS. KELLY: Thank you.

MR. TRIBBET: And I guess just in my own mind, I've been listening to people talk about the mountains of the area throughout these various cases as it has evolved, and I can't help but think that there would be some significant challenges trying to route an underground line through this particular 53 miles of very rugged terrain in northwestern Maine. However, as previously noted, there was no actual detailed study done in that area. I guess some general notes and thoughts from my perspective. I mean, first I would say that, in my opinion, the 83D RFP and the subsequent contracts that CMP has entered into are generally more consistent with an overhead line in the sense that, typically on an overhead line, you have temporary faults that are -- that quickly and automatically restored (sic). While there may be less faults that occur on an underground circuit, when those faults do occur, typically restoration times are very long, and, unfortunately, that is problematic from an overall availability and from the damages that CMP may face in the contracts.

In terms of CMP as a company, I would say that they're more suited for maintenance of overhead transmission lines. The overhead transmission lines in the state have a very high degree of availability, over 99 percent if I recall correctly. And from a tooling, manpower, equipment, CMP is really, in my opinion, a poles and wire company. So I guess I see that as another factor. And obviously cost, I mean, as you've already alluded, is higher for underground.

MR. HODGDON: And I guess just to add one more thing, I mean, from the -- again, from the system planning and the system performance evaluation perspective, when we do these analyses, really what we want to make sure of is if a fault does occur, number one, that it clears and it can be cleared, and then, number two, that the system performs according to criteria. So the system comes back to a stable state. You don't have a large loss of source above, you know, criteria, whichever you're looking at. And, you know, underground versus overhead, again, what we're looking at is, you know, does -- is the fault cleared, can it be cleared within a certain amount of time, and then how the system responds. So I guess really from the planning perspective is it really doesn't matter overhead versus underhead (sic) as long as the system performs appropriately.

MS. KELLY: Thank you. Did you have any conversations or information from Hydro-Quebec about their proposals to put these cables underground?

MR. TRIBBET: Yes. I don't recall the exact date.

We did ask if they were planning to have underground on their side, and they indicated that they are not.

MS. KELLY: Are you aware in the documents that were prepared for our review that they did want the ability to be able to put it underground?

MR. TRIBBET: That's correct. My understanding is as part of the permitting process, in the event that that was a requirement on their side, they wanted to be able to accommodate that requirement. That's correct.

MR. HODGDON: I did not have any conversations with Hydro-Quebec about overhead or underground.

MR. MALONE: Echo what Scott said.

MS. KELLY: Okay. Thank you very much. No further questions.

MR. SIMPSON: Thanks. Brian, do you have a --

MR. MURPHY: I do have questions based on Ms. Kelly's questions, and it's more for clarity of the record. The HVDC technology that you're using is the VSH technology, correct?

MR. TRIBBET: VSC, voltage source converter.

MR. MURPHY: VSC technology. You also know that the use of that technology throughout the world, not just in this region, is probably above 90 percent underground or undersea cable, correct?

MR. TRIBBET: Correct.

MR. MURPHY: And in the end of the discussion with

Ms. Kelly, you talked about faults, which are -- concede are very important. But I also believe it's correct to say that you have not done an analysis of underground faults for this type of technology in this -- on this line. Correct?

MR. TRIBBET: Can you clarify the question? When you say have we done an analysis for underground faults, what do you mean by that?

MR. MURPHY: What I'm getting at is I think it's -- I think you correctly stated that there is more concern with overhead. You'll have more faults, lightning strikes. Trees will fall into it. But I also heard a statement that underground faults can take more time for restoration. And I challenge that you have done any analysis on this technology for this line that supports that fact.

MS. TRACY: Objection, assumes facts not in evidence. We don't agree with the characterization of the technology.

MR. SIMPSON: I'll allow it. Go ahead and answer the question, please.

MR. TRIBBET: So again, no study has been done. The comment is based on CMP's experience maintaining hundreds if not thousands of miles of line. I would also note that the comment about trees falling into the line is very unusual on the transmission system. Certainly on the roadside distribution where you have eight feet of trim, you know, that could occur. In a transmission right-of-way with 75 feet of clearing on either side, that's not expected.

MR. MURPHY: Isn't it true, though, in a right-of-way, transmission right-of-way, you will have tree limbs that will blow into the conductor and cause a fault?

MR. TRIBBET: Certainly that can happen. The majority of things that we see on the protection and control reports that get circulated in our company are more of temporary faults. You know, a tree limb may, you know, sway into a line and, you know, the line will trip and within five or six cycles, within a couple milliseconds, it'll trip back and it'll restore service. It's very rare that we see permanent faults. I mean, so when we say the likelihood of seeing a fault, I think Justin -- I don't want to speak for him, but he may be classifying both temporary and permanent faults into the overall bucket. Based on my experience and what I've seen in the reports that are published in our company, the majority are temporary faults that are automatically restored after a closing occurs.

MR. MURPHY: Thank you, Chris. Those are all my questions.

MR. SIMPSON: Phelps, did you have any questions for this panel?

MR. TURNER: No, not at this time. Thank you.

MR. SIMPSON: A couple minutes ago I heard another beep. Is there anyone else on the phone, and in particular, is

Elizabeth Caruso on the phone?

MR. PULLARO: It's Francis Pullaro, RENEW Northeast. I joined late.

MR. SIMPSON: Hi, Francis. Are there any questions from the bench for this panel? Okay, do you have any redirect?

MS. TRACY: I do.

MR. SIMPSON: Okay, go ahead.

MR. TURNER: Sorry, Chris --

MS. ELY: I do have a follow up.

MR. SIMPSON: I'm sorry. Let's hold off on the redirect. Sue, go ahead.

MS. ELY: You mentioned that although it sounds like faults are not -- that if faults occur, do you -- as part of the proposal, do you have a separate crew then that would be available to correct these faults? Where would the manpower come to correct these faults?

MR. TRIBBET: Well, again, I think kind of stepping through the different discussions here, as we previously discussed, on an overhead, most faults are temporary in nature. For the faults that are temporary in nature, the system is designed with automatic reclosing. So you have the temporary fault. The system opens. You allow the air to deionize, and then at which point you would reclose the line back in automatically. So these types of temporary faults happen not all that often, but when they do happen, they automatically restore themselves. I think what you're asking about is, and just to be sure I'm clear, a permanent fault on the overhead line. Is that the question?

MS. ELY: If a permanent fault is a situation where the energy cannot flow across the line unless you send a human out to correct it, then yes.

MR. TRIBBET: Sure. So the faults that don't then reclose, as we've discussed, automatically, typically would then be flown by helicopter. Out of the relaying, the protective relaying for the line, you typically get a distance-to-fault reading so you have a pretty good sense of where the fault has occurred. The line, as you probably know, spans a large part of the state. It's 145 miles long. Based on that fault location and then the corresponding helicopter flight, CMP would dispatch crews from its nearest service center. I mean, there's a variety of service centers throughout the state. I don't have the list offhand, but, I mean, certainly there are service centers in Lewiston close to the converter end. There's a service center in Jackman. And there's various service centers in between. So, again, the intent would be to try to allocate resources to minimize the amount of down time based on the location of the fault.

MS. ELY: So it would be utilizing Central Maine Power's existing infrastructure resources to restore that permanent fault?

MR. TRIBBET: Well, subject to the discussions about the special-purpose entity and the ongoing discussions with counsel and the Commission on that, assuming CMP owns the line, is that the nature of your question or are you assuming a special-purpose entity?

MS. ELY: I guess at this point, Central Maine Power would own the line. I don't know how it would be structured.

MR. TRIBBET: Okay. Okay, if -- assuming CMP owns the line, then absolutely CMP would utilize its own crews. I think there -- if I recall in the maintenance plan for the project, there was an assumed -- and I don't have the numbers offhand, but my recollection is there's assumed staffing implementation or augmentation as a function of the project. But I'd have to check the details of that. Was that the question, are you going to try to -- are we going to try to use our existing resources or are we going to add resources? Was that the question?

MS. ELY: Yes.

MR. TRIBBET: Yeah, and I believe there is resources and money in the maintenance plan for the project to support the maintenance activities. Actually I don't believe that. I know there is money allocated for maintenance activities in the project budget.

MS. ELY: Okay. And so in a situation where you have a -- sort of a simultaneous fault, a permanent fault, on the

NECEC line and faults on other lines that CMP maintains, is there a hierarchy of priority?

MR. TRIBBET: So let me make sure I understand the scenario. So you're asking if there are -- imagine NECEC has a permanent fault and then, let's say, a distribution line that feeds Jackman also has a fault. Is that kind of the scenario you're thinking of?

MS. ELY: Yeah. It seems like when bad weather strikes or calamity strikes, it's rarely just one spot. So I'm curious is the augmentation enough that it wouldn't, you know, cause the company to have to make a choice between fixing the NECEC versus restoring other transmission line --

MR. TRIBBET: Right, and I guess following the Jackman example, I mean, I guess I would just note that even the equipment is different. You know, where you've got a 320 kV HVDC line that's primarily in right-of-way that you're going to have to access with track buckets and very large equipment and roadside distribution, as an example, is a totally different maintenance problem in the sense of you're going to be using wheeled machines that are capable of driving on the road, the typical bucket truck that folks are used to seeing. So I -- in that scenario, I don't see a lot of conflict because the equipment and -- is different. I mean, and to some extent, you know, the manpower is even a little bit different in the regards of, you know, typically a distribution lineman wouldn't go work perhaps on a 320 kV DC line the same day if that makes sense --

MS. ELY: So hypothetically when you need to dispatch this helicopter, is the -- is there -- are there going to be -- is there going to be another helicopter at -- or are you having to choose between sending a helicopter to fix one line versus another large line in the state?

MR. TRIBBET: Right. And I guess regarding the helicopter, I mean, to the best of my knowledge, CMP does not own or -- and -- does not own its own helicopter fleet. It relies on a network of contractors to pay to do that. My assumption is, as we discussed before, there is money in the maintenance budget to support this exercise. And my assumption is that there's going to be an agreement with the helicopter company to be able to offer those services. I don't know if that helps.

MS. ELY: That's very helpful, thank you.

MR. SHOPE: I don't know if this is the appropriate moment, but I just want to note at some point I do have a follow up.

MR. SIMPSON: Go ahead, John.

MR. SHOPE: So with regard -- just to clarify, with regard to the maintenance and repair of the line, obviously the current proposal is that the HVDC line would be owned, operated, and maintained by CMP itself, but there has been some discussion of possibly trying to segregate some portion of the HVDC operation off to a so-called special-purpose entity. Are you with -- are you in agreement so far?

MR. TRIBBET: While I'm not an expert or involved in the special-purpose entity discussions, I am aware that that is correct, yes.

MR. SHOPE: Okay. So putting aside the legalities of that and recognizing that you're an engineer, just from the point of view of efficiency and cost, would it be your understanding that it would be favorable to have a sharing of personnel so that CMP repair staff, for example, the folks that you mentioned in Lewiston and Jackman, would be available to come work on the HVDC line if there were a fault or some other problem with it?

MR. TRIBBET: That seems reasonable to me, yeah.

MR. SHOPE: Okay. So -- and, again, recognizing that you're not a lawyer, presumably at some point then if the HVDC line were to be stipulated into a special-purpose entity, there would need to be some sort of agreement between CMP and the special-purpose entity about how to charge the special-purpose entity for the services of CMP in maintaining and repairing or restoring the line.

MS. TRACY: Objection. This line of questioning is not appropriate for our engineering and planning witnesses. We do have witnesses available who have testified yesterday who are still available to testify to answer that question. We'd be happy to answer that question, but we don't think that Mr. Tribbet is the appropriate witness.

MR. SIMPSON: Sustained. I agree.

MR. SHOPE: That's fine.

MR. SIMPSON: Brian, did you have another one?

MR. MURPHY: Yes, a follow up on the system restoration questions. And, again, these questions really are for clarity of the record and based on my own experience. We talked about a distribution/transmission priority. I think the question was if you have a storm that comes through that takes out multiple bulk system transmission elements as well as distribution, is there a procedure in place on the prioritization of the bulk system restoration, which I consider to be 69 or a hundred kV and above, versus this line which is a -- as it was described yesterday, a competitive transmission line? So AC lines that serve load that are hundred kV and above versus this line, is there a procedure in place on the priority of restoration?

MR. TRIBBET: I guess first I would caveat it by saying that I'm not an expert on all the maintenance procedures of Central Maine Power. Taking that as it is, I would say that generally I agree with your assessment that typically restoration priority is given to higher-voltage lines. I guess I -- similarly to the discussion yesterday, I struggle with the concept of separating somehow this line from the other lines because, again, in my mind, they all are for the purpose of serving load and being part of an interconnected system. So I struggle to see the difference in the segregation of these lines, but, yes, I agree that higher-voltage lines typically would get priority for restoration, yeah.

MR. MURPHY: Thank you.

MR. SIMPSON: Any other cross examination questions for this panel? All right, let's go to redirect now.

MS. TRACY: Okay. There were some questions by Ms. Kelly regarding the environmental impacts of -- and CMP and Avangrid's considerations around environmental impacts regarding this project. There's also been discussion about undergrounding the HVDC line. What is your assessment of the environmental impacts of going underground versus aboveground?

MR. TRIBBET: Again, while I have conducted no study, I mean, my immediate impression is that the -- there would be a similar set of environmental impacts in constructing an underground line through the mountainous territory of northwestern Maine.

MS. TRACY: Would there be any -- you said mountainous territory. Would there be any blasting involved with that, do you think? In your experience.

MR. TRIBBET: I think given the terrain, it's certainly likely that you're going to encounter rock and that would then require blasting, yes.

MS. TRACY: And with respect to, say, to wetlands, is there -- you know, as I understand it, you'd be digging a trench down the corridor for undergrounding. What is the relative impact of trenching the HVDC line to wetlands and vernal pools versus -- and I understand you're not an expert, but just in your experience because you do have some underground lines in the CMP territory -- those impacts relative to placing them aboveground and just needing to place poles?

MR. TRIBBET: Again, I'm not an expert, but my impression is that using the transmission line overhead construction strategy of matting and very carefully trying to avoid impacts to these wetlands that, in fact, trenching and burying equipment in the wetlands would be more disturbance in my mind. But again, I'm not an expert.

MS. TRACY: Okay. There was some discussion earlier about -- from Ms. Kelly's questioning about safety considerations. Do you have any concerns about the safe operation of an overhead HVDC VSC line as proposed in this project?

MR. TRIBBET: No. No, I have no concerns.

MS. TRACY: Are you aware of anybody else in your team or at the company that has concerns about that?

MR. TRIBBET: No, I'm not aware.

MS. TRACY: There was a safety concern that has been brought up in this proceeding, and particularly yesterday, about if there is a fire or if there is some sort of injury, that actually there may be insufficient resources up in these remote territories for safety responders to address the safety situation. Do you have a response to that particular safety concern?

MR. TRIBBET: My understanding is, as part of the transmission line construction RFP, they are going to include requirements for the first response to be in the scope of the contractor, the idea being to try to alleviate any concerns with the response time given the remote nature of the territory and the limited number of responders to cover that territory.

MS. TRACY: There was some discussion about faults and temporary and permanent faults. And with respect to permanent faults that require a crew to be dispatched to address the situation, you identified and described what would happen in an overhead situation. Can you identify what would be involved with addressing permanent faults if the line were actually to be buried under -- if the HVDC line were to be actually buried underground? Are there some additional considerations with identifying permanent faults and then also getting to and addressing permanent faults?

MR. TRIBBET: Sure. In that scenario, I mean, I think also -- so the conversation's very similar. You would get some sort of fault location hopefully from the protective devices. In the sense of underground, I think the challenge is finding the location of the fault. Once you've found the location of the fault, now, again, you're into this situation that you have to basically dig up, reconstruct. And I guess the concern that I have is certainly it's a very remote territory up there. I think -- I guess I could see potential problems and challenges on the maintenance side of that particular arrangement, especially in the 53 miles that is very remote in northwestern Maine.

MS. TRACY: I am aware that CMP has underground lines, and, while they're not HVDC lines, is there any experience with underground faults on CMP's existing system or anywhere in Avangrid's system that you can --

MR. MALONE: So one that comes to my mind recently a few years back in Connecticut one of our 345 kV underground cables was out of service for roughly two months. We do have dedicated manholes on the street in that 15-mile path, and it took roughly two months to restore.

MS. TRACY: And why was that? Why did it take two months to restore on a 15-mile path?

MR. MALONE: Similar to what Justin alluded to. Now it's a little different in an urban area, right, because if the fault is in between two manholes, you better know where the fault is because you're about to dig up the street. So, you know, confirming specifically where the fault is, they have devices that they could go down into the manhole and they could shoot current or voltage towards -- in that direction to, I guess, verify that the fault is actually in between two manholes. So that process on a 15-mile path in an urban area takes time. But similarly, if a fault were to occur, I think 53-mile stretch of underground, it would -- you know, you'd have similar challenges. In fact, you probably -- you wouldn't have the ability to go down into a manhole which are, I guess, constructed, segmented portions of the line that would allow you to, I guess, test the intermediate sections as to where a fault could occur. But, again, I'm not -- again, transmission planner. This is just my experience from PEOAs and other things that have been published by our team.

MS. TRACY: I guess the only question I have is we have obviously Mr. Stinneford available to talk about the allocation of resources in the event of, you know, sort of there's a -- we have an SPE or even priority of resources if the line is held within CMP. We -- I would typically -- I'd like to redirect to Mr. Stinneford to answer those questions, but I'd ask permission because obviously he's not on this panel right now.

MR. SIMPSON: So are you proposing to add Eric to the panel now?

MS. TRACY: Correct.

MR. SIMPSON: Yeah, let's go ahead and do that.

MS. TRACY: Okay.

MR. SHOPE: I object. The question that I asked that was on this line was excluded so --

MS. TRACY: Actually Ms. Ely's question.

MR. SIMPSON: Okay, but John did have a question that was definitely related to this, and I would say if we do add Eric to the panel, we would allow John to ask the question. And then you can do redirect at that time.

MS. TRACY: Agreed.

MR. SIMPSON: Thank you very much. Sure.

MS. ELY: Just to clarify, my question was not about the -- it was how it would be done under Central Maine Power.

MR. SIMPSON: Yeah. So, John --

MS. KELLY: Point of information for me, I have a question that I'd like to ask based on underground and the document that CMP prepared for the various alternatives, and this would really be the TDI. They described specifically how they would underground.

MR. SIMPSON: So Dot, Dot, any follow-up questions have to relate to the redirect that we just had.

MS. KELLY: It would.

MR. SIMPSON: So let's do it one step at a time. I'm going to allow John to restate the question and ask Eric to respond. And then once that happens, Sarah, you can do your redirect on that. And then, Dot, we'll go to you. So, John, would you restate your question, please?

MR. SHOPE: Sure. So the first question along this line was in the scenario that Mr. Tribbet had mentioned where the -- some portion of the HVDC line operation gets housed in a special-purpose entity rather than being housed within CMP itself, with regard to a sharing of personnel for the maintenance and restoration of the line, the first step is that there would presumably need to be some sort of agreement between that special-purpose entity and CMP with regard to how that sharing would occur. Is that fair?

MR. STINNEFORD: Yes, I mean, as we have talked about the special-purpose entity to date in this case, its primary purpose has been to financially ringfence the project from CMP, and we would expect that there would be affiliate services agreements in place between the special-purpose entity and CMP for the sharing of resources. And I think we have a very clear model for how that would work based on Maine Electric Power Company today which is an affiliate of CMP which has no employees, no resources. It utilizes the resources of CMP for the operations and maintenance of the line. We would expect this SPE to work similarly.

MR. SHOPE: So presumably the parties -- in the first instance, the parties would have to determine what would be the fair value of having the CMP repair staff there essentially as kind of an insurance policy against a -- you know, a major default event on the HVDC line. Is that fair?

MR. STINNEFORD: No, I would not agree with that. The practice of this Commission and statute is that those affiliate services are provided at cost, not on any kind of value proposition. And it's -- you know, it's an allocation of cost based on actual costs.

MR. SHOPE: So when you say actual cost, meaning CMP would only have to pay -- I mean, excuse me, the special-purpose entity would only have to pay on some sort of a time and materials basis if there were actually a default event that occurred.

MR. STINNEFORD: As well as any other maintenance activities, yes.

MR. SHOPE: Okay. And is it your view that that -- now would the agreement need to place priorities as between repair of the HVDC line versus repair of CMP's local distribution? So, for example, if there were a major storm that came through and knocked out a lot of the local transmission and distribution and also knocked out a part of the HVDC line, would the agreement need to address how personnel would be prioritized in that scenario?

MR. STINNEFORD: Prioritization in restoration is really driven by operational needs and our restoration plan priorities. I don't believe that would be dictated by contract.

MR. SHOPE: So hypothetically, if there were the major storm that I just described that damaged the HVDC line as well as the local transmission and distribution, it's at least possible that some CMP work crews would be assigned, as Mr. Tribbet was indicating, to the higher-voltage line first even though that is one that's serving Massachusetts rather than Maine.

MR. STINNEFORD: Well, I would object to the classification of this serving only Massachusetts customers. As Mr. Tribbet testified, there's a different skill set and different equipment that are used for transmission restoration than distribution restoration. But the prioritization of restoration of this line versus other CMP transmission lines, that will be dictated by ISO New England and the bulk power system restoration priorities. And I would point out that, you know, if there is a fault on this transmission line or any other transmission line, it's going to impact CMP customers just as much as it is Massachusetts customers from a reliability and service perspective, you know, setting aside the commercial issues.

MR. SHOPE: And just to clarify, even though there may be some different equipment that's required for repair and maintenance of the HVDC line, there's also some common equipment and certainly common personnel that's contemplated.

Is that correct?

MR. STINNEFORD: Yes, as we've testified that -- you know, we think there are efficiencies to be gained by utilizing common employees and resources between CMP and the special-purpose entity, if there is to be one. Otherwise there would be a, you know, duplication of resources and resulting inefficiencies.

MR. SHOPE: That's it for me.

MR. SIMPSON: Sarah?

MS. TRACY: Actually my questions on redirect have been addressed so I'm all set.

MR. SIMPSON: Okay. So, Dot, and I'll just remind you, your questions need to relate to what Sarah's questions were on redirect.

