STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

HEARING IN RE:

RULES AND REGULATIONS TO
IMPLEMENT A RENEWABLE
ENERGY STANDARD

DOCKET NO. 3659

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AUGUST 31, 2005
10:30 A.M.

89 JEFFERSON BOULEVARD
WARWICK, RHODE ISLAND

BEFORE THE COMMISSION:

ELIA GERMAN, CHAIRMAN
ROBERT B. HOLBROOK, COMMISSIONER
MARY BRAY, COMMISSIONER

ALAN NAULT, RATE ANALYST
STEVEN FRIAS, LEGAL COUNSEL
CYNTHIA WILSON-FRIAS, LEGAL COUNSEL

IN ATTENDANCE

WILLIAM LUEKER, DIVISION
DAVID STEARNS, DIVISION
TIMOTHY WOOLF, DIVISION

DENNIS DUFFY, EMI, CAPE WIND

ALBERT BENSON, DOE

ERICH STEPHENS, PP&L

NUBIA PEREZ, CSG

JOHN FARLEY, TEC-RI

CRAIG EATON, FPL ENERGY

ANDREW DZYKEWICZ, EDC

WILLIAM SHORT, RIDGEWOOD POWER

THOMAS ROBINSON, NARRAGANSETT ELECTRIC
LAURA S. OLTON, NARRAGANSETT ELECTRIC
JOHN WARSHAW, NARRAGANSETT ELECTRIC

GERALD M. EATON, PSNH

DOUGLAS HARTLEY, RIPUC
JONATHAN RAAB, RAAB ASSOCIATES

ROBERT GRACE, SEA FOR RI SEO

(COMMENCED AT 10:30 A.M.)

THE CHAIRMAN: Good morning, ladies and gentlemen. Before we start, I want to point out that our presence on the dias does not indicate that we're superior to anyone here because we're very Democratic in this organization, small that it be, that is. I don't think I have to explain it to anybody.

In re: Rules and regulations to implement a renewable energy standard, Docket No. 3659, notice of technical record session. Pursuant to the provisions of Section 39-1, 42-35 and 42-46-6 of the Rhode Island General Laws, as amended, the Public Utilities Commission hereby gives notice it will conduct a technical record session on Wednesday, August 31st, 2005 at 10:00 a.m. in the first floor hearing room of the Public Utilities Commission, 89 Jefferson Boulevard, Warwick, Rhode Island, for the purpose of reviewing the report and proposed draft regulations to implement a renewable energy standard which was filed by the Rhode Island renewable energy standard, RES, rulemaking group on August 16, 2005. The draft regulations

represent the work of many parties that will be affected by the proposed rules and are intended to assist the Commission in developing and adopting regulations on or before December 31st, 2005 to comply with the legislative mandate of R.I.G.L. 39-26-1, et seq.

The RES negotiated rulemaking group's proposed draft regulations and related documents are on file for examination at the Commission's office and also can be accessed at www.ripuc.org/eventsactions/docket/3659page.html.

Reference is also made to Chapters 42-35 and 39-1 of the Rhode Island General Laws, specifically, Sections 42-35-1, 42-35-2, 42-35-3, 42-35-4, 42-35-5, 39-1-1, 39-1-3, 39-1-11, 39-1-18, 39-1-38 and 39-26-1, et seq.

I might suggest, why don't we start over here and have the parties identify themselves.

MR. LUEKER: William Lueker, Special Assistant Attorney General representing the Division of Public Utilities and Carriers.

MR. WOOLF: Tim Woolf, Synapse, on behalf of the Division of Public Utilities and

Carriers.

MR. STEARNS: David Stearns from the Division of Public Utilities and Carriers.

MR. DUFFY: Dennis Duffy with Energy Management, Inc., Cape Wind Associates.

MR. BENSON: Albert Benson, U.S. Department of Energy Northeast Regional Office.

MR. C. EATON: Craig Eaton, FPL Energy and also EDC.

MR. STEPHENS: Erich Stephens, People's Power & Light.

MS. PEREZ: Nubia Perez, CSG, Conservation Services Group.

MR. FARLEY: I'm John Farley from The Energy Council of Rhode Island.

MR. DZYKEWICZ: Andrew Dzykewicz with the Rhode Island Economic Development Corporation.

MR. SHORT: Bill Short representing Ridgewood Power Management; also the entities Blackstone Hydro, Ridgewood Providence Power Partners and Ridgewood Rhode Island Generation. Those latter three are all generators located within the State of Rhode Island.

MR. ROBINSON: Tom Robinson with Narragansett Electric.

MS. OLTON: Laura Olton with Narragansett Electric.

MR. WARSHAW: John Warshaw Narragansett Electric.

MR. G. EATON: Gerald M. Eaton of Public Service Company of New Hampshire.