MS. KELLY: And please tell me if it's not true.

MR. SIMPSON: Okay. I assume Sarah will tell us that.

MS. KELLY: I believe Ms. Tracy asked you about undergrounding. And my question is that whether you were aware that the TDI document prepared by CMP -- so this is comparable to other HVDC transmission lines -- stated that their undergrounding, which was going to be for the whole line, was going to be a four-foot disturbance, a four-foot-wide trench.

MS. TRACY: Objection. These are questions that could have been asked in Ms. Kelly's direct. I did not mention the other projects in my redirect.

MR. SIMPSON: Sustained. Dot, any other questions?

MS. KELLY: I would like to just question that for a moment because she did go broadly, and their response was assuming that it was going to be a very big disturbance to go underground. And so I think whether they had, as part of their review as the engineering team, reviewed those documents that were underground goes to Ms. Tracy's question.

MR. SIMPSON: Okay. The objection is sustained still.

MS. KELLY: Thank you.

MR. SIMPSON: Re-sustained. Are there any other questions for this panel?

MR. VANNOY: Just one follow up to Eric, just to fully understand the exchange there. It sounded like the transmission operator, ISO New England, when you have transmission failures and a lot of transmission out, it sounded like your answer was the transmission operator, ISO New England, not the transmission owner sets the priority of restoration of transmission. Is that correct?

MR. STINNEFORD: I believe that is typically the case, yes.

MR. VANNOY: Thank you.

MR. SIMPSON: Any other questions for this panel? All right, I want to thank the panel very much for your testimony. We appreciate it. And let's take a moment, shift gears now, and go to the Daymark panel. All right, we back on? And for the record, could the panel please identify yourselves?

MR. PEACO: Dan Peaco, Daymark Energy Advisors.

D. SMITH: Doug Smith, Daymark Energy Advisors.

MR. BOWER: Jeff Bower, Daymark Energy Advisors.

MR. SIMPSON: And you've all been previously sworn in this case?

MR. PEACO: We have.

D. SMITH: Yes.

MR. SIMPSON: All right, let's begin the questioning with the generator interveners. John?

MR. SHOPE: Thank you. Good morning.

MR. PEACO: Good morning.

MR. SHOPE: Obviously we've met before, but I'm John Shope representing the generator interveners. So I'd like to ask some questions obviously about the modeling that you've done of the -- what you state are the benefits of the NECEC project. So just to begin, just as a sort of historical matter, as it were, the modeling that you did was actually originally done for the purpose of supporting the RFP response that CMP was making in the Massachusetts 83D process. Is that correct?

MR. PEACO: Yes, we've done modeling for the project through the RFP development phase and through the application process.

MR. SHOPE: And as I understood a statement back in the spring by Mr. -- by Attorney des Rosiers, the modeling was done for Massachusetts, and the desire was -- and what was done was to use the same modeling for presentation in Maine. Is that correct?

MR. PEACO: We did -- initially we did -- the modeling that we did was focused on the report that we did that was submitted as part of the bid itself. And then we subsequently -- the bid was submitted in July of 2017 I believe, thereabouts, and the application here was filed in September. And we did the analysis in the report we submitted in the application based upon the modeling we did for the bid.

MR. SHOPE: For -- yeah, for the -- you based it on the modeling that you had done for Massachusetts.

MR. PEACO: For the bid.

MR. SHOPE: Yeah. And when you had done that modeling, I believe there's been reference to the fact that there was a very tight timeline for you to prepare that. I think it was just a few weeks if memory serves. Is that right?

MR. PEACO: In the -- in preparing the bid?

MR. SHOPE: Yes, in preparing the modeling in order to support the bid to Massachusetts.

MR. PEACO: That's correct. There were a number of things that had to come together precedent to -- yeah, as inputs to our modeling that were on a very tight timeline in the RFP development process.

MR. SHOPE: Sure. And now the purpose of the submission to Massachusetts that you were preparing was to show that there would be benefits to Massachusetts of accepting the CMP and the Hydro-Quebec bid. Is that right?

MR. PEACO: Well, the purpose of that report, of our modeling, was twofold. One, the initial purpose was to support the bid development team and their understanding the evaluation metrics and the quantification of those metrics as best as we could do as they were preparing the bid and positioning the proposal for the bid offering itself. And second -- the secondary objective was, once we completed that, was to prepare a report to submit to the evaluation teams in the proposal so that they had at least our view of the evaluation of the bid relative to the metrics set forth in the RFP.

MR. SHOPE: Okay. And so one of the things in the -- that was going to be important to the Massachusetts bid evaluation team was to see what would be the economic benefit to Massachusetts of choosing the Hydro-Quebec and CMP bid that was being made into the RFP.

MR. PEACO: That was part of the criteria, yes.

MR. SHOPE: Okay. And as part of that evaluation, you had to make assumptions or at least derive data about what background energy prices in New England would be without the

NECEC project. Is that fair?

MR. PEACO: We did a with and without NECEC analysis, correct.

MR. SHOPE: Sure. And so for -- so the first part of that is, okay, we need to find out what we think the energy prices in New England are going to be during the study period without the project and then compare them to what our model shows the energy prices will be with the project. Is that fair?

MR. PEACO: Correct.

MR. SHOPE: And one of the things that you found was that adding the project -- well, the higher -- is it fair to say that the higher your projection of the energy prices in New England without the project, the greater the price suppression benefit there would be of bringing in the Canadian hydro that was proposed as part of the bid?

MR. PEACO: I guess I'm not following the premise of your question.

MR. SHOPE: Sure, okay. So you said as part of your base case, you have to make a projection about what you think wholesale energy market prices are going to be in New England.

MR. PEACO: Correct.

MR. SHOPE: Yeah. And that's without the project, right? And then you compare that to what your model shows the wholesale energy prices are going to be with the project, right?

MR. PEACO: Correct.

MR. SHOPE: Okay. And again, I'm not accusing you of anything, but just as a factual matter, the higher the energy prices are assumed to be without the project, the greater the price suppression benefit would be of bringing the project in.

MR. PEACO: I guess the higher part is really where I'm confused. We prepared a reference case analysis with a set of assumptions we felt reasonable and, in many cases, conservative. We weren't -- if your implication is we were trying to come up with the highest possible before case to come up with benefits, that was not what we did.

MR. SHOPE: Okay. As I said, I'm not accusing you of anything. I'm just asking as a factual matter.

MR. PEACO: It came across that way so that's why I wanted to clarify.

MR. SHOPE: Okay. So I'm just trying to establish basic facts. Let me ask it a different way. If, in your base case, the assumed energy prices in New England have been lower than what you assumed, the price suppression benefit for Massachusetts would have been lower as well. Is that fair?

MR. PEACO: It's -- well, it's not exactly clear. It depends upon the nature of that I think, but as a general matter, the higher the prices, the more opportunity there would be for savings. But the relationships between what's displaced and how that affects prices would be subject to specific before and after assumptions. I'm not -- you know, I don't want to overly generalize the response.

MR. SHOPE: And if -- would it be fair to say that if the supply curve were steeper, then the savings would be greater?

MR. PEACO: The supply curve?

MR. SHOPE: You haven't been discussing supply curve in these proceedings for a month now?

MR. PEACO: I don't recall a discussion of supply curve with respect to our analysis.

MR. SHOPE: What's your -- you have no understanding of what supply curve means?

MR. PEACO: We did not have a supply curve in our analysis.

MR. SHOPE: Okay. Interesting. Okay, now do you have a generation supply stack, sir?

MR. PEACO: Maybe you need to define what you're asking about because I'm -- you're losing me.

MR. SHOPE: Okay, so have you ever heard of the phrase the supply stack in the context of calculating energy market prices?

MR. PEACO: With respect to the existing generators assumed in the mix? Yes.

MR. SHOPE: Yes, you have, okay. And so, in that context, you need to evaluate how the prices rise as you go up to the least efficient -- or the more costly generators, right?

MR. PEACO: So when you're using the term supply curve or bid stack, you're talking about the relative economics of the existing generating fleet that we assumed in our base case.

MR. SHOPE: Yes, in relation to that -- the -- and so that -- and the fuel inputs have a bearing on what that supply curve looks like, don't they?

MR. PEACO: The relationship between the cost of generation and the amount of load, yes.

MR. SHOPE: Yes, they do, okay. Now, just for Massachusetts, you did not calculate a wholesale capacity market price suppression benefit. Is that right?

MR. PEACO: Let me check.

D. SMITH: That's not correct. There was a capacity benefit calculation in the original bid submission.

MR. SHOPE: Okay. And is that something that the Massachusetts utilities actually thought was something that should be considered?

D. SMITH: My recollection is that in the initial -- in the original RFP there was, under I think it was other benefits section, a reference to capacity -- potential capacity market benefits.

MR. SHOPE: Have they since given any opinion about whether or not a capacity market benefit should be considered?

D. SMITH: I'm sorry, could you repeat that, please?

MR. SHOPE: Have they -- have the Massachusetts utilities subsequently expressed any opinion about whether there should be any capacity market benefit considered for purposes of the Massachusetts evaluation?

D. SMITH: I have no knowledge of whether they've said anything with respect to capacity market benefits.

MR. SHOPE: Okay. So now on the subject of capacity market benefit, with regard to your presentation to Maine, you did present a capacity market suppression benefit. Isn't that right?

MR. PEACO: Yes.

MR. SHOPE: Okay. And in fact, it was about 40 percent of the total wholesale electric market benefits that you calculated? Isn't that right?

MR. PEACO: I haven't calculated the percentage.

MR. SHOPE: Okay, well, maybe I'll help you out. Maybe some figures will refresh your recollection. Do you recall presenting wholesale energy market suppression benefits of $496 million in 2023 dollars? And that would be on page 11 of NECEC-5. Does that sound about right?

D. SMITH: Yes, that's -- that was the case run with the additional energy from the additional piece of the line.

MR. SHOPE: The additional energy from what?

D. SMITH: The -- I think it's probably clear to everybody here that the line as proposed is a 1,200-megawatt line with Massachusetts contracting for a piece of that, and then a piece of that additional, we ran two cases. We ran one for just the current estimate of energy delivered via the contract and then one with additional.

MR. SHOPE: One was with the 110 megawatt stub for spot sales.

D. SMITH: Yes.

MR. SHOPE: Okay. And so 496. And then do you recall presenting a capacity market benefit of $312, again in 2023 dollars? And just for reference, that's on page 14 of the same exhibit in the third paragraph.

D. SMITH: Correct.

MR. SHOPE: Okay. So now that you've -- now that I've refreshed your recollection as to those two figures, would you agree with me that the capacity market suppression benefit that you presented in your report was approximately 40 percent of the total wholesale electric market benefits that you were presenting as part of your report?

D. SMITH: I would agree that using those two numbers, the 312 is roughly 40 percent of the total of those two numbers, yes.

MR. SHOPE: Now, with regard to the capacity market benefit that you are presenting, that benefit would depend in part on whether or not the project would clear in the primary auction of the forward capacity market. I think we've agreed on that in the past, right?

D. SMITH: Yes.

MR. SHOPE: And in order to clear, it would have to have an approved bid that would be in compliance with ISO New England's minimum offer price rule. True?

D. SMITH: For that number, yes, that's correct.

MR. SHOPE: And so -- and that price -- in order for it to clear, the price would have to be lower than the market clearing price.

D. SMITH: Correct.

MR. SHOPE: Yeah, okay. And so you had actually -- you had originally planned to make a calculation of what the minimum offer price rule would be.

D. SMITH: In the early days of scoping out the work, we identified the minimum offer price rule as an input we would prefer to have.

MR. SHOPE: Yeah. And you -- ultimately you did not make that calculation because you didn't get the information that you had been expecting to get from Hydro-Quebec.

D. SMITH: I'm not sure I would agree that I was expecting to get. I certainly would have preferred to have gotten actual information. We did not get any information needed to calculate that so we did not calculate it.

MR. SHOPE: Okay. Well, you -- at a minimum, you had hoped to get that information. True?

D. SMITH: Yes.

MR. SHOPE: Okay. And you had also asked CMP to get that information for you from Hydro-Quebec. True?

D. SMITH: We had a number of conversations with CMP personnel about data that we would like to get from Hydro-Quebec and conversations we would like to have around commercially-sensitive information.

MR. SHOPE: Okay, but if you could just please answer my question. Did you ask CMP to get from Hydro-Quebec the information that you wanted in order to perform a minimum offer price rule calculation?

D. SMITH: I'm not trying to avoid your question. I do not know if, in that many words, I said I want this, this, and this. We had conversations about the kinds of information we wanted. We had communications around the information that would be necessary to make these calculations, and we certainly had calculations (sic) that that information would have to come from Hydro-Quebec.

MR. SHOPE: I'm really having trouble understanding why the answer to this question is taking so many words. You wanted to do a minimum offer price rule calculation. You were hoping to get the information from Hydro-Quebec. Did you ask CMP, get from Hydro-Quebec the information we need for the minimum offer price rule calculation? I think that can be answered yes or no.

MR. DES ROSIERS: Objection, argumentative.

MR. SIMPSON: Overruled. I want to hear the answer to the question.

D. SMITH: I believe I stated the answer would have to be no. I don't recall specifically asking CMP to go get a set of information from HQ.

MR. SHOPE: What about -- did anyone at Daymark make that request?

D. SMITH: Not to my knowledge.

MR. SHOPE: What about you, Mr. Bower? Is it your testimony today that no one at Daymark ever asked CMP to get the information from Hydro-Quebec that you needed for the minimum offer price rule calculation?

MR. BOWER: I'm not aware of anybody requesting that information specifically.

MR. SHOPE: What about generally?

MR. BOWER: No, as Doug said, I think we had conversations with CMP about what we could do, given certain information -- if we had certain information available, how that might factor into our report and the bid. And, you know, I think we said if we have cost information, we can calculate -- we could possibly calculate a MOPR estimate. And I think I testified back in December we had those conversations and, as far as I know, they didn't go any further to my knowledge.

MR. SHOPE: So just to be absolutely clear, your testimony is that, in substance, no one at Daymark ever said to CMP or to Hydro-Quebec we would like to get from Hydro-Quebec information that we can use to make the minimum offer price rule calculation?

D. SMITH: No, that's not what I said. You asked me if I asked CMP. I had conversations with HQ. We had and have discussed previously on the record that there was a phone call with HQ where we discussed what would be needed and had discussions around the potential of them delivering information to us to calculate this, with HQ.

MR. SHOPE: Okay. Oh, so you made the request for the information for the minimum offer price rule directly to Hydro-Quebec rather than through CMP.

D. SMITH: Correct.

MR. SIMPSON: Hold on just one sec. I'm sorry, Doug, that mic is extra squeaky, and I'm just trying to save our reporter's ears. It's okay for you to use that mic, but to move it back and forth each time creates a lot of extra noise in her ears. So however you want to do it, but try not to toggle it any more than is necessary. Thanks.

D. SMITH: Understood.

MR. SHOPE: Okay. Now another -- and just to be clear, you never ended up doing a minimum offer price rule calculation.

D. SMITH: That's correct.

MR. SHOPE: Now a second -- in order to conduct the analysis of whether or not there would be a capacity market price suppression benefit, another piece of information that you would need would be whether or not Hydro-Quebec actually had any excess capacity to sell and, if so, how much. Is that fair?

D. SMITH: Yes.

MR. SHOPE: Okay. And you never got -- I'm sorry, you never did -- and when I say you, I mean Daymark. Daymark never did any analysis of its own about whether Hydro-Quebec had any excess capacity to sell at least in numerical terms and the extent of that capacity, if any.

D. SMITH: Correct.

MR. SHOPE: Okay. All right. But for purposes of the analysis that you presented of the benefits of NECEC, you assumed that Hydro-Quebec would bid 1,090 megawatts of capacity into ISO New England across NECEC. Is that fair?

D. SMITH: For the purposes of the calculation of the upper end of benefits, we assumed delivery of capacity equal to the amount on the line contracted by Massachusetts was 1,090.

MR. SHOPE: And you assumed that it cleared during the first eight years -- during each of the first eight years of the project. Is that fair?

D. SMITH: Yes.

MR. SHOPE: Okay. And the 1,090 megawatt figure was not based on any analysis of actual excess capacity that Hydro-Quebec might or might not have had.

D. SMITH: Correct.

MR. SHOPE: Okay. And in fact, it's higher than the only figure that you ever got from Hydro-Quebec about the amount of capacity that it intended to bid into New England through NECEC. True?

D. SMITH: Yes.

MR. SHOPE: Okay. And sitting here today, you don't know how much capacity Hydro-Quebec could or could not bid through NECEC. Fair statement?

MR. PEACO: I guess I -- help me out with your question. Could you restate that? I'm not sure that I understand exactly what you're asking for.

MR. SHOPE: Okay. So we were just talking about how much excess capacity -- or how much capacity Hydro-Quebec might intend to offer into ISO New England across NECEC. And sitting here today, you can't say how much that would be. Is that fair?

MR. PEACO: How much they intend to offer? The only indication that we had from them as to what they might intend would be the initial conversation we had with them in May. We haven't had any conversations with them since.

MR. SHOPE: Okay. And sitting here today, you still don't have the information that you would need to know to say whether or not any such capacity that they might offer would clear the forward capacity auction.

MR. PEACO: No.

MR. SHOPE: No, okay. So sitting here today, you're actually not in a position to say that there would or there would not be a capacity market price suppression benefit.

MR. PEACO: And as we said in our report and we say that -- we haven't -- we aren't asserting that they will clear, but to the extent they clear, the magnitude of the benefits are as we computed.

MR. SHOPE: Okay. Now I want to turn to the wholesale energy market. So moving off of the capacity market, moving to the wholesale energy market. Would you agree that natural gas prices are one of the critical drivers of your modeling and of your results?

MR. PEACO: Yes.

MR. SHOPE: Okay. And would you also agree that, all else equal, the higher the price of gas, the greater the price suppression impact would be of injecting the additional hydroelectric energy into ISO New England across NECEC?

MR. PEACO: Higher gas prices would increase the value of, you know, a resource like Hydro-Quebec injecting into the market.

MR. SHOPE: Okay. And would you also agree that the gas price assumptions that Daymark used in its analysis are higher than the assumptions that were used by London Economics and by Energyzt in this case?

MR. PEACO: Yes, and I believe we discussed that in our rebuttal testimony.

MR. SHOPE: Sure. And in fact, that's one of the reasons why London Economics and Energyzt say that the wholesale energy market price suppression benefit is substantially lower than what you've calculated.

MR. PEACO: Their results were lower and that was one of the drivers, yes.

MR. SHOPE: Okay. Now, you were -- you -- the gas prices that you used started with the annual energy outlook that had been prepared in 2017 by the U.S. Energy Information Agency. Is that right?

MR. PEACO: That's correct.

MR. SHOPE: Okay. And now you -- for your analysis, you modeled the whole eastern interconnect, right?

D. SMITH: Correct.

MR. SHOPE: Yeah. So in other words, you modeled not just ISO New England but adjoining control areas like New York ISO, PJM. I mean, we could go on and on down the list, but --

D. SMITH: Correct. That's correct.

MR. SHOPE: Okay. And because you were using all of these areas, you used not only a New England gas price, but you had different gas prices in the different control areas.

D. SMITH: Correct.

MR. SHOPE: Yeah. And would it be fair to say that the reason you modeled the adjacent control areas is that New England isn't an island and so what's going on in the adjacent electric markets can have a bearing on the prices in New England?

D. SMITH: Yes.

MR. SHOPE: Okay. Now -- one of the principal inputs of your gas price assumptions was the Henry hub index projections in the AEO. Is that fair?

D. SMITH: Yes.

MR. SHOPE: Okay. And with regard to New England, you added -- you had a couple of adders that were not part of AEO but that you -- that Daymark added on top of that. Is that right?

D. SMITH: That's not quite mechanically how it worked. The New England delivered price that we used was from the AEO. It was not derived directly from the Henry hub with an adder. It effectively represents an adder between Henry hub and the New England price.

MR. SHOPE: Sure. But on top of the New England price that the AEO had, you added an adder that was created by Daymark, right?

D. SMITH: For the northern New England gas basis differential we did.

MR. SHOPE: Yeah. And you also added a peaking unit adder that was also not part of the AEO projection. Is that fair?

D. SMITH: The model that we use has several gas prices that are derived from the AEO information, two of which are adders for peak and super peak fuel use.

MR. SHOPE: Okay, but the peaker is -- the peaking adder was something that is not part of the AEO prediction -- projection, rather, for New England.

D. SMITH: To the best of my knowledge, there's no peaker forecast in the AEO, correct.

MR. SHOPE: That was something that Daymark came up with and added.

D. SMITH: That is something that our vendor has in there that we utilized.

MR. SHOPE: Okay. And London Economics criticized your use of both of those adders, the northern New England adder and the peaking adder, right?

D. SMITH: I believe that's a reasonable summation of their statement.

MR. SHOPE: Okay. All right. So -- and by the way, all of these gas markets are interconnected in the -- in somewhat the same way as the electric markets are interconnected. In other words, the price in one region can have a bearing on the price in the others. Is that fair?

MR. PEACO: Well, in the gas markets?

MR. SHOPE: Yes.

MR. PEACO: Obviously the source of gas is generally the common price. The question is what the delivered price is can vary quite a bit. So they are related to the extent that they go back to the source price.

MR. SHOPE: Yes. So in other words, there's a source price and then there can be delivery constraints depending on where you are in the -- on the pipe.

MR. PEACO: And time of delivery issues.

MR. SHOPE: Sure. Okay. Now -- so even though there's -- even though the price in New England would not specifically be the Henry hub price, price movements in Henry hub would often correlate to price movements in New England. Would that be fair to say?

MR. PEACO: The source price lays a foundation for what the delivered price is, but there are a lot of other factors of getting gas to electric generation in New England that will make it differ.

MR. SHOPE: Sure, okay. And when you're referring to source price, you're talking about Henry hub being down in Louisiana and the gas coming up the --

MR. PEACO: Yeah, Henry hub is a common source price index that is used in the industry. I think the Marcellus area is forming it as well, but both of those are remote from New England.

MR. SHOPE: Yeah. And you reported Henry hub prices in your backup data, right?

MR. PEACO: Correct.

MR. SHOPE: Okay. Now, the -- the Henry hub price in your projection starts at around $5 an MMBtu in 2023. Do you recall that?

D. SMITH: I'm sorry, if you could point me to a page? I don't keep those numbers top of mind.

MR. SHOPE: Yes, I'm sorry, I meant to say that. So it's your NECEC-5, page 14 of 98.

D. SMITH: Yes. At or around five, yes.

MR. SHOPE: Okay. And -- now by the way, the -- subsequent to your having prepared your report -- or, excuse me, subsequently to your having done your modeling back in 2017, AEO -- I'm sorry, the U.S. Department of Energy Information Agency came out with another annual energy outlook in 2018. Is that fair?

D. SMITH: Correct.

MR. SHOPE: So that post-dates your report so obviously it wasn't available to you.

D. SMITH: That's correct.

MR. SHOPE: Yeah. And the gas prices in the 2018 AEO are lower than the ones that were in the 2017 version that you used. Is that fair?

D. SMITH: I haven't looked at all of them, but certainly there are multiple price drops in that AEO that are lower, correct.

MR. SHOPE: And directionally, the price has been going down generally speaking. Is that fair?

D. SMITH: Yes. From one to the next, yes.

MR. SHOPE: Yeah. And without getting into the specifics, the price that London Economics assumed, again for 2023, was significantly lower than the $5 that you folks had assumed using the AEO. Is that right?

D. SMITH: That's my recollection.

MR. SHOPE: Yeah, okay. Now, have you looked at how the prices that you projected using the 2017 AEO compare to futures prices?

D. SMITH: No.

MR. SHOPE: Okay. Are futures prices anything that Daymark uses in its consulting work for not just CMP but any other clients?

D. SMITH: Certainly for work that's closer to current date we would look at futures.

MR. SHOPE: Okay. And when you look at futures, what futures do you look at? What source data do you consult?

D. SMITH: We have a data aggregate service, SNL, that we generally look to. We look at NYMEX or a couple sources. I --

MR. SHOPE: Do you ever look at Chicago Mercantile Exchange or CME Group?

D. SMITH: Yes.

MR. SHOPE: Okay. So you haven't -- but just to be clear, you haven't gone back to see how any of the price projections that you've made, at least for the earlier years of your study period, to see how those compare to actual market futures prices.

D. SMITH: No.

MR. SHOPE: Okay. And would I be -- would you be surprised if -- well, do you have -- so would it be fair to say you have no idea what the futures market is predicting for 2023 with regard to Henry hub prices?

D. SMITH: Sitting here right now, I do not know what that number is, no.

MR. SHOPE: Do you have any idea whether that number is higher or lower or the same as the $5 per MMBtu that you assumed when you did your report?

D. SMITH: Since I don't know the number, no, I don't know whether it's lower or higher.

MR. SHOPE: All right. Maybe if we could circulate the next exhibit.

MR. SIMPSON: John, while we're circulating the exhibit, I just wanted to give you a head's up we're approaching break time. So I want you to be able to finish this line, but at some point after that when there's a good break spot, would you let me know?

MR. SHOPE: Yes. Yeah, I just -- I will have a little bit on this line but not too much, and I think it would be much more efficient if we would continue up on this line.

MR. SIMPSON: Yeah, I agree with that.

MR. SHOPE: Okay. I'm showing you some natural gas futures quotes from CME Group, in other words formerly the -- (indiscernible) the Chicago Mercantile Exchange data, and this was just printed out for purposes of copying back on January 4. And so if we turn to I believe it's the -- starting in the third page of the exhibit, you can see quotes for 2023 starting in the middle of that page. And the prices here are monthly. Do you see that?

D. SMITH: Yes.

MR. SHOPE: Okay. And do you see that all of these prices start with $2 and then they range from -- looks like the low is about $2.52 and then the highest is, in January, $2.91?

D. SMITH: Yes, I see that. And I also see volumes of zero.

MR. SHOPE: Okay. Now, just focusing on the prices, though. Okay, so when you say volumes of zero, these prices aren't something that somebody just made up, right?

MR. PEACO: Well, they're not -- obviously not based on trades because there aren't any.

MR. SHOPE: So -- I'm sorry. You don't understand that those are settled, they're reporting the last settled trade?

MR. PEACO: That's what it states, but this also shows no volumes so --

MR. SHOPE: Okay. So it says here that it's the last settled price. So somebody traded at that price, right?

MR. PEACO: Well, presumably there would at least be a one in the volume category if that were the case.

MR. SHOPE: Yeah. That would just be for the particular day. That's -- this is reporting a trade that may have occurred the prior day or the prior week, right?

MR. PEACO: I can't tell from this.

MR. SHOPE: So given the fact that you do use futures in your business and given the prominence of the Chicago Mercantile Exchange, is it your testimony that you have no understanding of how futures prices are reported?

MR. PEACO: I'll let Doug answer the details, but I think he earlier made the comment that we rely on it in those periods where there's substantial volume that would give some comfort to the fact that this is actually a robust liquid price. But we see in most of the futures exhibits that the volume is very thin a few years out, and we tend not to rely on that as a good, robust predictor of what the market expects prices to be in those periods.

MR. SHOPE: Sure. And that's fair. But if we look at the more current periods where there are more same-day volumes, we can see that the prices are, again, starting with the $2 figure, right?

MR. PEACO: I see that.

MR. SHOPE: In other words, a lot of these prices are even less than half of the prices that you assumed in your model, albeit for 2023, right?

D. SMITH: Correct.

MR. SHOPE: Yeah. And in fact, the general trend in gas prices in recent years has been that gas prices have been going down as the Marcellus shale has exploded in production, right?

D. SMITH: Commodity price has certainly been going down, yes.

MR. SHOPE: Yeah. Okay. Now you -- so if we could circulate the next exhibit, please. Okay, yeah, so I'm just going to explain something. We have an exhibit which is actually simply a graphing of data that's -- will be in the record with -- it's -- it includes the Henry hub data that we've just circulated and then the AEO 2018 data which we've previously put into the record without objection and then also the Henry hub assumptions that were used by Daymark and also the price assumptions of London Economics. Now, the price assumptions of London Economics are subject to Protective Order 8 so the -- which most people in the room, possibly all, have access to. But my -- since we're in public session, I don't intend to ask about the specific prices of London Economics, and we do have a public version without the London Economics data.

MR. SIMPSON: Okay. Thank you for that. If we do need to get to the confidential numbers, we'll need to go into executive -- or in camera session. Hold on just one sec. John, did -- John? John Flumerfelt, sorry. Did you give the public version or the confidential version?

MR. FLUMERFELT: (Indiscernible).

MR. SIMPSON: Yeah. So could you give her -- no, no, you don't have to leave now, but I just want to make sure that you don't get access to the confidential information. They made two copies.

MR. SHOPE: You can give her the top page, John, just the top page of that exhibit.

MR. SIMPSON: That's fine. Okay, thanks.

MR. SHOPE: We weren't expecting a lot of people to show up for a discussion of gas prices.

MR. SIMPSON: Yeah, I understand.

MR. SHOPE: So just if we turn to the second page of this, if we look at that, you can see there's a graphing of the prices that Daymark used in its model based on the 2017 AEO. Then there's a graphing of those prices with the 2018 AEO. And then below that in blue, there's the -- a graphing of the LEI prices. And then below that, there's a graphing of the futures prices. Do you see that?

D. SMITH: Yes.

MR. SHOPE: Okay. And so, of all of these, Daymark is the outlier in terms of being highest prices, right?

MR. DES ROSIERS: Objection to form.

MR. SIMPSON: Sustained.

MR. SHOPE: Okay. Well, simply, Daymark has the highest prices of the four that we're discussing, right?

D. SMITH: Yes.

MR. SHOPE: Okay. And the futures prices, including for the near-term years of 2020, 2021, and so on are lower than the projections of AEO and LEI. Is that fair?

D. SMITH: Yes.

MR. SHOPE: So putting aside the out years, at least in the near terms, what the markets are saying is that the gas price assumptions that were in AEO in 2017 and AEO in 2018 and even in LEI in the report that it did this past year are too high.

D. SMITH: At the Henry hub.

MR. SHOPE: At the Henry hub.

D. SMITH: Yes.

MR. SHOPE: Okay. Now, you made the comment that you used futures in the near term, and do you -- when you have substantial trading volumes, do you always use futures when you have them in the near term?

D. SMITH: I don't think I could say always. We do a number of different types of analyses. So we certainly use them on some of our analyses.

MR. SHOPE: Would you say that if you have near-term futures prices with substantial volumes, you would generally use those instead of a -- some sort of a government projection?

D. SMITH: Frequently, yes.

MR. SHOPE: Well, I'm asking you whether you would do it more commonly than not in what I've hypothesized.

D. SMITH: Yes, I would say more commonly than not.

MR. SHOPE: Yeah. I mean, there's a general preference for market data as the source -- as the most reliable source of information, right?

D. SMITH: Frequently that's the preferred method, yes.

MR. SHOPE: I'm sorry, frequently or -- I mean, is it generally the preferred method or isn't it?

D. SMITH: If I'm looking at short-term market data for a market participant who is interested in understanding the ramifications of that market data, then yes, that would be the preferred method.

MR. SHOPE: What if you're just trying to find out what you think is most likely going to happen? Do you -- and you think you have enough trading volume, you've got market data. Do you generally then say, look, I'll use the market data rather than what some bureaucrats down in Washington put together?

MR. DES ROSIERS: Objection to form.

MR. SIMPSON: John, could you rephrase the question, please?

MR. SHOPE: Sure. You gave me an answer based on what you said your client was interested in so I'm asking you now when you're interested in it, when you're trying to find out -- when you want to get the best sense to satisfy yourself of what you think the future is going to hold, if you have futures data and you think there's enough volume, do you generally prefer that rather than an index that somebody else has prepared?

D. SMITH: If I'm trying to answer the question of what the market is likely to look at for the period of time for which there are sufficient volumes, then yes, I would use futures.

MR. SHOPE: Okay, thank you. Now, in this case, London Economics used a combination of, well, futures in the near-term years, and then in the out years, inflated at the rate of the AEO. Do you recall that?

D. SMITH: My recollection is that's -- that was what they described as one of the inputs into their model, not the outputs, but yes, I recall that.

MR. SHOPE: Yes, yes. Okay. And that's a common approach that energy market consultants take, correct?

D. SMITH: Yes.

MR. SHOPE: Yeah. And it's an appropriate approach, right?

D. SMITH: Sorry, could you say that again, please?

MR. SHOPE: It's an appropriate approach. It may not be the only approach, but it's -- you can't criticize that as an inappropriate approach.

D. SMITH: I am not offering any criticism of that approach, correct.

MR. SHOPE: Yeah. And have you ever taken that approach yourself?

D. SMITH: Yes.

MR. SHOPE: Okay.

MR. SIMPSON: John, again, I'm sorry to interrupt your flow, and I respect that. I'm also concerned about our reporter so I'm looking for a break point pretty soon.

MR. SIMPSON: I think we're just about there.

MR. SHOPE: Okay, go ahead.

MR. SHOPE: And so you say you yourself have used the approach similar to the one of London Economics where you have a long study period, you use futures for the near term, and then you use some index or modification of an index for the out years.

D. SMITH: Correct.

MR. SHOPE: Okay. And have you used that more frequently than when you have -- have you used that more frequently than simply using the index for the entire study period?

D. SMITH: I honestly can't say whether or not I've used one method more frequently than the other. I don't know.

MR. SHOPE: And is there a reason why you didn't use that method in this case?

D. SMITH: I think the project at the time was to produce a model that might represent what the evaluators would use, and we recognized that, in previous procurements, the method was to use a full gas transportation model. We weren't going -- we didn't do that. We didn't have that -- access to that so we needed to use something public, and we were doing this in advance of the time when it would be reviewed. And so we used -- and we were doing an analysis that was, at the time, for six years out and further. And so we felt like, given the type of analysis we were being asked to do, that utilizing the best publicly-available data of what a government agency saw as the market fundamentals was the appropriate choice.

MR. SHOPE: Okay. So just a quick follow up. So in other words, your choice to just use the AEO index for the entire study period rather than to do a mix of futures in the near term and index in the out years, that was really driven by the timing considerations for the Massachusetts procurement.

D. SMITH: It was driven by the nature of the modeling exercise, which included the fact that it would be utilized in a bid into the Massachusetts 83D as well as potentially a use before this Commission should that bid prove to be the winning bid.

MR. SHOPE: And just one last question. You personally, Mr. Smith, you oversee every modeling input that goes into the modeling -- goes into the model, right?

D. SMITH: With respect to this modeling effort?

MR. SHOPE: Yes.

D. SMITH: Yes.

MR. SHOPE: Okay. Good time for a break.

MR. SIMPSON: All right, let's take a break, come back at five minutes after 11:00.

CONFERENCE RECESSED (January 10, 2019, 10:50 a.m.)

CONFERENCE RESUMED (January 10, 2019, 11:07 a.m.)

MR. SIMPSON: All right, let's go back on the record. John, you may resume.

MR. SHOPE: Sure. Actually, I just wanted to follow up a little bit on our prior conversation. We talked about the fact that you more commonly use the combination of -- for a longer-term study term, a combination of futures -- gas futures prices in the near term and then some sort of projection-based approach for the out years. Have you ever used that approach in a state commission or other governmental approval proceeding? And when I say you, I mean Daymark.

D. SMITH: Not to our recollection.

MR. SHOPE: You -- and you -- now you're the head of modeling at Daymark?

D. SMITH: No, that's not correct.

MR. SHOPE: Okay. Do you supervise the modeling at Daymark?

D. SMITH: I do not supervise the modeling outside of modeling on my projects.

MR. SHOPE: Okay. But you are aware of modeling that Daymark does in other projects?

D. SMITH: I am aware that we do modeling across a wide range of projects, including many that are not mine, yes.

MR. SHOPE: Oh, I see. But you -- in other words, it's possible that other Daymark modelers have used the combination of futures in the near term and projections in the out years in other cases, but because it's not within your bailiwick to supervise, you wouldn't necessarily know whether that's the case?

D. SMITH: I cannot speak to what they're doing with first-hand knowledge, no.

MR. SHOPE: Okay. And when you say they, you're talking about the other Daymark modelers?

D. SMITH: Correct.

MR. SHOPE: Okay. And -- but in this case, if you had used the combination of gas futures prices in the near term and then AEO projections in the out years, similar to the approach that London Economics had used, that would have resulted in lower benefits, correct?

D. SMITH: Apologies.

MR. SIMPSON: Doug, we changed out the mic at break and it must be you.

D. SMITH: I'm just not going to touch -- I'm not going to touch it anymore. I don't know what futures were at the time that we were doing this modeling. So I don't know what the result would have been. Obviously futures can be fairly volatile. So there's a fair degree of possibility that it would have been -- started lower, but I don't know that sitting here today.

MR. SHOPE: Okay. So -- but you would agree that at least when Ms. Frayer did her subsequent analysis using that approach, it resulted in substantially lower benefits from the project.

D. SMITH: Her -- the London Economics model had a number of differences, including the Henry hub forecast that went into their gas modeling. The results of all those differences were substantial but lower benefits from the energy market.

MR. SHOPE: Okay. Now --

MR. VANNOY: Could I ask a question? Maybe cut to the chase here. If you're sitting in my shoes and you're trying to evaluate a whole wide range of different possible futures and you've got an energy market that's undergoing redesign right now, how would you approach this?

MR. PEACO: Yeah, no, that's a fair question. We all sitting here know that 2023 and after gas prices are highly uncertain, and we know that as well as anybody. And what we chose to do in this analysis was to pick a public and transparent one because we're illustrating one scenario of a future, both for the Massachusetts folks and for your benefit, in the application. I mean, we don't -- we're not here sitting here pretending that there isn't a possibility gas prices are as London Economics had forecast or any others, but there are also high sides. So we're dealing with gas prices being highly uncertain in the long term which we all understand. I think that the concern that we would have here is, for any of the forecasts that we've tested, and I think that London tested a relatively low one, we see significant positive energy benefits for the project. We also know that none of the analyses that we have done have included the -- what we now know as the coming fuel security component to the energy and ancillary service markets, and that will add cost to the energy market prices and will be an avenue where the project will allow -- will provide significant mitigation to what that -- whatever that price impact will be as well. And so I think that we have analysis from the various experts here that show the benefits are positive even under relatively low gas prices, and they become very important when you're worrying about fuel security or cold snap events or things like that. And so I take that as there's a range of upside. It's uncertain, but it's all upside. And so -- and even in the London case, the numbers were significant. They weren't anywhere near zero or clearly not negative.

MR. VANNOY: Thank you. And just to be fair, I'll ask the other witnesses the same question on Friday.

MR. SHOPE: I appreciate that. Looking forward to it. Now, so we've talked about the gas price as one of the drivers. Would you also agree that the assumed carbon price is one of the three primary drivers of the wholesale energy market price in New England?

D. SMITH: Yes.

MR. SHOPE: Okay. And would it also be fair to say that the higher the assumed price of carbon, the greater the price suppression benefit of the project would be, all else being -- assumed to be equal?

D. SMITH: Yes.

MR. SHOPE: Now, the price assumption that Daymark used for this project was $15 a ton going out over the years to $30 a ton in constant 2016 dollars. Is that correct? And if you'd like a reference, it would be page 49 of Exhibit NECEC-5.

D. SMITH: Correct.

MR. SHOPE: Okay. Now that carbon price that you assumed was based on a price projection that a consulting firm called Synapse had prepared back in 2016, correct?

D. SMITH: Yes.

MR. SHOPE: Okay. And the Synapse carbon price projection was based on the assumption that the Obama administration's Clean Power Plan would be going into effect, correct?

D. SMITH: I don't recall the specifics of their report, but they've done that report for a number of years and they've assumed some kind of federal carbon costs. So subject to check, I'm willing to accept that, in that particular report, it was the plan as discussed.

MR. SHOPE: Okay, well, we'd like to put the report into evidence, and there's multiple passages on that. But if you're willing to accept that the Synapse projection was based upon the Clean Power Plan going into effect.

D. SMITH: Subject to check, yes.

MR. SHOPE: Okay. So, yeah, we can -- I don't know, do you want us to distribute that now? Why don't we distribute that now just in case there's any --

MR. SIMPSON: Sure, yeah.

MR. DES ROSIERS: It may be helpful if we identify for the record some numbers on these exhibits so we can keep track of them.

MR. SIMPSON: Sure. Great idea.

MR. SHOPE: So we had -- the first one was the Henry hub -- the natural gas futures quotes from CME Group. That would be GINT-29. And then the --

MR. DES ROSIERS: That would be -- I believe there was a 29 yesterday.

MR. BARTLETT: So 29 was the report that we were -- proposed to submit that we were going to discuss today --

MR. SHOPE: Oh, that --

MR. BARTLETT: -- background.

MR. SHOPE: Oh, then we'll keep that at 29 just because --

MR. BARTLETT: Keep that at 29.

MR. SHOPE: Yeah, okay, that's --

MR. DES ROSIERS: If you don't want one, we can make this one 29. That would make it easier.

MR. SHOPE: No, no, we do. But -- and since that's how we've referred to in the record, we should stick with that. I apologize.

UNIDENTIFIED: Twenty-nine or 30?

MR. SHOPE: No, this will be 30. This will be 30. And then the graph that compares the various natural gas prices, that would be GINT-31. Okay, and so what we're -- no, it's going to be the same exhibit with a public and private version. And then we're going to do -- we'll do the Synapse report from 2016 as GINT-32. So, for example, on page five of the Synapse report under Key Assumptions it says, "This report includes updated information on federal regulations, state and regional climate policies, and utility CO2 price forecasts as well as our own analysis of the final Clean Power Plan." Do you recall that?

D. SMITH: I see that.

MR. SHOPE: Yeah, okay. Now, that was -- that report was prepared by Synapse back in 2016. Do you see that?

D. SMITH: I do.

MR. SHOPE: And specifically in March of 2016.

D. SMITH: Yes, it says updated March.

MR. SHOPE: Okay. And are you aware that a year later in March of 2017 President Trump signed an executive order to nullify the Clean Power Plan that had been put forward by the Obama administration?

D. SMITH: I am.

MR. SHOPE: Okay. And that was done before you prepared your modeling in the late summer of 2017, right?

D. SMITH: It was done concurrent with the early parts of that modeling and prior to the finalization of that model.

MR. SHOPE: When did you actually do your model runs, sir?

D. SMITH: From February through July.

MR. SHOPE: Okay. And did you revise any of the model runs as you went through the process?

D. SMITH: Yes.

MR. SHOPE: Okay. But -- so it would be fair to say that you learned the news that President Trump had nullified the -- oh, by the way, when President Trump was campaigning for office, had he announced any intentions with respect to the Clean Power Plan to your knowledge?

D. SMITH: I don't recall paying attention to his announcements at that time.

MR. SHOPE: Okay. Do you recall, once he had been elected on November 8th of 2016, giving any consideration to what environmental policies might be implemented by the new Trump administration?

D. SMITH: Yes.

MR. SHOPE: Okay. And were you aware at that time, once President Trump had been elected, that the Clean Power Plan was likely to be under challenge, if not removed completely?

D. SMITH: Certainly it was evident that it would be under challenge, yes.

MR. SHOPE: Okay. And are you specifically certain that -- actually maybe Mr. Bower's the person to answer this. Do you know specifically when the carbon price input was put into your model?

MR. BOWER: I don't recall specifically when, but it would have been in the period that Doug described, between February and June or July, probably towards the beginning of that period.

MR. SHOPE: Okay. And -- but in any event, after President Trump issued his order, you didn't go back and -- well, once President Trump issued its order, you realized that there would be implications for the carbon price. Would that be fair?

MR. PEACO: I think maybe to cut through this a little bit, we used the low case from this forecast, and the low case, as described on page four, basically assumes fairly easy compliance with the Clean Power Plan at that time. And so we went into this with very little expectation that there was going to be anything material on that. So learning that Trump was sort of reinforcing on -- towards the low case, in our mind, wouldn't lead to a need to change anything at that point.

MR. SHOPE: Okay, but --

MR. WILLIAMSON: May I interrupt here? John, are you familiar with what RGGI prices are, what the latest auction prices for CO_2?

MR. SHOPE: Yes, we do. We have those in Ms. Bodell's technical report.

MR. WILLIAMSON: Are you aware of what the prices have been in the last few years?

MR. SHOPE: Yes.

MR. WILLIAMSON: As low as they've been?

MR. SHOPE: So the -- we've used -- we have figures in the backup. It's in the range of $5, and London Economics assumed $5.50.

MR. WILLIAMSON: At the time this was done they were down around 3.50?

MR. SHOPE: Yeah, yeah.

MR. WILLIAMSON: So low was a reasonable estimate?

MR. SHOPE: Yes, yes.

MR. WILLIAMSON: Just want to let you know.

MR. SHOPE: And -- no, we're aware and that's why -- I mean, I don't want to speak out of turn, but that's why we're asking questions about price assumptions of carbon that go from 15 to $30. And so after President Trump rescinded the -- his executive -- rescinded the Clean Power Plan, you didn't go back to try to revisit the carbon price and use some -- a price that was based on the regional -- the RGGI price, R G G I, regional greenhouse gas initiative price.

MR. PEACO: I think I just answered that question.

MR. SHOPE: Okay. Okay, all right. So -- and your answer is that you didn't do that.

MR. PEACO: Right, because we were already using the low forecast in this, and we were using a third-party source for this purpose.

MR. SHOPE: Okay, so when -- are you now retracting your testimony at the technical conference that carbon price was one of the primary drivers?

MR. PEACO: No, but that was based upon our use of the low case in this forecast.

MR. SHOPE: I'm sorry, are you saying that carbon prices that are five times the market RGGI price or maybe even six times out are a low-case scenario?

MR. PEACO: It is labeled specifically as low-case scenario in the report you just presented to us that we relied on. That's what I'm referring to. Now, what current RGGI price is --

MR. SHOPE: I'm sorry, you're saying it was a -- Synapse was a low-case scenario with -- assuming a Clean Power Plan that you knew was subsequently nullified?

MR. PEACO: I just directed you to the text on top of page four that says that their low-case scenario assumes little need for compliance with the Clean Power Plan. So that --

MR. SHOPE: Who's they?

MR. PEACO: Synapse.

MR. SHOPE: Yeah. So you're saying that the Synapse projection which identifies Clean Power Plan as a key assumption nonetheless doesn't really put much importance on Clean Power Plan.

MR. PEACO: Well, let me read you the language here. "This forecast represents a scenario in which the Clean Power Plan compliance is relatively easy." And so the low case in their forecast doesn't put a lot of reliance on the Clean Power Plan.

MR. SHOPE: Well, it says that it's less costly to comply. It doesn't say it's not a factor in the carbon price.

MR. PEACO: Okay.

MR. SHOPE: Isn't that true?

MR. PEACO: That's correct.

MR. SHOPE: Okay. Now -- and did you look at the RGGI prices that were in Ms. Bodell's technical report which are Figure 11 on page 17 of the technical report?

D. SMITH: I haven't looked at them recently. I'm generally aware of where RGGI prices have been.

MR. SHOPE: Okay. So you have no basis to challenge an assumed RGGI price of $5 or $5.50 for the study period. Is that fair?

D. SMITH: Could you state that again, please?

MR. SHOPE: You don't have any basis to challenge an assumed RGGI price of between five and $5.50 on -- for the study period.

D. SMITH: I have no basis for challenging a RGGI price, but our price isn't a RGGI price. It's a price for carbon in a world in which all the New England states are targeting 80 percent reductions by 2050 which is not that many years after the end of this study period. The carbon price, there may be a lot of mechanisms that lead to that. The existence or non-existence and the current price or non-price of any one of those in my mind is not necessarily indicative of where the cost of carbon and the marginal cost of carbon for emitting -- for electric generation will be over that study period.

MR. SHOPE: Okay. So in other words, your assumption is that the -- there will be additional regulations that may be promulgated by the various New England states that would result in an increase in the price of carbon. Is that fair?

MR. PEACO: Well, more importantly there's existing --

MR. SHOPE: Could you just answer my question, please?

MR. DES ROSIERS: Objection.

MR. SIMPSON: All right, everybody take a breath. Thank you. Could you please rephrase the question.

MR. SHOPE: Yes. And this is really following up on Mr. Smith's comment. Are you assuming that the New England states will be adopting additional regulations above and beyond RGGI and above and beyond the Massachusetts statutory mandate that will increase the cost of carbon?

D. SMITH: No, not exactly. The price built in assumes some more stringent caps, and the resulting pricing impacts, whether it's state-driven or federal, whether it's regional, that was not our concern. Our concern was to attempt to capture a reasonable estimate of the cost of emitting a metric ton of carbon out over a 20-year period that wasn't starting for five or six years from the time that we were modeling so, therefore, going out 25 plus years in a world in which there are significant commitments to drastically reduce carbon emissions.

MR. SHOPE: All right. Now, in New England, there are going to be significant new renewables that are coming on -- that will be coming online, for example, the offshore wind projects. You're aware of that?

D. SMITH: I am aware of the offshore wind projects.

MR. SHOPE: Yeah. And those new additions of renewables to the fleet are actually going to have a tendency to push down the price of carbon, correct?

D. SMITH: By themselves, without any other considerations, yes, those will tend to push down the price of carbon.

MR. SHOPE: Now -- and in fact, the more renewables that are added to New England, putting aside NECEC, the lower the price suppression impact of NECEC will be. Is that fair?

D. SMITH: It really depends on where we are in the supply stack as the questioning earlier on was. So I think you'd have to model those cases to know for certain. There'd be a lot of additional changes as the supply mix continues to change. There is also potential impacts on demand as we consider electrification of heating and transportation that are not considered. There's many changes coming, not all of which are easy to model sitting here today, that could move the price of carbon and the benefits of a project like NECEC in directions that are -- that represent a wide range of potential outcomes.

MR. SHOPE: Well, you're not just throwing up your hands and saying there's nothing I can do, are you?

D. SMITH: No, I'm producing a model that I believe is a reasonable representation of a potential future within that range of uncertainty and illustrating the potential benefits that come along with that. And on this record, we have a number of other models with differing assumptions and differing levels of benefits.

MR. SHOPE: So then turning to the modeling, in your modeling world, all else being equal, if you add another renewable generating source that's bidding power into the pool at a zero price, that is going to depress -- have a tendency to depress the price of energy at the wholesale level in New England. Is that true?

D. SMITH: All else equal, which is not a hypothesis that I'm comfortable with, but under that hypothetical, all else equal, it would tend to decrease benefits.

MR. SHOPE: Okay. Now, your model does not build any new renewables in New England, even if it would be economic to do so. True?

D. SMITH: We build the 83C offshore wind as scheduled by the Massachusetts legislative. We assume that all of those procurements are made.

MR. SHOPE: Okay, but you do not assume that any other projects get built based on -- any other renewable projects get built based on economics. Can you just answer that yes or no at least to start?

D. SMITH: We build the tristate, the 83C, and additional solar and nothing beyond that.

MR. SHOPE: Okay, let me just -- we really need to get a clear answer on this question. You have a buildout model -- first off, you don't use the buildout model that comes with the Aurora program that you've bought off the shelf, right?

D. SMITH: Correct.

MR. SHOPE: Yeah, you have your own proprietary model. Is that fair?

D. SMITH: That is correct.

MR. SHOPE: Okay. And so with that model that you used -- and that model requires operator intervention, or at least permits operator intervention, right?

D. SMITH: Yes.

MR. SHOPE: And in fact, operator intervention is something that you engage in.

D. SMITH: Yes.

MR. SHOPE: Okay. And so when you were modeling how new plants got built out, you intervened or someone at Daymark intervened to prevent the buildout of renewables other than the ones specified, even if those other renewables would have been economic to build. Isn't that true? Isn't that what you testified before at the technical conference?

D. SMITH: It would take intervention to build those in our model, and we did not intervene to build additional renewables.

MR. SHOPE: So if there were a high carbon price, that would tend to make renewables more likely to be economic, correct?

D. SMITH: Yes.

MR. SHOPE: Okay. And your modeling did not cause that process to occur simply as a matter of the software. You had somebody go in and dictate what was going to be built and what wasn't going to be built. Right?

D. SMITH: No, the model assumes that as capacity is short in the region, it's met by combined cycles or combustion turbines.

MR. SHOPE: Not renewables.

D. SMITH: Correct.

MR. SHOPE: Okay. And even though you are expecting that there -- or you mentioned earlier that there are all these policy plans for reducing carbon emissions, your model and your intervention didn't build out the renewables in order to meet the interim carbon emissions targets that had been established by Massachusetts and Connecticut. True?

D. SMITH: Yes.

MR. SHOPE: Okay. And you didn't do that in order -- and you didn't build out renewables in New York to adjust for New York's stated policy plan of having 50 percent renewable generating sources by 2030.

D. SMITH: Correct. The modeling exercise was not intended to look at the full cost of meeting these targets. It was to look at the benefits associated with a single project within that greater procurement that will be going on.

MR. SHOPE: Okay. And so if you -- but if you had chosen, through the operator intervention, to build out renewables in order to satisfy the New York plan of 50 percent renewable sources by 2030, the Connecticut interim carbon emissions targets, the Massachusetts targets, that would have educed the benefits of NECEC in relation to the benefits that were put out by your model.

D. SMITH: If I was going to --

MR. SHOPE: Could you answer yes -- could your answer start by answering that yes or no?

D. SMITH: No. If I needed to consider the ramifications of those policies in terms of the supply balance over the course of that 25 years, I would need to consider not only what might get built but also what future demands might look like from those policies as well. And the final outcome of that would depend on a modeling exercise and an investigation into the likely outcomes of both sides of that equation, not just one.

MR. SHOPE: I'm sorry, using the likely demands, you're talking about the likely size of load growth?

D. SMITH: Yes, as one additional input I would consider.

MR. SHOPE: So you're telling me that sitting here today, you have no idea whether or not adding more renewables to the model -- so in other words, if we were to -- if you were to intervene in your buildout in a different way than you did and you had added more renewables, you have no idea sitting here today whether or not that would have -- that -- doing so would increase or reduce the benefits calculated for the NECEC project.

D. SMITH: That's not what I said.

MR. SHOPE: Okay, so could you please answer that question?

D. SMITH: I believe I did answer that question. In the hypothetical where all we do is add additional renewables, that would tend to reduce benefits.

MR. SHOPE: Okay. And in this case, your intervention chose not to do so.

MR. PEACO: I think the better characterization of the analysis that we did do was NECEC is a winner in the competition amongst a lot of the alternative renewables that would have -- that are in the marketplace today and is the lowest cost. And what we presented as analysis is taking those renewables that are already existing or committed through some other means, some other policy, what is the incremental change in the marketplace adding the next most economic, which is the NECEC which is the winner of this auction, as they are. Once you've added that, you can then look at the incremental benefits of adding other more expensive renewables in the market over time, but that was not the purpose of this analysis. The purpose of this analysis was to show what's the impact in moving towards those goals of adding the next most economic resource, which is NECEC by virtue of winning the bid.

MR. SHOPE: Mr. Peaco, NECEC was not part of your base case.

MR. PEACO: Correct. The whole purpose of our analysis was to show what happens when you add that to the base case.

MR. SHOPE: Yeah. And your base case, like your project case, did not build out the other renewables, right?

MR. PEACO: Right, because they've proven in the RFP not to be as cost effective. And so the purpose of our analysis was to test the impact of adding the next resource.

MR. SHOPE: Let me ask Mr. Smith. Mr. Smith, do you think it's appropriate in the -- for the base case to assume that NECEC is the winning project?

D. SMITH: Yes, that was the purpose of the modeling exercise was to illustrate the benefits that would occur if the project was selected.

MR. SHOPE: No, my -- let me repeat my question. For purposes of modeling the base case -- the base case is the case without NECEC coming into existence, right?

D. SMITH: Apologies. It's not appropriate to assume any winning project, and we did not assume any winning project, in the base case.

MR. SHOPE: Okay. But the base case did not build out the renewables to comply with the targets for renewables and carbon emissions that have been set in Connecticut, Massachusetts, and New York, right?

D. SMITH: Which -- correct, which would have presumed winners that I just said would not be appropriate for the base case.

MR. SHOPE: Okay. All right. Now, when you modeled the project case -- so we're switching back to the project case, not the base case anymore. When you modeled the project case, you modeled an injection of 9.5 terawatts of energy coming into Lewiston, Maine. True?

D. SMITH: No, that's not true. We didn't know what the final -- we didn't know what the actual bid was so we used a proxy, and the amount of energy was 981 megawatts in each hour of the year.

MR. SHOPE: Okay. Did you also do a case that involved 1,086 megawatts?

D. SMITH: Correct. That was the case with the project plus the economic flow of the 110.

MR. SHOPE: Is that almost 9.5 terawatts?

D. SMITH: It's close, yes.

MR. SHOPE: Terawatt hours, excuse me. So in that case -- and that's where your modeling essentially -- well, the ultimate contract was for 1,090 megawatts, right? Or set of contracts.

D. SMITH: The -- my understanding is the TSA is for 1,090 and the PPAs are for 9.45 gigawatt hours -- terawatt hours of energy.

MR. SHOPE: So that's pretty close to that second case that you modeled.

D. SMITH: The 1,086 is close to what was finally selected, yes.

MR. SHOPE: Sure, okay. And that -- but that energy in your model shows up in Lewiston. But in your model, it doesn't come from anywhere else. Right?

D. SMITH: It is modeled as an injection into central Maine zone.

MR. SHOPE: Okay. But you also modeled Quebec, right?

D. SMITH: Yes.

MR. SHOPE: Okay. And you didn't model the roughly 9.5 terawatt hours that were coming into Lewiston as -- and this is for purposes of modeling -- as coming out of any generators in Quebec.

D. SMITH: We did not increase the amount of generation in Hydro-Quebec and put a link between there and Maine. We took the shortcut of simply putting the generation in Maine.

MR. SHOPE: Okay. And so that effectively had the increase -- that had the effect, for modeling purposes, of adding an additional 9.5 terawatt hours of energy to the northeastern United States and eastern Canada.

D. SMITH: It was equivalent to putting that in Hydro-Quebec and putting a line there which would have increased total generation available. Final generation for the model would be based on load so the total amount of generation would not have changed.

MR. SHOPE: All right, so let me just be clear. By injecting that power into -- the 9.5 terawatt hours into Lewiston but not taking it away from anywhere else, the net effect in the modeling was to increase the supply of energy in the northeast United States and Canada by 9.5 terawatt hours. True?

D. SMITH: Yes, supply is increased by 9.45 or thereabouts.

MR. SHOPE: And so would it be fair to say that if you increase the supply of something and keep everything else equal, the effect of that is going to be to reduce price?

D. SMITH: It's -- yes.

MR. SHOPE: Yeah, that's the law of supply and demand, right?

D. SMITH: Correct.

MR. SHOPE: Okay. So as a consequence to that, would it be fair to say that if you had -- instead of just injecting the power in Lewiston and not taking it out of anywhere from Canada, but instead, you had assumed that the power had to come from Quebec and, therefore, couldn't come -- go from Quebec to somewhere else but had to go to Maine, that would have reduced the benefit -- the price suppression benefit.

D. SMITH: Let me make sure I understand your question. You're saying if we assumed delivery of nine -- roughly 9.5 terawatt hours of energy into Maine without a commensurate increase in supply anywhere, would that change the benefits.

MR. SHOPE: Yes.

D. SMITH: Yes, it would.

MR. SHOPE: Yeah. In other words, if you had assumed that Hydro-Quebec was currently selling that 9.5 terawatt hours somewhere else and it had -- and in order to serve this line and the Massachusetts contracts, it had to divert that power, if you had made that assumption, that would result in smaller project benefits. True?

D. SMITH: Because all of the regions are interconnected, I can't know for certain what that would do. We have two Energyzt runs, one of which did exactly that and one of which modeled it the way we did that gives us an indication that the benefits in their case were somewhat less but still substantial.

MR. SHOPE: Okay. And in your case, the delta between the complete injection -- we'll call it the diversion versus the injection cases, the delta's even greater, right?

D. SMITH: I'd want to run that to answer that. I -- we didn't do that case. I have no basis for speculating on what it would be.

MR. SHOPE: So after this issue was raised, you went back and you looked at the Energyzt numbers on the diversion case versus the injection case and you just testified to that, right?

D. SMITH: Yes, we reviewed those.

MR. SHOPE: But you never went back to look at your own numbers to see what would be the effect of using a diversion approach rather than an injection approach.

D. SMITH: We didn't model that case so I have no numbers to look at.

MR. SHOPE: Okay. So your model -- just to be straightforward about it, your model assumed no diversion whatsoever. Correct?

D. SMITH: Our model models economic -- no. Our model has economic transfers between zones --

MR. SHOPE: I'm sorry, I'm talking about with respect to NECEC. Your model --

MR. DES ROSIERS: If I can object, the witness was in the middle of his answer.

MR. SHOPE: I was trying to clarify my question.

MR. SIMPSON: Yeah, no, I understand that. So let's just start over again and ask the question. Thanks.

MR. SHOPE: Yeah, and I apologize for interrupting. I just wanted to try to save everybody's time because I understood you were giving a fair answer to the question as I had phrased it. So I want to rephrase it in particular.

MR. DES ROSIERS: I always like my witnesses to be allowed to complete their fair answers to questions.

MR. SHOPE: Your model assumes that the nine -- roughly 9.5 terawatt hours that gets added in Lewiston does not get diverted from anywhere else? Is that fair?

D. SMITH: No, I can't say that with certainty because what flows out of Hydro-Quebec in our model is on the basis of economics. So it is -- it's possible that some amount less flowed in the NECEC case.

MR. SHOPE: Okay, but didn't you testify before that your -- the flows and the generation out of Quebec didn't change when you added NECEC?

D. SMITH: If that was the impression I gave, then I certainly misspoke. The other interfaces are identical in both cases. They are available to flow, and they flow on the basis of economics.

MR. SHOPE: Okay, but let me -- let's -- maybe we'll break it down. When you modeled, in the modeling that you did between your base case and your project case, Quebec generation was the same in both cases. True?

D. SMITH: Quebec capacity was the same in both cases. Generation is an energy figure. I'm trying to make sure we're clear about concepts here.

MR. SHOPE: Sure, sure. The terawatt hours of generation in Quebec did not change in your model between the base case and the NEC (sic) case. True?

D. SMITH: I have not looked at that. But that would be surprising to me because the energy that is generated in Hydro-Quebec and flows to the various regions is on the basis of economics. The economics change when the NECEC is in. So it would be surprising to me if there were no changes in flows.

MR. SHOPE: Okay. Did the flows across markets change?

D. SMITH: Could you clarify what you mean by markets?

MR. SHOPE: All right, let me ask a different question because I think it's already been answered -- I want to make sure your understanding is the same as it was in previous testimonies. In between your base case and your project case, did the exports of power -- and I'm sorry, exports of energy, so I'm speaking now of energy -- did the exports of energy from Quebec change other than the fact that NECEC appears?

D. SMITH: The output flows of energy from Hydro-Quebec to the other regions --

MR. SHOPE: In total.

D. SMITH: -- in total may have changed. I don't have the numbers in front of me. We didn't -- I didn't look at that. All I can tell you is we didn't change how we modeled each of those interfaces. They had the same capability to flow at the same price. But since the economics change and since the model allows them to flow on the basis of economics, it is likely that, to at least some small extent, the flows out of Hydro-Quebec changed.

MR. SHOPE: In other words, you're saying that the flows might have changed just because nine and a half terawatts appear in Lewiston.

D. SMITH: I'm saying that if nine and a half terawatt hours of energy flows from Hydro-Quebec into central Maine, that will change prices throughout the region. Many generators, including Hydro-Quebec, all generators including Hydro-Quebec, will respond to changing prices and may flow different amounts of energy, generate different amounts of energy in response to that.

MR. SHOPE: Okay. I really need to break this down a little -- into little bits. The amount of generated terawatt hours in Quebec did not change between the base case and the project case. True? And maybe Mr. Bower is more familiar with this. Maybe he can answer that question.

MR. BOWER: As Mr. Smith said, we haven't looked at that so I'm not sure. It is possible that generation changed. Those numbers were provided in ODR 13-10. So it's on the record.

MR. SHOPE: Okay. And in the -- did the load in Quebec change in between the project case and the -- in between the base case and the project case?

MR. BOWER: No, the load did not change.

MR. SHOPE: Okay. And did the exports from Quebec -- just putting NECEC to the side, did the exports from Quebec in total put aside which other control area they went to? Did the exports in Quebec in total change between the project -- between the base case and the project case?

MR. BOWER: We have not looked at that so I can't say for sure, but it is provided in ODR 13-10.

MR. SHOPE: Okay, so when you say you can't say for sure, do you have any sense whatsoever of the order of magnitude of any change in the total exports, disregarding NECEC?

D. SMITH: I'm really trying to be helpful here. I suspect the magnitude is small.

MR. SHOPE: Okay.

D. SMITH: But -- and I also suspect it's not zero. So somewhere between zero and small is likely to be answer.

MR. SHOPE: Is small like a tenth of a terawatt hour?

D. SMITH: I cannot give you a better answer than what I've given you.

MR. SHOPE: Is it a rounding error, sir?

D. SMITH: No, it's a change in flows due to changing economics.

MR. SHOPE: Now, so other than this small change that you mention -- well, but there is no -- your analysis did not assume diversion, right?

D. SMITH: With assume, I take that to be as an input so, no, it did not -- there was no assumption a priori that there would be diversion or that it had to occur.

MR. SHOPE: Okay. Now -- and so you never modeled any kind of diversion with respect to this project.

D. SMITH: In our modeling, we did not force diversion.

MR. SHOPE: Okay. Now -- well, you wrote in your rebuttal testimony that an incorrect -- that it was an incorrect assumption that NEC (sic) energy would -- it was an incorrect assertion that NECEC energy would be energy diverted from existing exports to New York. Do you recall that?

D. SMITH: Yes.

MR. SHOPE: Okay. And you also wrote that the hydro power will be incremental to historical baseline exports. Do you also remember writing that?

D. SMITH: Yes.

MR. SHOPE: Okay. Now -- and you said that there's one possible exception to the NECEC generation being fully incremental, that one possible exception is that a small reduction in exports from Hydro-Quebec to Ontario could occur. Do you recall writing that?

D. SMITH: Yes.

MR. SHOPE: Okay. Now, the only information that you had from Hydro-Quebec on the issue of diversion was that there would be substantial diversion. Isn't that true?

D. SMITH: No, I don't agree with that characterization.

MR. SHOPE: Do you recall receiving a memo from Hydro-Quebec --

D. SMITH: Yes.

MR. SHOPE: Okay. So at the time that you wrote your report, the only information that you had from Hydro-Quebec about whether or not there was going to be a diversion was a memo that said that there was going to be substantial diversion, including from New York.

MR. DES ROSIERS: I'm going to object because now we're going into the contents of the confidential document which is -- needs to be done in confidential session. I will also object as it misstates evidence in the record.

MR. SHOPE: My intent was not to go into the specific numbers, and I believe that we had -- when we had done this in technical conference, we had used a number X. And so, therefore, on that basis, I was going to proceed.

MR. DES ROSIERS: I guess I would object to the characterization of the words in the page without using the words on the page. If you're going to do it simply with assumptions without characterizations that would imply the contents of the document, we'll have to take that -- or I'll reserve my objection one by one but --

MR. SIMPSON: I'm wanting to see if you can proceed, John, without going into in camera session, but if we need to do that, we will. And we'll revisit the objection at that time.

MR. SHOPE: Yes, and I am mindful of the confidential issues, but I'm also mindful of the strong preference for proceeding in public session given the public interest in this matter.

MR. SIMPSON: You're exactly right, and I appreciate that.

MR. SHOPE: As of the time you wrote your report for this Commission which was submitted in the fall of 2017, did you have any information from Hydro-Quebec that there would not be diversion, at least some diversion?

D. SMITH: I -- no, I do not believe that the communication that you're referring to is -- with respect to our modeling represented an indication of diversion.

MR. SHOPE: Let me try to make this as simple as possible. Before your report -- before you submitted your report in the fall of 2017 in support of this project, nobody from Hydro-Quebec, in substance, had ever communicated to you that when it supplied energy across NECEC, it would not be diverting any of that from other markets. Nobody from Hydro-

Quebec ever said that, isn't that right?

D. SMITH: I'm struggling to answer without referring to the details of the one communication that I had.

MR. SHOPE: Okay, so the communication that you referred to -- you're referring to a memorandum in May from Mathieu Le Blanc at Hydro-Quebec, right?

D. SMITH: An email, yes.

MR. SHOPE: Yeah. And -- but it was an email that was a substantive email, that wasn't just hi, have a nice day.

D. SMITH: Correct.

MR. SHOPE: Yeah. And that email indicated that there was going to be substantial diversion of the energy that was going to be sold across NECEC, substantial diversion from other markets. True?

MR. DES ROSIERS: Same objection. Now we're going into the contents of the memo. If we're going to ask about, it should be done, but it needs to be done in confidential session so the witness can then answer based on the communication in complete form.

MR. SHOPE: So confidentiality, in my view, relates to things that are truly business proprietary, and simple -- the issue of whether there will or will not be diversion doesn't rise to that level. Specific numbers may, but the general topic does not. And in fact, the general topic has been discussed extensively in the press by Hydro-Quebec, Hydro-

Quebec making all sorts of public assertions that there will be no such diversion. And we're -- I think it seems to me that at this point, Hydro-Quebec cannot insist that its contrary statements be subject to some sort of confidentiality order.

MR. SIMPSON: Objection's overruled. Please answer the question.

D. SMITH: Could you restate the question, please?

MR. SHOPE: The only communication you had from Hydro-Quebec on the subject of diversion of energy that would be sold across NECEC from other markets, so whether the energy sold across NECEC would be diverted from other markets, was that a substantial portion of it would be so diverted. Isn't that right?

D. SMITH: The memo that we received posited two futures, the combination of which involved different amounts flowing to regions other than New England.

MR. SHOPE: In other words, it posited that there was some diversion, true?

MR. PEACO: I guess I disagree with that unless you -- if you're using diversion the way I understand that you've used it in the past, I would disagree with that. We understand the memo to say they expected to have additional amounts of energy than they have had historically and they had ways to think about how to distribute that energy in the event that they had NECEC and ways that they would have to distribute it if they didn't have NECEC. But in no instance were they indicating that they were not going to have additional energy from historical baseline and that they were diverting existing sales from other markets to this market.

MR. SHOPE: Didn't the figures show that the sales to some of the other adjoining areas were going to be declining once NECEC came online?

MR. PEACO: That was based upon the premise that they were starting with an incremental amount of energy. And I think that's where we part company on our understanding of the numbers.

MR. SHOPE: Isn't it true that the incremental amount of energy that was posited in that memo from Mathieu Le Blanc in May of 2017 was not -- was substantially less than the full amount of energy of terawatt hours that would be delivered across NECEC? Isn't it true, sir?

MR. SIMPSON: I'm sorry, we were talking off mic.

MR. PEACO: I'm not sure that we're getting into --

MR. SIMPSON: It strikes me that this is artificially contorted here, and I think the most efficient thing would be to do this in confidential session. I appreciate the effort to avoid doing that, but I also want to get copies of the email for the Commissioners so that they can follow on and we don't have that now. So if -- John, you can pursue this for sure, but let's do it in confidential session and when the

Commissioners have a copy of it in front of them.

MR. SHOPE: That's perfectly fair. And let me just follow up on this because I think these are questions that can and should be asked in public session which is I understand that you -- well, putting aside whether you think diversion should or should not be assumed, if you had assumed that some or all of the energy that Hydro-Quebec was going to be selling across NECEC was diverted from other markets, that would have reduced the price suppression benefit that you found. True?

D. SMITH: Yes, I would expect reduced benefits if there was reduced supply in the region.

MR. SHOPE: Now, one of the other markets that Hydro-Quebec sells into is New York. Is that your understanding?

D. SMITH: Yes.

MR. SHOPE: Okay. And your model included modeling of exports from Hydro-Quebec into New York.

D. SMITH: Yes.

MR. SHOPE: Now, for purposes of your modeling or otherwise, you haven't done any analysis of how diversion of those exports out of New York into New England across NECEC would cause the gas or other fossil fuel plants in New York to fire up, right?

D. SMITH: No, we've done no such analysis.

MR. SHOPE: Okay. But again, putting aside whether you think it's proper to so assume, if you had assumed that there would be diversion of hydro exports from Quebec into New York, into New England, that could cause gas plants in New York to start firing up to backfill the supply, right?

D. SMITH: New York state has -- no, I don't necessarily believe that follows. New York has target emission levels, and so what would happen in a hypothetical future in which imports from Hydro-Quebec were not occurring is something we'd have to analyze and think about what the response might be in New York isn't --

MR. SHOPE: So over the longer term, you're saying we don't know what kind of new plants might get built in New York to make up from the reduction in hydro supply from Canada. Fair?

D. SMITH: Yes.

MR. SHOPE: Okay. In the shorter term -- so there's the day before the contract goes into effect and then there's the day after --

D. SMITH: In the shorter term, whatever was marginal would generate more.

MR. SHOPE: Okay. And in New York, that's -- it's frequently a gas plant that's marginal, right?

D. SMITH: That's my understanding, yes.

MR. SHOPE: Okay. And if there's increased demand for gas in New York, that would tend to increase the price of gas in New York. True? Other things being equal.

MR. PEACO: Did you mean the price of gas or price of electricity?

MR. SHOPE: Price of gas.

D. SMITH: All else equal, yes.

MR. SHOPE: Okay. And if the price of gas in New York goes up, that, all else equal, tends to cause the price of gas in New England to go up as well. Right?

D. SMITH: Yes.

MR. SHOPE: And that's because the gas systems in New England and New York are interconnected through the Iroquois and other pipelines.

D. SMITH: Correct.

MR. SHOPE: Okay. Now, if you wanted to understand all of those connections, you would want to have a natural gas pipeline model, right?

D. SMITH: To model that, yes, you'd want a gas transportation model.

MR. SHOPE: And you didn't know -- you didn't use a gas pipeline model for this case.

D. SMITH: Correct.

MR. SHOPE: Okay. And now you did testify that -- well, if you didn't do a gas pipeline model, then you don't know -- in the scenario where there is diversion, you don't know what the effect of those additional gas plants in New York firing up would have on, at least in magnitude, the gas prices in New England, right?

MR. PEACO: We've already indicated we didn't do a diversion case.

MR. SHOPE: Yeah, I understand that.

MR. PEACO: But your question was --

MR. SHOPE: If you -- so -- but let me just -- you're right. Let me make it simpler for you. If we accept the hypothesis that switching the hydropower from New York to New England causes more gas plants to fire up, you didn't do any kind of analysis of what sort of effect that would have on gas prices in New England other than, all else being equal, you understand that it would tend to make the prices go up. Right?

D. SMITH: Correct.

MR. SHOPE: Okay. So if we're talking about a cold winter day such as we were -- or a cold winter week or a cold winter two weeks such as we were discussing yesterday with Mr. des Rosiers and Ms. Bodell, would it be fair to say that you don't know -- if the hydropower gets diverted from New York to Massachusetts and the New York gas plants fire up, you don't know what effect that's going to have on the gas price in New England other than it's going to go up?

MR. PEACO: I guess let me make sure I understand the question. You asked about a cold snap?

MR. SHOPE: Yeah.

MR. PEACO: So help me understand a little bit more about what the specific question is different from what you've already asked.

MR. SHOPE: Okay. Well, as I understand your testimony, you believe that NECEC is going to provide some sort of price protection in the case of cold snaps in New England. Is that fair?

MR. PEACO: Yes.

MR. SHOPE: Okay. And that's because there's going to be less demand for gas in New England if the hydropower's coming in. Is that fair?

MR. PEACO: Yes.

MR. SHOPE: Okay. But if we were to posit that another effect of NECEC is to cause gas plants in New York to fire up more than they would because they have to make up for hydropower that got diverted, you haven't analyzed the extent of the gas effect price in New England -- gas price effect in New England.

MR. PEACO: We have done no diversion analysis. I think we've said that before.

MR. SHOPE: But it's quite likely that if you did such an analysis, you would see that there might be no hedging effect or a lesser hedging effect --

MR. PEACO: Well, I think in your postulate, I think you would see a hedging effect. Not that I accept your premise on diversion, but even in that case, New York is not nearly as constrained on natural gas pipe supply as New England is. And so in a cold snap, the New England prices for gas delivered to plants are going to be much higher than in New York. So there would be a hedge --

MR. SHOPE: So your view is that there would be some hedging effect but maybe not to the same magnitude as what you've postulated, assuming diversion which you don't agree with.

MR. PEACO: Yes.

MR. SHOPE: Okay.

MR. PEACO: I didn't say they're not to the same degree. I don't know what it would be, but it would be significant because there is a significant price -- gas price differential in exactly those conditions.

MR. SHOPE: Now, your assumption that there's some sort of a hedging benefit from the hydropower that's going to be sold under the power purchase agreements with the Massachusetts utilities assumes that the 1,090 megawatts are going to be flowing without interruption 24 hours a day, 365 days of the year, right? That's how you modeled it?

D. SMITH: The base change case was obviously 365. Some of our sensitivities were for shorter periods, but it was assumed that the amounts per hour were in all hours.

MR. SHOPE: Okay. So in other words, you didn't assume when you did your hedging benefit analysis that, on those -- during those cold snaps, it would be cold in Canada as well, Quebec would need the hydropower to heat homes in Quebec, and Quebec would use contractual opportunities to produce the supply to New England. You didn't assume that, right?

D. SMITH: We didn't assume that increased load on the -- for Hydro-Quebec distribution would alter Hydro-Quebec Production's delivery under the contract.

MR. SHOPE: Yeah, so just to put it in layman's terms, you assumed that even if Quebec needed the power to heat its own homes and it had the contractual ability to reduce the delivery to New England, nonetheless it wouldn't do that.

MR. PEACO: We assumed the construct that is in place in Quebec today which Hydro-Quebec Production has a fixed obligation to supply a fixed amount of energy to HQD and that, beyond that, HQD is on their own to secure supplies and that their contractual commitment under this agreement would be the same or no different than the contractual commitments between Production and Distribution.

MR. SHOPE: Now, and when you did your modeling, you obviously -- back in 2017 you didn't have access to the final versions of the power purchase agreements as they were executed and submitted to the Massachusetts Department of Public Utilities, true?

MR. PEACO: Right.

MR. SHOPE: Yeah. So you -- when you -- okay, I think you've answered that question. Mitch, I'm -- or rather, Chris, I'm at a logical break point so I don't know if you want to -- but let me know whether you want to break for lunch.

MR. SIMPSON: Okay. Do you have more public questions?

MR. SHOPE: I do.

MR. SIMPSON: Can you give me an estimate for how much more you have?

MR. SHOPE: Maybe 20 minutes? I don't know, let me just -- hold on a second.

MR. SIMPSON: Yeah.

MR. SHOPE: There is a practical question which -- issue which is we may want to generate an exhibit to question them about it. So that will be more easily done, you know, during a lunch break. But what I can do is, if you'd like just because it's a little early, I can keep going and then if we can just come back on that one --

MR. SIMPSON: Well, I'm not opposed to breaking for lunch now. I'm just trying to get an idea of how much --

MR. SHOPE: I think actually -- I think the logical thing is for me to keep going, and then we can take break, I can come back, finish up in public, and then we can go on.

MR. SIMPSON: Okay, let's do that.

MR. SHOPE: Now, your model, generally speaking, other than the operator interventions that we've talked about with capacity, would you say otherwise you're trying as much as possible to have economic modeling of the outputs once you've put in your assumptions?

D. SMITH: Yes.

MR. SHOPE: Okay. Now, however, it's the case that, with respect to the Maine biomass plants, you did not model their output economically. Is that correct?

D. SMITH: They were economic but with a very low fuel price that led to a very high dispatch.

MR. SHOPE: I'm sorry, they're what?

D. SMITH: They're modeled economically but with a low price such that they run as -- effectively as base.

MR. SHOPE: In other words, they run quite a lot of the time.

D. SMITH: Yes.

MR. SHOPE: So in other words, the fuel price that you assumed is very low.

D. SMITH: Yes.

MR. SHOPE: Okay. And the -- now, you're anticipating that once NECEC comes in, the wholesale energy market price is going to drop in a way that you say generates substantial savings for Maine ratepayers. True?

D. SMITH: That's the results of our model, yes.

MR. SHOPE: Yeah, okay. And that price reduction would tend to reduce the dispatch of the biomass plants if they were being modeled economically, right?

D. SMITH: They were modeled economically. Given the assumptions used, it didn't lead to a change in dispatch.

MR. SHOPE: Okay. Do you recall testifying that you -- that the plant assumed that the biomass plants would not change their operations with or without NECEC?

D. SMITH: I don't specifically recall that. That was the outcome of the model runs.

MR. SHOPE: They weren't fixed?

D. SMITH: To the best of our recollection, they were not fixed. I don't recall all the modeling details of all the generators operated, but that's my best recollection sitting here today.

MR. SHOPE: Okay. Is the -- does the low price that you assumed have the effect -- the same effect as fixing?

D. SMITH: Within a wide range of energy price outcomes, it would have a similar effect, yes.

MR. SHOPE: Do you know what the price -- the basis was for the price that you used for the biomass plants?

D. SMITH: My best recollection -- this -- let me clarify. This was not an assumption that was changed for these model runs. My best recollection is that there was an assumption that they would have offsetting req revenues such that they would attempt to bid and run to realize a net fuel cost that was low. I believe that was the original rationale.

MR. SHOPE: Now, I think we mentioned -- we discussed before that you don't use -- but generally speaking, your model is drawn -- taken from Aurora which is an off-the-shelf model, right?

D. SMITH: That's the base of our model, yes.

MR. SHOPE: Yeah. But Aurora offers a retirement and buildout module, but you don't use that.

D. SMITH: Correct.

MR. SHOPE: Okay. And you use your own proprietary capacity market model with operator intervention. Is that right?

D. SMITH: We use our own proprietary model that can and often does involve some intervention, yes.

MR. SHOPE: And there was intervention in this particular case, right?

D. SMITH: To identify exactly what units would retire in cases where they were close and then a determination of the split of combined cycle and CTs, there was intervention in both those cases.

MR. SHOPE: Okay, now -- and by the way, the determination of how many units or which units retire has an effect on price reduction, right? Energy market price reduction.

D. SMITH: Yes, it changes supply in the region and, therefore, changes prices.

MR. SHOPE: So -- and the more units tend to retire, other things being equal, there's less price suppression that would result from NECEC, right?

D. SMITH: I'm not sure that I would agree with that. I think it would depend on what it would do to the supply stack and where New England would be in the supply stack.

MR. SHOPE: Well, so the units that are most likely to retire are the ones that are the least efficient. Isn't that true?

D. SMITH: Generally speaking, yes.

MR. SHOPE: Okay. And if there are new units that are coming on to replace them, they tend to be more efficient. Isn't that true?

D. SMITH: Yes.

MR. SHOPE: Okay. So you would expect, therefore, that the more retirements you get, to the extent that there's replacement by newer units, you would expect that, therefore, prices would go down even without NECEC.

D. SMITH: You would have a longer, flatter part of the supply curve and a steeper tail to the curve, and where you are would -- in that would dictate whether you have more or less change in price per hour and how it turns out on an annual basis would depend on accumulation of that --

MR. SHOPE: And generally speaking --

D. SMITH: -- which is what we model for.

MR. SHOPE: I'm sorry, I apologize. But generally speaking, the flatter the supply curve, the less price impact effect you would get from NECEC.

D. SMITH: Yes, when it's in the flatter part, it would be less.

MR. SHOPE: Yeah, okay. Now, with regard to the retirements, you had two scenarios, low and high, right?

D. SMITH: There was contemplation early on about a low and a high, but we did not do two retirement scenarios for this work.

MR. SHOPE: You didn't choose the lower case? You didn't choose to go with a lower case?

MR. PEACO: What are you referring to?

MR. SHOPE: A lower retirement case.

MR. PEACO: No, are you referring to some -- a document?

MR. SHOPE: I'm asking you the question whether you chose to go with the lower retirement case.

D. SMITH: I'm saying there was contemplation of doing more than one scenario, and that wasn't done. One scenario was chosen. It was lower than some that you could choose and higher than others you could choose.

MR. SHOPE: Okay, but there were manual interventions in determining which plants could retire based on the economic calculations in your software, right?

D. SMITH: Yes, the operator interacts with the model when there are a number of plants that have very similar going-forward costs. When the first of those -- and this is true in reality too. When one retires, it raises the price of the next one and raises the price of the market and reduces the chance of the next one choosing to retire, and that dynamic involves -- in our model involves some amount of intervention.

MR. SHOPE: Okay. Now, in fact, with respect to Maine, was the decision about which plants could retire done iteratively in the way that you suggest or was it just done at the outset where you said, okay, here are the candidates and who might retire?

D. SMITH: All retirements in Maine and outside of Maine were on the basis of projected going-forward costs, and the feedback to pricing that occurs as the most expensive of those start to retire and no longer be in the supply stack. That includes the Maine units.

MR. SHOPE: Well, did you put together a file of delist bids that would indicate which units would be candidates for retirement and which wouldn't?

D. SMITH: Yes.

MR. SHOPE: Okay. And there were only two plants in Maine -- of all of the dozens and dozens of plants in Maine, there were only two that would have -- that your model would have even allowed to retire. Isn't that right?

D. SMITH: I don't recall the number. We -- in our model we focused on plants of reasonable size. We don't look at the really small units. So that would have limited, whether in Maine or elsewhere, the number of units we considered for potential retirement.

MR. SHOPE: All right. But because of your intervention, even if your software would have said that on economics the plant would retire, if the plant wasn't on the list as being eligible for its retirement, it doesn't retire in your model. Isn't that right?

D. SMITH: So no unit that we did not input into the model and provide the going-forward costs could retire because it wasn't included in there. Those are generally newer units with lower going-forward costs, better net energy revenues. For the units that were in and could be retired, the amount of retirement is not what was being selected. It was -- the intervention is necessary because once the first one happens, you have that feedback mechanism, and it required manual intervention to recalculate the proxy clearing price to see whether something else would retire on the basis of economics once the first unit in any given year had retired.

MR. SHOPE: Chris, I think we've actually reached a good break point. And just for efficiency, what I'd like to do is, over the break, I'd like to have the witnesses look at IECG 003-014. And there are Attachments 1 and 2, and it's a confidential exhibit.

MR. SIMPSON: Okay.

MR. SHOPE: And in particular, the question will be, while the names of the specific plants that were eligible for retirements may be confidential, I want to have an answer on my question about the number of plants that -- in Maine that you deemed -- that, by virtue of your operator intervention, you deemed to be even eligible for retirement.

MR. SIMPSON: John -- before we break, hang on a second. John, you mentioned that you might want to make a copy of another exhibit. Do you still want to do that?

MR. SHOPE: That is correct.

MR. SIMPSON: Okay, fine.

MR. SHOPE: Oh, I'm sorry. The -- we have it, but -- I'm actually updated that we have it, but I think it will be more efficient if we do it after the break.

MR. SIMPSON: Okay, that's fine. I want to be more efficient. Before we break, I want to check in with the other parties to see if their estimates have changed. NextEra, I have you at 30 minutes. Is that still your estimate?

MR. MURPHY: My estimate would be under 15 minutes.

MR. SIMPSON: Okay. IECG, I have you between 15 and 20. What is it now, Drew?

MR. LANDRY: I think no questions right now. I still may have some follow-ups.

MR. SIMPSON: Got it, okay. CLF?

MR. TURNER: I may have a couple follow-ups but nothing substantive.

MR. SIMPSON: Okay. NRCM?

MS. ELY: It's the same, maybe a couple follow-ups but nothing long.

MR. SIMPSON: Okay. Dot?

MS. KELLY: I don't have any questions currently.

MR. SIMPSON: Okay. Elizabeth, are you on the phone? Okay. All right, that's helpful. And so I think there'll be at least a couple questions from the bench. It's my understanding that there will be some redirect, and then we will go into confidential session and deal with the confidential questions. Is there anything else that I'm missing in terms of doing a cumulative time estimate?

MR. MURPHY: The only question, and it's more for myself, there are certain confidential sessions I can't be in. So can we determine -- I know all my questions are public. Can we determine whether these are going to be sessions I won't be in and --

MR. SIMPSON: Thank you. That's a good idea. John, what protective order governs?

MR. SHOPE: I think -- well, the Hydro-Quebec document is Protective Order Number 2. As it turned out, there's another version of it that's Protective Order Number 8, but there wasn't a version that was Protective Order 2. So I want to use that one because it's the lower level of protection. And the -- well, I think we're going to do -- the document that I just mentioned is confidential. It would -- is, I believe, Protective Order 2 subject to Mr. Bartlett correcting me, but I'm pretty sure it's Protective Order 2. But I don't think I need to actually get into specific -- I think we can stay in public session for that.

MR. SIMPSON: Okay. So I don't have it in front of me. Brian, do you have access to two?

MR. DES ROSIERS: Yes, he's fine.

MR. SIMPSON: Okay, great. Anything else before we break? All right, let's break and come back -- oh, sorry, Sarah.

MS. TRACY: We'll talk about it (indiscernible).

MR. SIMPSON: Okay. Let's come back at 20 minutes till, and the till would be 20 minutes to 2:00.

CONFERENCE RECESSED (January 10, 2019, 12:38 p.m.)

CONFERENCE RESUMED (January 10, 2019, 1:45 p.m.)

MR. SIMPSON: Okay, just to recap where we are and where we're going, John has some public questions. Then we're going to allow the rest of the parties to ask their public questions. We'll allow for redirect on those questions, and then we're going to go into confidential session and finish up. John?

MR. SHOPE: So we had a lunch break and -- so first off, obviously you had some time to yourselves and with your attorney over the lunch break. Any changes to your testimony that you realize need to be made?

MR. PEACO: No.

MR. SHOPE: Okay. You'll recall that I had asked you before the break about the biomass plants and whether their operation was fixed in your model as between the base and the change case. Do you remember that?

D. SMITH: Yes.

MR. SHOPE: Okay. And I'm looking at the transcript of August 2nd, 2018 when we had a technical conference, and there was a question at page 142 put by Ms. Bodell. And at line two, it reads, "Ms. Bodell: And is it true that the" -- by the way, this is lines 2 to 12 that I'm going to read. "Ms. Bodell: And is it true that the generators in Maine operate less because of the NECEC line? Mr. Peaco: Yes, I believe that's correct. Ms. Bodell: And is it true that in your model you assumed that the biomass plants do not change their operations with or without NECEC? Mr. Smith: That's correct. Ms. Bodell: That's an assumption, correct? Mr. Smith: Correct. Ms. Bodell: That's not a model output? Mr. Smith: Correct." So just to be clear, are -- is it -- are you now testifying that that testimony is not accurate?

D. SMITH: Yes, my best understanding as I sit here right now is that that was an outcome of the modeling assumptions I provided to you this morning and not an input assumption. That's my best understanding as of right now.

MR. SHOPE: Okay, so just -- so the three of you were just -- you just weren't remembering correctly back in August.

D. SMITH: Yes.

MR. SHOPE: Fair enough. We're all getting old. Now, you'll recall that I asked you about -- before the lunch break about retirements of plants in Maine. Do you recall that?

D. SMITH: Yes.

MR. SHOPE: Okay. And I had -- and I believe you had indicated that in order to be eligible for retirement within your capacity buildout and retirement system, a plant had to be placed on a list of eligible candidates. Is that right?

D. SMITH: Yes, that's correct.

MR. SHOPE: Okay, all right. So I'd like to -- if we can distribute the next exhibit. Now, I will mention that this is a confidential exhibit relating to Daymark's work. So it's Protective Order Number 2 for the exhibit, but I intend to ask questions that would not implicate the confidentiality I believe. So given the preference for public session, I'd like to proceed.

MR. DES ROSIERS: And, counsel, what number should this exhibit be?

MR. SHOPE: Thirty-three?

MR. SIMPSON: Yeah, I think it's -- the next number available's 33.

MR. SHOPE: Okay. So you have an -- first of all, this is what's been designated as Generator Intervener Exhibit 33 which is an exhibit with four pages of text. The first two pages are IECG 003-014, Attachment 1, and then the third and fourth pages are IECG 003-014, Attachment 2. Do you see those?

D. SMITH: Yes.

MR. SHOPE: And these were the two -- these were the pages that I asked you to review before the lunch break, correct?

D. SMITH: Correct.

MR. SHOPE: Okay. And were you able to review them before the lunch break?

D. SMITH: Yes.

MR. SHOPE: Okay. And so first off, is it the case that the plants that were eligible to retire in your modeling were the same in both the base case and the project case?

D. SMITH: Yes.

MR. SHOPE: Okay. So -- okay. And then the second question is is it the case that there are only two of all the plants in Maine that were considered to be eligible for retirement?

D. SMITH: Yes.

MR. SHOPE: Okay. So there were some large fossil fuel plants in Maine, such as the Rumford plant and the Casco Bay plant, that were not eligible to retire in your modeling. Is that correct?

D. SMITH: Yes.

MR. SHOPE: Okay. And also, just to be clear, so Androscoggin plant, also another fossil plant, not on the list?

D. SMITH: Correct.

MR. SHOPE: And also, my client's plant, Bucksport, not on the list, right?

D. SMITH: Yes. Would it be easier just to name the two plants?

MR. SHOPE: Well, I'm just trying to protect your confidentiality, but if you're willing to --

D. SMITH: Well, they're going to get to it by process of elimination anyway at the rate you're going.

MR. SHOPE: Okay. I mean, to be honest with you, it didn't really strike me as secret, but I didn't want to --

D. SMITH: So the Yarmouth units and the Cape turbines, gas turbines, are the units in our list.

MR. SHOPE: And by Yarmouth, you're referring to the Wyman units?

D. SMITH: Correct, the Wyman oil units.

MR. SHOPE: Okay. Thank you, that's helpful.

MR. SIMPSON: If we're lucky, the document you're looking for will be coming through the door momentarily.

MR. SHOPE: All right, we've had passed out what will be Generator Intervener 34. And these are excerpts from discovery response EXM -- so it was a response to request from the Examiners -- EXM-004-006_UPLAN -- U P L A N space -- results.xls. Now I believe you had indicated that you had reviewed Ms. Bodell's work and you had indicated that there was a change in the -- there was a reduction in the energy market price suppression benefit if one were to assume that the power that would be delivered to New England across NECEC were being diverted from other markets by Hydro-Quebec. Do you recall that?

D. SMITH: Yes.

MR. SHOPE: Okay. And I believe you had indicated that you didn't -- you hadn't studied or hadn't recalled the effect on your own assumptions if there were a switch from a constant case to -- or rather from a diversion case to an incremental case or from an incremental case to a diversion case. You remember that?

D. SMITH: I believe we indicated we hadn't done a case that included diversion so we couldn't make that comparison.

MR. SHOPE: Okay. Now, if we go to the third page of Generator Intervener 34, you'll recall that Energyzt had run a case with Daymark's assumptions, first keeping the Hydro-Quebec exports constant, and then -- so in other words, no diversion. And then they had also done a case in which there was diversion. You recall that?

D. SMITH: I believe that in the technical conferences, it was discussed that a case was run attempting to replicate some of Daymark's assumptions using the UPLAN model, and it was labeled Daymark assumptions. I don't recall what subset of our assumptions were included in those runs.

MR. SHOPE: Okay. But if you look at the changes in LMP on the far right of the page, you can see that the change in LMP in the case in which there is no diversion is a reduction of 3.2 percent. Do you see that? I'm sorry -- 3.21. You see that? For -- I'm sorry, I'm sorry. I'm trying to do too many things at once. You see the $3.21 reduction in LMP?

D. SMITH: I do.

MR. SHOPE: $3.21 per megawatt hour, you see that. And then -- and we see in the case where there's diversion directly below that, the change in LMP is only $2.60. Do you see that?

D. SMITH: I see that number.

MR. SHOPE: Yeah. So if you assume diversion rather than incremental, that drops the LMP reduction by about a fifth. Right?

MR. DES ROSIERS: I'm going to object. If -- this appears to be counsel trying to put in his own witness's analysis and have our modelers comment on Energyzt's results. If we want -- so I object. And I'm having real trouble reading it because I get -- I'm getting old and the numbers are so small, but --

MR. SHOPE: Well, my understanding of the witness's testimony before was that he had reviewed the Energyzt results and it seemed that there were savings. So I'm just following up on that, and I think that we've had similar follow-ups in scope in the CMP examinations.

MR. SIMPSON: Overruled, you can continue.

MR. SHOPE: Yeah. So you can see here that even with the Daymark assumptions, there seems to be a substantial reduction in the price suppression benefit if one assumes diversion rather than incremental. Isn't that right?

D. SMITH: I wouldn't agree to that. What this shows me is that in two runs that were done by Energyzt, the run in which there were incremental capacity and generation to serve NECEC has higher benefits than the run in which it doesn't. And I see that they have labeled it Daymark assumptions, and as I say, I don't recall what that is and it certainly isn't our run. So I would agree that this set of Energyzt runs shows a difference in benefits between those two cases.

MR. SHOPE: Okay, and you don't have any basis to disagree with the conclusion that if we were to use your assumptions and in your modeling, that switching from the incremental case that you assumed to a diversion case, which you admittedly didn't model, would reduce the price suppression benefit. Is that fair?

D. SMITH: I have no basis for making a conclusion about what switching to a so-called diversion run using our model would do, correct.

MR. SHOPE: Okay, so just as a matter of the law of supply and demand, in the incremental case, you're assuming additional supply. In the diversion case, you're assuming a constant supply just being moved to a different place. And you're telling me that you have no basis to know whether or not the scenario that increases the supply overall has a greater price suppression effect?

D. SMITH: That wasn't my understanding of the question. My understanding of the question was around the magnitude and comparing it to this. If you're asking if having less supply in a region is going to reduce prices less than having more supply in a region, then I will agree that, generally speaking, that will be correct.

MR. SHOPE: Okay, and when you say less supply, meaning you're talking about less incremental supply, right?

MR. DES ROSIERS: Objection to form.

MR. SHOPE: Let me be clear, when you say in a region, you're talking about multiple control areas that are adjacent. Is that fair?

D. SMITH: It doesn't need to be. I'm saying that if you model two cases, one that has more supply and one that has less supply, the one with more supply is going to tend to lower prices unless that supply is never sub-marginal.

MR. SHOPE: Okay. And just so -- just to be clear, when you -- your case in relation to a case that models diversion has more supply, everything else being equal.

D. SMITH: Yes.

MR. SHOPE: Okay, thanks. I think that's it for the public session for us.

MR. SIMPSON: Okay, thanks. Brian?

MR. MURPHY: Thank you and good afternoon. Like yesterday, we have a small packet for you, make it easier, I think, on both of us and to people following along. You can see the packet is not as thick as it was yesterday for the management. So -- and I'll start on the first tab. And the first tab, on the first page, you'll see that's Daymark's response to the generator interveners' 002-055 information request. In this response, you clarified that Daymark is not contending that NECEC will clear the forward capacity market but rather that it's uncertain whether NECEC will or will not clear the forward capacity market. Is that a correct reading?

D. SMITH: Yes.

MR. MURPHY: Go to tab two. And tab two, on the second page of that tab, you will find NextEra Hearing Exhibit

41 which is an information response from the Massachusetts electric distribution companies provided to NextEra as NEER 1-56 in the Massachusetts DPU case. On the first line, just so we can level set what exhibit is being referenced in that first line, it's called Exhibit JU-6. And in that proceeding, this is the TRC Qualitative Evaluation Report that was submitted as NECEC Hearing Exhibit 34. Are you generally familiar with that report and that TCR is the evaluator for the EDCs?

MR. PEACO: I have not reviewed it.

MR. MURPHY: Okay. Do you know that they are the evaluators for the EDCs?

D. SMITH: I am aware of that. I have not reviewed their report.

MR. MURPHY: And I won't be asking questions about the report, but the response refers to the report so I just wanted folks in the room and for the record to -- for everybody to understand what it was. In the first sentence it states, "It's difficult to actually forecast the capacity market price impact for individual resources." Do you see that?

D. SMITH: Yes.

MR. MURPHY: And then in the second sentence, the response from the EDCs explains that the ISO New England rules reduce the ability for state-sponsored resources to impact capacity clearing prices. Do you also see that?

D. SMITH: Yes.

MR. MURPHY: Is it fair to say that the Mass. EDCs are setting forth a general proposition that it is unclear whether any of the resources bid into 83D, including NECEC, would clear the forward capacity market and impact clearing prices?

MR. PEACO: I'm not sure if I follow your conclusion from this statement. Can you help me?

MR. MURPHY: Definitely. I read this statement as not focused on your particular project but all the projects that were bid into 83D and that there is a general uncertainty whether any of them would clear the forward capacity market. And take your time, especially I -- this could be the first time you've read this response.

MR. PEACO: Well, I guess it only refers to reducing the ability. It doesn't -- I don't read this as going as far as your statement, and so I just want to make sure I understood your statement and whether I'm understanding it correctly or not.

MR. MURPHY: So what I am saying is the first premise here was that they're saying it's difficult to forecast whether someone's going to clear the forward capacity market. That's their first statement. The second one is they allude to the ISO New England rules, reducing the likelihood that a state-sponsored resource will be able to clear the forward capacity market and impact capacity prices. So I wanted to make it clear for the record that it's a fair statement they are not talking about just your project but all the projects that were bid into 83D. And if you don't feel comfortable confirming that, that's -- but I think --

MR. PEACO: Beyond what the paper says, I'm not sure -- I mean, I'm not familiar with the response or the report. So, I mean, I can just tell you what I read from reading the page here is that what you said was different than what I was reading here.

MR. MURPHY: We're definitely talking past each other which is not my intent.

MR. PEACO: No, that's why I'm trying to clarify what you're asking.

MR. MURPHY: So again, what I'm asking is the way I read this is it's not focused solely on your project. Is that a correct statement? You don't see them narrowly focused on your project.

MR. PEACO: It's generally referring to state-sponsored resources if that's what -- I agree with that.

MR. MURPHY: Go back to the first page. And this is also a response from the EDCs to NextEra or NEER's information request 1-48 in the Massachusetts 83D proceeding. And in that response, under little A you'll see that it explains that TRC's report did not include capacity benefits in their final evaluation of any project which would include the NECEC project. Am I reading that correctly?

MR. PEACO: That's how I would understand it, yes.

MR. MURPHY: Go to tab three. And let's turn -- this is an excerpt from NextEra Hearing Exhibit Number 6, and these are two pages from the HQUS bid with the Vermont clean line into the Connecticut zero carbon energy RFP. And I'd like to go to the second page and under Section 4.1 to the sentence that starts with "As of today." And do you see that sentence?

MR. PEACO: I do.

MR. MURPHY: In this sentence, the bidder, which is HQUS, is stating that the HQ hydro resources do not qualify as renewable technology resources under the ISO New England rules. Am I reading that correctly?

MR. PEACO: Yes.

MR. MURPHY: And then HQUS goes on to conclude that potential capacity offers from this bid replace price mitigation creating uncertainty about whether the offers would have the ability to clear the forward capacity right auctions. Is that correct?

MR. PEACO: Yes, I see that.

MR. MURPHY: This statement of HQUS, the way I read it, is congruent with your general conclusion that there's uncertainty whether NEC (sic) will clear the forward capacity market. Is that also correct?

MR. PEACO: That's correct.

MR. MURPHY: Now we'll go to tab five. And this is a different response from Daymark to generator interveners' information request 002-019 in this proceeding. In the first sentence of your response you state that if the same quantity of energy in the same hours as NECEC was injected into Massachusetts via another transmission line, the energy price suppression impacts for ratepayers in Maine for the hypothetical line would be similar to the price suppression impact for NEC (sic). Do you agree that I'm reading that correctly?

MR. PEACO: I may have missed -- where were you reading?

MR. MURPHY: From the very first sentence. And take your time. I know there was a lot of data responses in this proceeding.

MR. PEACO: So you're asking just about the first sentence? Because I didn't -- I may not have followed along, but I didn't hear it exactly the way it was on the page so -- but --

MR. MURPHY: I think the general proposition and this is what I want to get to make sure that we're understanding the general premises and maybe it'll help just to go there. My understanding of your response is because of your assumption that there is a general relative lack of congestion in ISO New England, if a different line was interjected into

Massachusetts, that the energy price suppression benefits would be similar to those that you would see with NEC (sic) for Maine ratepayers.

MR. PEACO: That's correct. That's a fair reading.

MR. MURPHY: So for purposes of my next question, if one accepts your premise that there is a lack of congestion in ISO New England, then does it follow that if the NECEC line ultimately does not get approved, does not go forward, but instead another 83D project gets built that interjects the same quantity of energy in the same hours as NEC (sic), then Maine ratepayers would experience a similar level of energy price suppression and it doesn't -- this -- the -- you can see what I'm saying is it doesn't have to be Massachusetts. It could be anywhere on the system, given that your general premise is there's a lack of congestion.

MR. PEACO: Maine would see a benefit from that. It would just not be to the same degree.

MR. MURPHY: It would be similar? That's what I'm reading your data responses --

MR. PEACO: It's similar, but it would be less pronounced than in our NECEC analysis.

MR. MURPHY: Thank you. Those are all my questions.

MR. SIMPSON: Thank you. Any questions from IECG, Drew?

MR. LANDRY: I do have a couple of questions and follow up I think primarily to the generator interveners' questions which I wondered if, in your modeling, you had made any assumptions about the addition of additional hydro resources, generating resources by HQ, during the period of the forecast.

D. SMITH: We did add additional capacity to meet future load growth in Hydro-Quebec such that their ability to export stayed relatively similar throughout the study period.

MR. LANDRY: But you made -- so your assumption -- you made no assumption that they might build generation in advance of future needs?

D. SMITH: Beyond -- no, not into the study period. That's correct.

MR. LANDRY: If you had assumed that they had constructed generation in excess of what they needed for internal purposes, would that have changed the outcome of your results?

D. SMITH: There would be -- if -- in that case, there would be more energy to sell. And to the extent that there was markets where it was profitable to sell, where more energy could flow economically, you'd see more energy flow and you'd see lower prices resulting from the additional energy in the system.

MR. LANDRY: Thank you very much.

MR. SIMPSON: Sue, any questions?

MS. ELY: No questions.

MR. SIMPSON: Phelps?

MR. TURNER: No questions.

MR. SIMPSON: Dot?

MS. KELLY: No questions.

MR. SIMPSON: Elizabeth, are you on the phone? Okay. Do any of the other parties have any questions? Public questions. All right, let's go to bench questions. Mark, I know you have some.

MR. VANNOY: Thanks. So my questions are more of a general nature and more of a -- kind of the trajectory that ISO New England has been on in the regional markets. So as I'm thinking about that with respect to this case, would it be fair to say, in the past, capacity has generally been based on reliability -- or reliability -- how much capacity is bought is based on reliability modeling looking forward?

MR. PEACO: That's correct, it's been a resource adequately-based assessment historically.

MR. VANNOY: And in the fuel security discussion with the operational fuel security analysis that the independent system operator in New England did and then FERC seemed to adopt in their last order as an appropriate model, what -- there is an -- or the baseline of that model included imports. And those imports, did they include the Massachusetts purchase here? Are you familiar with that?

MR. PEACO: Yes, I am, yeah.

MR. VANNOY: So how would you characterize the imports in that model?

MR. PEACO: My understanding of the import modeling that they did initially and they modified it slightly in the last filing, but they did three levels of imports. There was 2,500 megawatts, 3,000 megawatts, and 3,500 megawatts. And the -- in my review of the materials there, the -- my understanding is that the 2,500-megawatt level was based upon ISO New England's historical experience with imports with a fairly high capacity factor. The 3,000 represented what they viewed as sort of the high end of the existing capabilities. And the 3,500 case is a scenario they represented that would be achievable only with additional transmission into the region. And to my understanding in reading the case is the -- when they started that analysis, they were considering the 83D proposition generally, but obviously now that's specific to this project. So to my understanding, the 3,500 level that they've been modeling would require NECEC or something equivalent to that to get to that level in the way they've done the analysis.

MR. VANNOY: Somewhere in the region. As you followed the fuel securities discussion, would it be fair to say that the fuel securities discussion seems to bifurcate what we traditionally thought of as a capacity supply obligation from fuel security? In other words, I think -- as I think about it, it seems to me in the past, capacity supply obligation seemed to imply that you had a fuel requirement. In the discussion right now, it almost seems like it doesn't totally imply a fuel requirement because we're going to create incentives to ensure that that fuel's there in the future.

MR. PEACO: Yeah, and I think what they found is that the requirements they had prior to this discussion didn't adequately provide for the fuel security behind the capacity that was being bid into the market. So that's led them to needing to address that in some way.

MR. VANNOY: So then we had winter reliability program. We had pay for performance. We're kind of laying out some history here. And in pay for performance, we started to reward any energy suppliers really in the real-time energy side regardless of whether they had a capacity supply obligation for supplying during that scarcity event, whatever the trigger was.

MR. PEACO: Correct.

MR. VANNOY: Is that accurate?

MR. PEACO: Yes, it is.

MR. VANNOY: So the market redesign that's going on right now is looking at energy markets. Is that correct?

MR. PEACO: Energy and ancillary services, yes.

MR. VANNOY: As primarily the solution going forward in the future.

MR. PEACO: Beyond this interim solution for the next couple of auctions, correct.

MR. VANNOY: So the economics incentives to perform during scarcity are likely going to be in the energy market and not in the capacity market?

MR. PEACO: That's ISO's proposal now. Obviously they're still in the midst of negotiating that with the stakeholders, but their proposal would have basically a week ahead or a multi-day ahead component to the energy markets. And then they'd also have the storage or basically an ancillary service market that incented people to have a certain amount of energy storage available to them. And so those are -- those would be more on the energy market side of things than in the capacity market per se.

MR. VANNOY: So when you look at a future where the economic incentives to perform are going to be really in the energy market and less so in the capacity market, in a future where -- acknowledge that we've tried to get new natural gas infrastructure into the region and have not been terribly successful. So with those kind of incentives set up, how would you advise the Commission to look at these kind of transmission or energy infrastructure type projects? What's that future look like?

MR. PEACO: Yeah, where ISO is heading with the market change, they're clearly setting up market mechanisms.

The energy market -- redesigning the energy markets and the ancillary service markets to provide additional revenues to fuel secure resources. And as I understand the NECEC, they would clearly qualify as one of the most fuel secure resources like the other imports that ISO has been modeling in their analysis. So what that -- it will give an extra revenue stream to those resources that can provide fuel security. It will add some cost, and I think to the extent that NECEC or imports of that type do come into the market, they clearly would help mitigate -- they would increase the supply of secure -- fuel secure resources. And presumably that would -- in a market construct, would help mitigate the increased prices that would otherwise result from adding these components to the energy and ancillary service markets. The corollary would be because you're supplying fuel secure resources more revenues, they would have -- when they're bidding into the capacity market, they would have somewhat more energy and ancillary service revenues to offset what they would need to bid to get compensation from the capacity market. So they would have somewhat less need to get revenues out of the capacity market so that might change the bidding dynamic in the capacity market with the fuel secure resources having more opportunity for revenue in the energy markets.

MR. VANNOY: So that would drive towards actual performance -- or payment for actual performance rather than payment for having (indiscernible) on the ground.

MR. PEACO: That's correct.

MR. VANNOY: So even if -- let's take a step back. Say the fuel security program that ISO puts in place doesn't allow -- or won't -- let's say there's a concern on ISO's part about not seeing the actual units or not dispatching the actual -- however you want to say that. But -- so it's geared more to fuel security of resources in the region. Even in the pay for performance, PFP -- even in the PFP construct, isn't that going to drive an economic -- or that's going to drive an -- let me rephrase that. In the PFP construct, what's the total megawatt hour payment allowable once it's fully implemented?

D. SMITH: Currently the high end is $5,455 a megawatt hour starting in FCA 15.

MR. VANNOY: So if you were simply an energy supplier, had no capacity supply obligation, and you performed during a scarcity hour, you would potentially earn that number for that hour?

MR. PEACO: Correct.

MR. VANNOY: So that seems to me like a pretty significant incentive to deliver during those scarcity events.

MR. PEACO: That's the intent, sure.

MR. VANNOY: Okay, thank you.

MR. SIMPSON: Bruce, any questions? Faith? Chris?

MS. COOK: I just had a follow-up question too where

I think Mr. Shope began this morning, and as I understand it, in the pre-bid phase when Daymark started their work, they identified a MOPR calculation as something that would be appropriate to do and had actually requested information from HQ that would allow you to do a MOPR calculation. Is that right?

D. SMITH: Yes.

MS. COOK: So what happened? Why didn't you do a MOPR calculation?

D. SMITH: We didn't receive information from HQ. They considered it highly confidential and didn't provide that to us or, to my knowledge, to anyone on the project team. And so we chose to take a different approach and simply qualitatively discuss the uncertainty and reflect a value that could possibly be achieved depending on the results of the actual MOPR calculation when it occurs and the subsequent auctions.

MS. COOK: And that different analytical approach, did you discuss that with the CMP people?

D. SMITH: I'm sure we had -- I don't recall a specific conversation detailing it exactly the way I did here, but we had many conversations about our analytical choices. I'm sure we did.

MR. PEACO: The other thing to say, and I think this has been mentioned before, but when we were initially setting up the analysis, obviously the bid to the Massachusetts EDCs -- EDUs was -- did not explicitly include capacity as an offering. It was sort of another benefit in their evaluation metric so it was less critical when it -- so when it became apparent that we wouldn't have -- for that purpose, our analysis would simply be to add some color to the primary bid they had. It wasn't really central to the offering. They weren't offering capacity per se, but it would -- it clearly was one of the things that they would consider as another benefit. So it had less overall importance in the bid preparation to the energy analysis, and when we became -- when we realized we really weren't going to be able to put together a meaningful calculation for that, we just -- we decided on the bounding exercise as a useful way to proceed with it.

MS. COOK: And did you reevaluate that assessment when you were considering what you were going to file in connection with the CPCN petition here?

MR. PEACO: I don't remember a specific conversation on that, but we didn't really have -- I think at that point it became apparent that we really weren't going to have the kind of information on the project that would be necessary for us to do anything other than our best case as to what it might look like. And so I think the decision was made that we'd stick with the approach that we used in the July report.

MS. COOK: Thank you.

MR. SIMPSON: All right, any questions before we go to redirect?

MR. SHOPE: I don't want to go out of turn, but Commissioner Vannoy had asked a question about whether or not a pay for performance bonus would be available to a generator that did not have a capacity supply obligation, and I believe Mr. Peaco had answered yes. And I just wanted to confirm that that is, in fact, his understanding, that a generator without a capacity supply obligation would have the ability to receive a pay for performance bonus for showing up and providing energy.

MR. PEACO: Yes, that is my understanding. Doug, do you have anything to add to that?

D. SMITH: Yes, it is my understanding as well.

MR. SHOPE: Okay. That's it. The rules will speak for themselves.

MR. SIMPSON: Dot?

MS. KELLY: Hello, gentlemen. On that same line, I was curious if you had an opinion on whether efficiency measures would also -- if they were in force during those times of shortages, would be available to get the same payment?

D. SMITH: I'm sorry, which payment are you referring to?

MS. KELLY: So this would be either efficiency measures that would be like lighting that had changed and so, therefore, is reducing the amount of energy that is required and, therefore, during a time of shortage, it's actually still in play, whether that is excluded, not addressed, or included. I know these are just developing.

D. SMITH: I'm not aware of anything specific. I know that demand resources are being discussed. I don't know where they're landing or even where they've landed so far. It's not been a focus of our review. But certainly, especially active demand resources, not so much passive, are certainly something that's frequently discussed in market rule changes such as these.

MS. KELLY: So just as a follow up, if it was an active resource like a solar resource that could show it was operating during a time of shortage, would you say that they would be available to take advantage of this pay?

D. SMITH: Generally, demand resources are divided into those that are just sort of passively reducing. So they're behind the meter and they're just passively reducing the load that is being served by the bulk power system and -- versus something where a company might actively turn on local generation in order to avoid drawing on the bulk power system which would be a more active demand response. So that's the distinction that I was drawing.

MS. KELLY: I seem to have conflated a few things so thank you.

MR. SIMPSON: Jared, redirect?

MR. DES ROSIERS: Thank you. Panel, there were some questions from Mr. Shope with respect to the potential that HQ, over the NECEC, would not deliver or make some business choices not to deliver during a cold snap, for example, when demand was high in Quebec. And I guess my first question related to that topic is in that situation where we're in -- having a cold snap or a polar vortex or whatever we'll call the next event, what would be the incentives for HQ with respect to its performance for delivering -- selling power into New England?

MR. PEACO: Well, they clearly would have strong incentive to deliver during those hours because of the price, and I think as you quoted yesterday, the prices that were evident during those periods, particularly the cold snap last winter, were substantially higher than anything you'd see normally. And so they would have very strong incentive to be available and selling during those hours.

MR. DES ROSIERS: Now there was also the question about serving Quebec load which presumably, it's cold here, it's cold there, and you mentioned some contractual arrangements between HQ Production versus HQ Distribution. Can you explain what you were referring to?

MR. PEACO: Sure. Hydro-Quebec for, I don't know, a number of years now has basically operated as a functionally unbundled or functionally separated entity. They have a production group that's functionally separate from their distribution and their transmission. The -- when the functional separation occurred, there was a supply agreement for a fixed amount of energy, fixed shape, fixed price between production and distribution. And then over -- any loads over and above that amount, distribution is responsible for doing supply planning and procurements to get supplies sufficient to meet their overall demand. Production does not have obligations to that other than any obligations they might willingly take on in a procurement. So the extent that distribution finds themselves in a situation, a cold snap, they could -- they have plans to cover those, but it doesn't fall as an obligation to production to provide that other than -- any more than it would any other market entity. And that would -- it would not be in an obligation to sort of breach other contractual commitments they would have made such as the one through NECEC.

MR. DES ROSIERS: There has also been a suggestion that, you know, as an example, during the 2017/2018 cold snap, exports from Quebec were reduced, particularly over the Phase II intertie. And do you understand why there were reduced flows on that line during the cold snap?

MR. PEACO: Yes.

MR. SHOPE: Objection, scope.

MR. DES ROSIERS: The suggestion here was, in questioning with respect to HQ's behavior during a cold snap, that they would have an incentive not to sell into New England. I think it's fair and appropriate to both explore the historical facts with respect to that scenario.

MR. SHOPE: That has nothing to do with this question. The prior question related to incentives.

MR. SIMPSON: Objection's overruled. Go ahead and answer the question.

MR. PEACO: Yes, well, there's two pieces of information that are important here. One is -- and this is -- there's a report to the -- that ISO New England made to the participants committee right after the cold snap and indicated that there was an event that derated the Phase II line by 50 percent of its capacity. So it was derated down to a thousand megawatts which would limit flows on the line, and that extended for most of the cold snap. But the independent market monitor's report sort of -- for the winter, last winter, shows that, subject to that cap, that the flows on the Phase II line were at 1,000 throughout the cold snap period. So Hydro-Quebec, at least on that line, did perform to the maximum allowed by transmission at that point.

MR. DES ROSIERS: Now as -- now we began the testimony this morning with respect to some questions with respect to the gas forecasts, and there were a number of gas forecasts put before you. I guess -- and the questioning from counsel focused on the relationship of the gas forecasts to the

Henry hub and the -- in particular the AEO forecast for Henry hub. What is the relevance of the Henry hub pricing to the pricing of gas in New England?

MR. PEACO: Henry hub is one of the more liquid pricing points and it's used as a reference point in New England. The Marcellus area is also a place for price formation, is forming as a hub as well, but Henry hub is considered -- there can be price separation. But the relationship to New England is only related to the underlying commodity component of the cost of delivered gas in New England. It wouldn't account for any congestion or limitations of delivery to New England. So the underlying commodity, obviously it needs to be purchased for any deliveries, but the delivery costs can be very different when you're looking at delivered price of gas to generators in New England.

MR. DES ROSIERS: And with respect to a gas forecast -- and you had to use a gas forecast in your modeling. But even in times of low gas prices, is the price of gas always consistently low? And what does it -- what does volatility do in your analysis? Or how is volatility assessed in your analysis?

MR. SHOPE: Objection, scope. There were no questions about volatility.

MR. DES ROSIERS: The suggestion is the benefits would be -- or the gas prices would be low or lower and, therefore, reducing the benefits. I think exploring instances and episodes such as the cold snap when gas prices are higher is a fair -- within the scope of questioning as to gas price and the modeling.

MR. SIMPSON: Overruled.

MR. PEACO: Yeah, and the gas -- and obviously, as we've seen, the current commodity gas prices are very low in -- say, at Henry hub, but in the cold snap last winter as an example, the gas prices delivered to New England clearly went, average, I think well over $10 a million BTU and it went much higher than that in some hours. And so -- and that -- even though the commodity price isn't there, the congestion in New England during those periods produced a very high result during -- you know, very much -- it illustrates the volatility of the price even when the commodity price itself is at a fairly low level.

MR. DES ROSIERS: And what is your takeaway from all of the different gas forecasts that have been presented in the case and all of the suggestion that you had the highest and there could be lower gas prices? What's -- what do you take that -- what should the Commission take away from that for purposes of assessing the NECEC?

MR. PEACO: Well, it -- to the answer that I gave to Commissioner Vannoy earlier, I think that clearly gas prices are uncertain and they're volatile. And in -- and even looking at sort of average commodity prices over time, there's quite a range of possible outcomes. And if you talk to any individual who's doing gas forecasting, if you ask them for forecasts for 2023 to 2040, you'll get quite a wide range of possible outcomes. So the uncertainty is there, and obviously the value of a resource like NECEC is there when gas prices are low but is clearly very much enhanced during times of high prices due to either volatility or changes in fundamentals that take the long -- take the gas prices higher than some of the lower-bound estimates, where they might go.

MR. DES ROSIERS: You also were provided Exhibit Generator Interveners 34 which appears to be model results from the Energyzt model with various cases, with various outputs. My apologies for having to read the small print, but as I understand it, in -- and correct me if I'm wrong. In all of the cases reflected here, is there a price suppression benefit that's positive?

D. SMITH: Yes.

MR. DES ROSIERS: And does it range from $2.30 to $3.21?

D. SMITH: It does.

MR. DES ROSIERS: And -- now, there was also discussion about the capacity market and uncertainty in the capacity market and uncertainty as to whether the NECEC will clear. And why -- if it's Daymark's view that it's uncertain that NECEC will clear, why did you present an analysis modeling the potential price suppression benefit for NECEC in the capacity market?

MR. PEACO: We had -- it was our understanding in the communication with Hydro-Quebec that they intended to bid capacity into the market and they obviously had a -- they -- although we didn't have information from them on -- qualitative information, we clearly had an expression that they had intended to bid a substantial portion, if not all of this, of the eligible capacity into the capacity market as a result of this. And they have every incentive to do so because they're offering a resource that's essentially base loaded and could qualify. And if they're selling the energy anyway, they have every incentive to try to monetize the capacity value to the extent that they can.

MR. DES ROSIERS: And is there any circumstance that if HQ is able to qualify some amount of capacity from one megawatt to 1,090 megawatts, that it would cause harm to Maine consumers?

D. SMITH: No.

MR. DES ROSIERS: And if NECEC does not ultimately clear any capacity in the primary auction, are electric consumers in Maine or New England in any way harmed?

D. SMITH: No.

MR. DES ROSIERS: We talked about -- there was some questioning about your retirement model and about operator intervention. And I just -- if you could very simply explain what it is you modeled with retirements and what were you trying to do with that model for purposes of analyzing the NECEC.

D. SMITH: Certainly. So the forward capacity auction is a descending-clock auction in which units can choose to bid to exit the auction and other units obviously bid to enter the auction. That's an iterative process in reality. As each event -- as the price declines and an event occurs, somebody comes in or out of the market, that changes the amount of supply and it changes the dynamics of the auction. Our model captures that iterative algorithm. It requires, however, a manual step to move from one iteration to the next, and that's what's meant by manual intervention. That's probably about as simple as I can put it.

MR. DES ROSIERS: Now you were provided Exhibit Generator Interveners 33 which was the list of units that you -- is this the list of units that you analyzed for purposes of retirement in your model?

D. SMITH: Yes.

MR. DES ROSIERS: And why did you only include two from Maine?

D. SMITH: The -- we made choices based on a number of criteria -- age, the type of fuel, the size of the units.

And we also checked that against ISO's published at-risk unit list. The concept was really twofold. One, we were looking to analyze the impacts that the NECEC might have on retirements so that the NECEC, as has been discussed frequently in this proceeding, is going to have impacts primarily on units' operating results, what price they can get or how often they would run. Those are covered in the going-forward cost component of a unit's delist. That's where the impact to the NECEC would be. So that's what we focused on in this analysis. So the units that were included and the units that were excluded were on that basis, not any attempt to focus on any region or any state.

MR. DES ROSIERS: Why wouldn't you, if you could run a model with all the units in New England -- or all the units in Maine for doing an analysis for retirement?

D. SMITH: Well, from a practical standpoint, it simply slows down modeling and increases effort and takes longer to create results. Additionally, these units are exiting in order based on their economics and based on the -- their bids. So if you add in additional units that are less likely to bid high enough to go out before all the units that we do include, it doesn't change the results. It just adds additional units into the mix. So in our professional judgment, we had more than enough units to cover the range of potentially economic outcomes of a 20-year auction.

MR. DES ROSIERS: Now you said you focused on the going-forward cost aspect of the retirement decision. Does that mean that -- what didn't you then include as part of this modeling?

D. SMITH: The primary component that we did not include was -- is pay for performance. That's, in our experience, a very large consideration for units. But it's also a risk consideration, and they have to -- a generator has to make decisions around how many events they think they -- will occur, how well they will perform, what's the risk of non-performance, and what's the balance of likely outcomes for them in terms of payments or revenues from that program. It's our belief that that is not materially impacted by the NECEC so it was not part of the consideration of whether NECEC would cause a retirement. But there are certainly units that may be far more likely to retire based on their interpretation of their risk of pay for performance. It simply wouldn't be due to the NECEC.

MR. DES ROSIERS: Now, in your modeling using the approach that you did focusing on going-forward costs, did it identify any units in Maine that would retire for those reasons?

D. SMITH: No.

MR. DES ROSIERS: And the modeling of the units outside of Maine that retired, there were some outside of Maine that were deemed -- would have -- at risk -- would have retired?

D. SMITH: That's what our model showed, yes.

MR. DES ROSIERS: And did you then think through whether those units that retired elsewhere would be -- you know, if the unit in Connecticut retires with these parameters, what would that tell us about other units in Maine such as the ones that Mr. Shope asked about, Androscoggin Energy, Rumford Power, Bucksport Generation, Maine Independent Station?

D. SMITH: Certainly. In general terms, as I said, when focused on going-forward costs, there is a lot of information about what various units across the region have for going-forward costs, and, in general terms, the newer the unit, the more efficient the unit, the lower its going-forward costs are likely to be. And that was borne out by the units that were selected for retirement through the algorithm. They were -- tended to be older, less-efficient units.

MR. DES ROSIERS: Now, you mentioned that for other reasons, such as pay for performance, that there may be units in Maine that would be more likely to retire.

D. SMITH: Correct.

MR. DES ROSIERS: Do you have an assessment based on the information you've received in this case and the analysis you've done in this case which units would be more likely to retire?

MR. SHOPE: Objection, scope. There were no questions on this subject.

MR. DES ROSIERS: The argument in the case and in the question were with respect to retirement of Maine units and whether -- why they were included or not included in the analysis and whether they are going to retire with the suggestion from the questioning that these units were omitted because they are apt to retire. So I believe the inquiry is relevant to the issue of retirements for Maine units.

MR. SIMPSON: John, go ahead.

MR. SHOPE: If I may speak, I don't think it's appropriate to try to suggest that there's some sort of -- you know, that -- so inferences from the question are somehow relevant. The question is what was the question, what was the answer, is it within the scope. And there was absolutely no question that asked which Maine plants do you think are likely to retire. The question was which plants were on your list of those that could even be considered by your model. They gave that answer. They've allowed on redirect to explain why they picked those plants. I think we've covered the subject.

MR. SIMPSON: Jared, any response?

MR. DES ROSIERS: Well, I would reiterate that the questioning is intended to suggest that Maine units at risk of retirement were omitted from the Daymark analysis in such a way that it impacted the results to present a better picture for

CMP. And we are wanting to explore that, and I can explore it specifically to the units that have been identified at risk which are the biomass units and the units listed in -- a Wyman unit and the others that Mr. Shope listed and identified specifically.

MR. SIMPSON: I'll allow it. Go ahead and answer.

D. SMITH: So in the course of this docket, we've had opportunity to review a number of confidential documents and information combined with what we know about -- publicly about where risks are going over time as the -- as costs increase would be suggestive that there are units at risk for reasons other than the NECEC.

MR. DES ROSIERS: The -- there was also a lot of questions about diversion. I don't usually say that word and I didn't put it in air quotes, but do you believe that Hydro-Quebec, when the NECEC goes into operation, will divert power from other regions in order to flow power over the NECEC?

MR. SHOPE: Again, objection, scope. The questions were simply what the person had modeled.

MR. SIMPSON: Overruled.

MR. PEACO: No, we think there's representations that Hydro-Quebec have made to us and the CMP team, and the evidence that we've seen more recently in some of their spilling energy and so forth, there's no basis to believe that there's -- they're going to be curtailing deliveries to other markets to provide this -- the power over the NECEC. They clearly have surplus energy that they're looking for a market for, and they won't need additional transmission over what exists today to deliver that to a market. And New England being the most attractive of those.

MR. DES ROSIERS: And your model that assumed that Hydro-Quebec would increase the -- their exports to flow power over NECEC, in your view, does that remain a reasonable assumption for purposes of analyzing the impacts of the NECEC?

MR. PEACO: Yes.

MR. SHOPE: I'm sorry, I'm going to object to the question. That question did not make any sense to me. Or at least can we have it re-read?

MR. SIMPSON: Okay, could you please repeat the question, Jared?

MR. DES ROSIERS: Counsel for the generator interveners asked a number of questions with respect to your assumption for your modeling that the -- HQ would increase the overall flows or that flows would increase in the world -- in the case with NECEC. You remember that questioning?

MR. PEACO: Yeah, I do.

MR. DES ROSIERS: And he asked a number of questions wanting to ask whether you modeled a case where you fixed the exports, held them constant, but just increased the amount going to New England. Do you remember those questions?

MR. PEACO: I do.

MR. DES ROSIERS: And you indicated you didn't run a case with the constant exports.

MR. PEACO: Correct.

MR. DES ROSIERS: And your only case you ran increased the flows.

MR. PEACO: Correct.

MR. DES ROSIERS: Sitting here today with everything you know and have seen in this case, do you believe that your assumption that there's -- can be an increase in flows over the NECEC is a reasonable assumption for modeling the impacts of the NECEC on the New England and regional energy markets?

MR. PEACO: Yes.

MR. DES ROSIERS: That's all I have, thank you.

MR. SIMPSON: Is there any recross? Yeah, Brian?

MR. MURPHY: I believe this was on the first round of questioning and the division between Hydro-Quebec Production and Distribution. One, I want to clarify, make sure I understand, and two, I have some questions about it. What I thought I heard was that you had read a contract between Hydro-Quebec Production and Distribution. Did I hear that correctly?

MR. PEACO: I didn't say that I read it. I said that it existed.

MR. MURPHY: Okay. So you don't know whether -- because in my experience, a lot of those contracts actually have provisions for emergency call in certain circumstances. So you wouldn't know whether it has that.

MR. PEACO: I've just -- I've read the representations that HQD has on their website in terms of what it is. I understand that there may be a provider of last resort provision there, but there's a fixed -- they basically stated directly they have a fixed amount of energy at a fixed price with a fixed shape that's under contract, and the rest is procured through their procurement in accordance with their supply plans.

MR. MURPHY: And their procurement, as I understand it, also has an open tender process where production can, over and above the base that they are required to provide, can also compete in that. Is that --

MR. PEACO: I believe that's correct, yes.

MR. SIMPSON: Hold on just a sec. We're entering that part of the afternoon where people are getting tired. Please wait until one person's done speaking before you respond.

MR. MURPHY: And I appreciate those rules, and I apologize. I will -- I'm done.

MR. SIMPSON: Okay. I didn't mean to cut you off.

MR. MURPHY: No, no. If I had another question, I'd ask it. I don't.

MR. SIMPSON: Okay, good. Any other questions for this panel that are public in nature?

MR. SHOPE: Yes.

MR. SIMPSON: Go ahead, John.

MR. SHOPE: We distributed earlier Generator Intervener 33. Did the panel get that? Okay, can we give that to the panel?

MS. TRACY: Is that 29?

MR. BARTLETT: This is 29.

MR. SHOPE: Oh, I'm sorry, 29 with the backup.

MR. BARTLETT: Yeah, the backup.

MR. SHOPE: Oh, I apologize. It got mislabeled.

MR. WILLIAMSON: While we're looking at 29, just a quick question. There was a question yesterday asked to a clear indication of source on -- this is 29, right?

MR. SHOPE: Yes, yes. And this is the ISO New England data. Okay. So you recall that Mr. des Rosiers asked you some questions about a cold snap that occurred at the end of 2000 -- of December of 2017 going onto the first days of -- first several days of 2018.

MR. PEACO: Yes.

MR. SHOPE: Okay. And you're aware that during that cold snap, deliveries from Hydro-Quebec into New England declined significantly. Are you aware of that?

MR. PEACO: As I mentioned in my response to Mr. des Rosiers, I'm aware that the -- there was a transmission issue that derated the Phase II line to a thousand megawatts.

MR. SHOPE: Okay. And is it your believe that that was the cause of the reduction in deliveries from Hydro-Quebec to New England during that cold snap in the end of December of --

MR. PEACO: That's my understanding upon reading the ISO New England materials regarding that event.

MR. SHOPE: Okay. I'd like you to -- I'd like to draw your attention to the third page of Generator Intervener 29, and this is the ISO New England morning report. And you can see in the upper left the source of the information. And you go down to see Phase II and where it says, "For purchase and sales." So you see item E under "Megawatts, Capacity, Deliveries, Net Purchases, Net Sales."

MR. PEACO: I'm with you there.

MR. SHOPE: What's that? Do you see that, sir?

MR. PEACO: I do.

MR. SHOPE: Okay. And then you go down, and do you see Phase II?

MR. PEACO: I do.

MR. SHOPE: Okay. And then if you go over to the right, do you see on December 27, 700 megawatts.

MR. PEACO: Minus 700.

MR. SHOPE: Yeah, minus seven. And then do you see so on the 28th that there's the minus 1,000? That would be the

1,000 rating that you were talking about, right?

MR. PEACO: I presume so, yes.

MR. SHOPE: And then to the right of that it says 994. Do you see that?

MR. PEACO: I do.

MR. SHOPE: And then to the right of that it says 762.

MR. PEACO: I see that.

MR. SHOPE: Negative 762. So negative 994, negative 762, negative 763, negative 992.

MR. PEACO: I see that.

MR. SHOPE: And then again -- so January 2nd it's negative a thousand so that's a day when it's at the new rating, right? Is that right, sir?

MR. PEACO: Yes.

MR. SHOPE: And then to the right of that it's -- on January 3rd it's negative 700 so 300 below the rating on that day. You see that?

MR. PEACO: I see that.

MR. SHOPE: Okay. And then if we flip the page, again going along Phase II for January 5th, do you see negative 598?

MR. PEACO: I see that.

MR. SHOPE: And then on January 6th negative 598.

MR. PEACO: Yes.

MR. SHOPE: And then on January 7th, negative 798. Do you see that?

MR. PEACO: Yes.

MR. SHOPE: So that was one, two, three, four, five, six, seven, eight -- on nine of those days during that cold snap that we talked about from December 29, 2017 to January 12, the deliveries across Phase II were less, and in some cases substantially less, than the 1,000 rating.

MR. PEACO: That's what this says, yes.

MR. SHOPE: Yeah, okay. So that would suggest that the cause of reduction in deliveries, at least on those days, was other than the change in the rating.

MR. PEACO: It doesn't to me.

MR. SHOPE: It doesn't to you?

MR. PEACO: No.

MR. SHOPE: Why -- so --

MR. PEACO: Because it's inconsistent with what the independent market monitor's reported for performance on Phase II over that period.

MR. SHOPE: Okay. So you're saying that the ISO data is inconsistent with what the independent market --

MR. PEACO: I'm saying I haven't seen this data, but I've read the independent market monitor's report, and they've indicated that Phase II performed at a thousand megawatts throughout the period.

MR. SHOPE: Well, what you had mentioned earlier was that the independent market monitor reported that there was a derate. The independent market monitor did not give an analysis of why it was that Hydro-Quebec pulled back.

MR. PEACO: No, I obtained a derate -- I believe I mentioned this in my remarks earlier. There was a report to the participants committee by the chief operating officer of ISO New England that indicated the derate of the Phase II line.

MR. SHOPE: Okay, if we look down on that same page that we started on, which is the third page of Generator Intervener 29. So it says "Import limit megawatt." Do you see that? And then do you see Phase II?

MR. PEACO: Yes.

MR. SHOPE: Okay. And do you see where it repeatedly lists minus a thousand?

MR. PEACO: Yes.

MR. SHOPE: Okay. So that's reporting the derate, right?

MR. PEACO: Yes.

MR. SHOPE: So that's consistent with that the independent market monitor reported --

MR. PEACO: It's consistent with --

MR. SHOPE: -- derate --

MR. PEACO: No, that's --

MR. SHOPE: Well, it's consistent, right?

MR. SIMPSON: Again, I'm going to ask you --

MR. DES ROSIERS: I'm going to object.

MR. SIMPSON: Just a second, Jared. I'm going to ask everybody to just take a breath. One at a time, please. It's going to garble the transcript, and I don't want that. Now, Jared, do you have an objection?

MR. DES ROSIERS: Well, no, it was just the same thing, that everybody was talking at the same time.

MR. SIMPSON: Okay, okay. Just slow down. We'll get there.

MR. SHOPE: Sure. And let me just rephrase the question because I think we're actually in agreement. And what I'm saying is that this page from the ISO website which reports the 1,000 derate is consistent with what you had read from the independent market monitor which was that there was a derate. Right?

MR. PEACO: No, and as I said, I obtained that information from the chief operating officer's report to the participants committee. What I obtained from the independent market monitor's report was a report that the performance over the tie was a thousand megawatts throughout the period.

MR. SHOPE: Okay, so you believe that your recollection of a report to the committee trumps the data that is published on the ISO website as far as the flows on Phase II on those specific days?

MR. PEACO: At this point it does because I haven't seen the workpapers behind this report.

MR. SHOPE: I'm sorry, you're saying you're doubting the veracity of ISO's report of the flows on those particular days?

MR. PEACO: It's not consistent with the independent marketer's -- independent market monitor's report, and so I have no way to confirm this data over what has been reported in the independent market monitor's report.

MR. SHOPE: Is that report available on --

MR. DES ROSIERS: Sure, it's --

MR. PEACO: Absolutely.

MR. DES ROSIERS: -- Exhibit 107 in this record.

MR. SHOPE: Okay.

MR. DES ROSIERS: Figure 4-3 and page 37 of Exhibit NECEC-107.

MR. WILLIAMSON: What page was that?

MR. DES ROSIERS: It's page 37 of the report. It's reflected visually in Figure 4-3, and the text is right below that figure. We used this report, I believe, with Ms. Bodell.

MR. SHOPE: Page 37. All right, so there is --

MR. DES ROSIERS: The green bar is Phase II, the first sentence under the chart is, I believe, what Mr. Peaco is referring to.

MR. SHOPE: Is that a net tie flow, sir?

MR. PEACO: It's described there as imports over the Phase II line so I'm not sure what you're referring to as net.

MR. SHOPE: Okay, if you look, if you turn it around on its side, do you see that it says net tie flow in megawatts?

MR. PEACO: I'm sorry, I'm not sure where you're wanting me to look.

MR. SHOPE: Okay, so the very figure to which Mr. des Rosiers referred on the top of page 37 of NECEC-107, if you turn the paper on its side, do you see that the description of the green and other bars is average daily net tie flow?

MR. PEACO: I see that.

MR. SHOPE: So in other words, it's taking account not only of what goes in one direction but also what goes in the other direction?

MR. PEACO: I don't see that.

MR. SHOPE: So what's your understanding of the net tie flow, sir?

MR. PEACO: My understanding is it's the net energy delivered into New England across the tie. The first statement below the chart says imports from Quebec, Phase II, were consistent, 1,000, during the year -- during the period. So --

MR. SHOPE: It says about a thousand megawatts an hour. Do you see that?

MR. PEACO: I do.

MR. SHOPE: Now -- I think we have some more points to make, but it's not going to be efficient with the -- just at the moment because we need to regroup. I'm wondering, Mr. Hearing Examiner, whether or not now would be a good time for a break since we've been going --

MR. SIMPSON: How much more do you have?

MR. SHOPE: Not a lot more, but it'll go a lot more efficiently if I can have a short break.

MR. SIMPSON: I vote for efficient.

MR. DES ROSIERS: We're on recross and we have a lot more?

MR. SIMPSON: I understand that, but I don't -- I'm trusting John that it'll be more efficient if we take a break. And based on that representation, I'm going to do it. So let's come back at 3:30.

CONFERENCE RECESSED (January 10, 2019, 3:19 p.m.)

CONFERENCE RESUMED (January 10, 2019, 3:32 p.m.)

MR. SIMPSON: Okay, everybody, let's go back on the record. John, you may continue.

MR. SHOPE: Thanks. So, Mr. Peaker -- Mr. Peaco. Mr. Peaker. Long day. Mr. Peaco, we were looking at Generator Intervener 29 and then we were also looking at the independent market monitor report -- or, I'm sorry, the winter 2018 quarterly markets report by the independent market monitor. And you had referenced the bar chart that's on page 37, and I had drawn your attention to -- which appeared to be, quote --

in the independent market monitor's words, quote, "about a thousand megawatts an hour." And I had referred you to the data on the ISO website that had a range of between 700 and a thousand megawatts. Do you recall that?

MR. PEACO: I recall that.

MR. SHOPE: Okay. And so have you had any chance to look at this and examine it further and understand the discrepancy between the data from the ISO website and at least the appearance on the bar chart, if not the IMM's words?

MR. PEACO: Yes, actually Doug Smith dug into it. I'll turn it over to him.

D. SMITH: Yeah, so I did, in fact, take a look at the morning report page for ISO New England. And this is not a report we use generally, but I took a look at the words that the ISO uses in describing this report, and it says, "Produced daily, the morning report provides the ISO's best estimate of expected capacity available to meet peak power electricity demand and reserve requirements, key parameters used to operate the power system reliability." So my best would be these two reports simply aren't talking about the same thing and that the IMM was talking about energy delivered during a period of time when prices were high and energy was needed and that this was a forward -- this is a collection of forward-looking estimates by the ISO regarding capacity.

MR. SHOPE: Well, I'm looking down, though, at item E in the upper left corner of that same page of GINT-29. Do you see where it says capacity deliveries, net purchases, and then net sales?

D. SMITH: I do.

MR. SHOPE: So wouldn't that suggest that it's actual transaction as opposed to predictions of capacity?

D. SMITH: I can only go by -- I mean, I -- you can estimate deliveries as easily as you can estimate anything else. All I can go by for that is that it's related to capacity, not energy, and what the ISO says about this report.

MR. SHOPE: Okay. Now, you mentioned that there -- we had discussed earlier that there was a derate of the line during this particular cold snap. Do you know who called the derate?

MR. PEACO: I don't.

MR. SHOPE: Okay. Do you know who could call a derate? Would that be Hydro-Quebec or ISO New England?

MR. PEACO: I presume it was -- it may have been due to some sort of equipment failure. So I'm not sure -- operators on which side of the interface would be reporting, but I'm assuming they're coordinated. But I don't know the procedures for --

MR. SHOPE: Okay. So in other words, potentially Hydro-Quebec could have called a derate of the line. Or excuse me, of -- yeah, of the intertie.

MR. PEACO: I'm not sure what you mean by called for.
MR. SHOPE: In other words, declared that there was a derate. In other words, the intertie is the intertie between Quebec and New England here. And so this is an intertie that's managed by the two different system operators, right?
MR. PEACO: The notation in the report to the participants committee -- and, of course, my computer lost the battery so I don't have it in front of me but -- is in the nature of there was an event that caused the line to be derated capacity. I don't think it was a call. I think it was an event that led to them only having a thousand megawatts available.
MR. SHOPE: So in other words, what I meant by call, meaning someone is saying that there has been event or there's something happened and so, therefore, we're going to state that this line is now derated.
MR. PEACO: Well, once the event occurs, I think that's the reality, and the operators on both sides need to understand that.
MR. SHOPE: Okay. Now, during cold snaps, when you have snow and ice storms, you can have sagging on the lines, right?
MR. PEACO: Sagging on the lines?
MR. SHOPE: So in other words, during periods of heavy ice and snow during cold snaps, the power lines can sag,

right, because there's extra weight on the line just the way there was on my windshield yesterday.

MR. PEACO: I suppose.

MR. SHOPE: You're not familiar with that?

MR. PEACO: I don't know that that was the case here. I'm not sure the basis for your question, but --

MR. SHOPE: Well, I'm just asking -- I apologize, we're getting into that interruption which we were both warned against. I'm going to get us both in trouble. Let me back up. So just as a general matter, are you aware of the phenomenon of line sag during periods of snow and ice?

MR. PEACO: Generally, yes.

MR. SHOPE: Okay. And are you aware that that can cause the derating of a transmission line?

MR. PEACO: It could.

MR. SHOPE: Okay. And in the particular case of the derate that we've been discussing back at the end of December of 2017 and the beginning of January 2018, you don't know whether it was snow and ice or some other event that caused the derate.

MR. PEACO: If I -- give me just a second. I don't have the information on the cause.

MR. SHOPE: I think that's it for the public session.

MR. SIMPSON: Any other recross? Jared, any redirect?

MR. DES ROSIERS: No.

MR. SIMPSON: Okay, I think we're at the point where we can take another quick break and go into confidential session. I just want to make clear two things before we do that. First, will these questions include material covered by Protective Order Number 2?

MR. SHOPE: They will.

MR. SIMPSON: Okay. And can I ask who the parties on the line?

B. SMITH: You have Ben Smith on the line, Chris.

MR. SIMPSON: Are there any other parties on the line?

MR. PULLARO: Francis Pullaro.

MR. SIMPSON: Okay. Anyone --

MR. PULLARO: Francis Pullaro.

MR. SIMPSON: Yeah, got you, Francis. Anyone else? Okay, what I'm going to do now is ask the people on the phone to hang up, and Ben and Francis, I'm going to email a four-digit PIN to you so that you can call back in. And we're going to come reconfigure the system so that we can go into confidential session. So we'll do this as quickly as possible. Thanks for your patience.

CONFERENCE IN CAMERA/PROTECTIVE ORDER NUMBER 2

(January 10, 2019, 3:47 p.m.)

CONFERENCE RESUMED OUT OF IN CAMERA

(January 10, 2019, 4:22 p.m.)

MR. SIMPSON: Okay, so I realize we're still in confidential session, but let's just proceed anyway. First, I want to deal with the exhibits that were introduced today starting with the Generator Intervener Exhibits 29, 30, 31, 32, 33, and 34. Is there any objection to the admission of any of those exhibits?

MR. DES ROSIERS: No -- let me just double check this one. No objection.

MR. SIMPSON: Okay, those exhibits are admitted. We also have NextEra Exhibit 40 that was introduced today. Any objection to that?

MR. SHOPE: No objection.

MR. SIMPSON: -- number two in the binder that Brian went through today.

MR. DES ROSIERS: No objection.

MR. SIMPSON: All right, hearing no objections, that's --

MR. DES ROSIERS: I might be getting soft, but no objection.

MR. SIMPSON: -- also admitted. NextEra 6 I believe has already been admitted. That's tab number three. Okay, so that -- is there anything else from today that is left unresolved as far as exhibits go? All right, let's go to the ones that relate to exhibits introduced yesterday or the day before. Mitch, you want to --

MR. TANNENBAUM: They were the Generator Intervener Exhibits 26, 27th -- I'm sorry, 26, 27, and 28.

MR. SHOPE: I'm sorry, is somebody talking? I can't hear.

MR. TANNENBAUM: We are referring to Generator Interveners Exhibits, of yesterday, 26, 27, and 29.

MR. DES ROSIERS: No objection to 26, 27, and 28. I will note yesterday generator counsel passed out a version of Generator 29 which was the -- it had a cover for Energyzt. Today it was replaced, and I assume the version today is to be the exhibit.

MR. SHOPE: Yeah, that should be 29 with the backup data attached.

MR. DES ROSIERS: No objection to the --

MR. TANNENBAUM: Okay, so Generator Intervener Exhibits 26, 27, and 28 are admitted into this proceeding.

MR. SHOPE: I think 29 was also --

MR. SIMPSON: So let's describe 29 because I want to make sure we're all talking about the same thing. My understanding of 29 was that it's a four-page document. The first page has the graph on it titled New England Energy Imports and Exports, Capacity Deliveries, and Megawatts and then there's three pages of backup behind that. Is that correct?

MR. SHOPE: For some reason, I'm counting more pages here. Let's see, I have --

MS. TRACY: I have four pages (indiscernible).

MR. SIMPSON: As do I. I misspoke, I'm sorry.

MR. SHOPE: So let's see, one, two, three, four. Yeah, so the document in total is five pages.

MR. SIMPSON: So in referring to Generator Interveners Number 29, it's that five-page document, one graph and four pages of backup that we're referring to?

MR. SHOPE: Yes, and those are spreadsheets that are indicated to be derived from the ISO New England website. Or taken from the website I should say.

MR. TANNENBAUM: So Generator Intervener Exhibits 26, 27, 28, and 29 and -- right. Which ones are those? Thirty through -- 33, 34. Are those in CMS?

MR. SHOPE: Twenty-six through 28 are in CMS because they were actually I think -- believe admitted -- I believe admitted yesterday without objection. So I presume we should re-file -- or not re-file, file for the first time now in CMS 29 through 34 I guess, whatever's been now admitted as of today.

MR. TANNENBAUM: Right, please. Okay, with respect -- and we understand NextEra is not in the room, but we'll let them know and see if there's any objection. I'm hoping there will not be. Based on the case conference, NextEra deferred several of the exhibits that they had initially proposed, and my assumption is that those exhibits that were deferred that were included in the documents that they provided yesterday can be admitted without objection.

MR. DES ROSIERS: What -- my conversation with counsel is those that were used in the package yesterday that are in the package will be admitted, but they will -- and they may have already done this. They were just going to file the portions of them because some of them are very long, and so they were just going to file the portions that they used. And we have no objection to the admission of any of those. And then they were going to withdraw those that they had identified but did not use. That was the agreement that we had with counsel, and we have no objection to that.

MR. TANNENBAUM: Okay, so those will be admitted into evidence and --

MR. SIMPSON: We have the document that the town of Caratunk conducted cross examination on. One was in a spiral binder, and there was a separate document (indiscernible) that.

MR. TANNENBAUM: My memory is that much of what was in the tab is already in the record as the MOU and the -- and excerpts from the company's filing.

MR. DES ROSIERS: Yeah, so the memorandum of understanding is already admitted as an NECEC exhibit.

MS. TRACY: Tab two is a press release that we've excluded in prior exhibits.

MR. TANNENBAUM: Yes, that's excluded. Tab three is already in the record if I'm correct.

MR. DES ROSIERS: Yeah, that's part of -- yeah, so it's NECEC-9.

MR. TANNENBAUM: Tab four, is this a web page?

MR. DES ROSIERS: It is a portion of the Facebook page for the project, and we have no objection to its admission.

MR. TANNENBAUM: And we'll call that town of Caratunk Exhibit 1.

MR. SHOPE: Mitch, if the exhibits -- with respect to Caratunk exhibits that come in, my only request would be if there was some way when they come in that there could be some indication of what the tab number was just because, as we're going through the transcript, just to sort of follow along and connect things. I mean, I'm not sure that I'm actually going to be citing any of the testimony that Caratunk elicited, but I think just anybody who might would appreciate having that.

MR. TANNENBAUM: That point's well taken, and obviously what we are going to do is issue a procedural order that contains the exhibits that were admitted subsequent to the last one, and when we refer to Caratunk Exhibit 1, we'll put in parens tab four.

MR. SHOPE: That would be helpful, thank you.

MR. TANNENBAUM: So tab five is a newspaper so that is not admitted. There is no tab six.

MR. SIMPSON: Yeah, no, it fell out. It's this which is also in the record I believe.

MR. TANNENBAUM: Yes, that's the NECEC filing so that's already in the record. So this would be Caratunk Exhibit 2, Recreational Hunter and Angler Market Report. Any objection?

MR. DES ROSIERS: No objection.

MR. TANNENBAUM: Okay, so that is admitted as town of Caratunk Exhibit 2. Any other issues?

MS. TRACY: We've got to admit the CMP exhibits from the cross of Tanya Bodell yesterday. So that would be -- taking up on where we left off in our pre-hearing memo, our last exhibit in the pre-hearing memorandum was Exhibit NECEC-98. So we have Exhibits 99 through 109 which were used in the cross examination of the panel of James Speyer and Tanya Bodell.

MR. TANNENBAUM: Any objection? Okay, those are admitted. Are those in CMS?

MS. TRACY: They will be. I think --

MR. TANNENBAUM: They will be.

MS. TRACY: Yeah, we're going to -- I think what we're going to do is we're going to wait and just put them all in in one shot.

MR. TANNENBAUM: That's fine. That's absolutely fine. Anything else? Well, I missed all the fun today, but I'll be here all day tomorrow. Toby, this last section is not confidential even though -- all right, see everybody tomorrow.

CONFERENCE ADJOURNED (January 10, 2019, 4:33 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