MR. HARTLEY: Doug Hartley. I represented the Public Utilities Commission on the negotiated rulemaking group.

DR. RAAB: Jonathan Raab from Raab Associates. I was the mediator for the process.

MR. FRIAS: Steve Frias, Commission counsel.

MR. NAULT: Alan Nault, Commission rate analyst.

THE CHAIRMAN: I'm Elia Germani, Chairman of the Commission. To my left is Commissioner Mary Bray. To my right is Commissioner Bob Holbrook. You're not any relationship to Craig, are you?

MR. G. EATON: No.

THE CHAIRMAN: Let me clarify that for the record. Mr. Hartley?

MR. HARTLEY: Well, I'd like to thank the group. This was a difficult task that required a lot of information in complicated, arcane areas. Our charge, the charge of this group, was to put in place, or to draft regulations for the Commission to put in place to operate a renewable energy standard for Rhode Island which was passed by the General Assembly. The group asked me as the -- its initial facilitator to attempt to find a way to hire a permanent facilitator and we hired later -- got Jonathan Raab on board.

Dr. Raab is going to present an overview of the process and the outcome of the process and then we'll welcome, of course, your questions any time you want to ask any. So I'll -- Mr. Raab? Dr. Raab?

THE CHAIRMAN: Proceed.

DR. RAAB: Just a very brief overview and then we wanted to get right into the meat of the draft regulations. As Mr. Hartley mentioned, regulations were put in place or need to be put in place in order to operationalize the law that

was passed by the legislature. That law, in its very most basic form, requires that electricity suppliers in Rhode Island use an increasing percentage of renewable energy resources in their supply mix out into the future. The regulations and the law grew out of another stakeholder process in Rhode Island which was the Green House Gas stakeholder process, and the renewable energy standard was one of the measures in the Rhode Island Green House Gas Plan that saves the most amount of green house gas and so it was a high propriety for that process. So that's where that -- where this originated.

However, with any piece of legislation, in order to really operationalize it there's a lot of details that need to be worked out in the regulations. So what you have before you is the effort of this diverse stakeholder group to try and translate the legislation into sufficient detail so that it can be implemented. The stakeholder group came together and met approximately eight times since coming together and with a lot of work with various stakeholders between meetings to move everything forward. We

have a list in the back of the cover letter that I've attached of all the group members, and many of the organizations had more than one person participating, and we have their attendance in the -- during the negotiations.

We have before you in the report a draft set of regulations and it also has several attachments. The first attachment, Attachment A, is a model compliance form that the group recommends referencing in the rules but not including in the rules so you have a little bit more flexibility to change it from time to time, but this would basically be the form that obligated entities would fill out to show that they're in compliance with the regulations, and as you see, they're fairly detailed forms. Those forms were actually put together by actually Mason from CSG who we hoped would be here, but she gave birth yesterday to a daughter, so Nubia will be filling in for her.

Attachment B has a few small technical corrections to the law that the stakeholders recognized as we were moving through in a lot of detail the laws and trying to translate them into

regulations and they're technical corrections that the stakeholders recommend that the Commission sponsor a small piece of clean-up legislation that stakeholders would then support to clean those things up.

Attachment C and D both have some memos from the various stakeholders that were actually sent to the stakeholder group on the few issues that were dissenting, and so we'll actually get in more detail on those dissenting issues as we go through the document, but that's what's in Attachments C and D.

I think what we're intending to do is to go through the draft regulations section by section and during the course of that essentially page by page we'll highlight the very few issues where there was disagreement remaining at the end of the process among stakeholders. We'll let the stakeholders sort of annunciate what those differences were and give you a chance to follow-up with them with any questions you have.

We've also had some questions that Cindy Frias had forwarded to me a couple days ago that she had in doing a very careful read of the

draft regulations and we're set up to address each of those questions that Cindy had forwarded to me within the section and we've assigned various stakeholders around the table to sort of take a lead in answering those questions.

I also wanted to just point out in the cover letter there's one paragraph right at the end where we talk about a process between the Commission and the Department of Environmental Management on collaborating together as new regulations in other areas come into effect that would require coordination and sort of careful scrutiny as to how they would interact with the renewable energy standards, most notably, the regional green house gas initiative which would set a cap on carbon for the region which should be finalized over the next month or two. We just need sort of a careful review as to how it interacts with the renewable energy standard.

Before we start section by section, I just wanted to add my own personal observation which is that the stakeholders really rolled up their sleeves and worked extremely hard to produce these draft regulations that you have

before them -- before you, and it really was an attempt to translate the law into regulation and we had to refer often to the law during the deliberations. I think the group was extremely successful.

As you see, there are really very few issues where there was an outstanding disagreement. In some places members found the law to be a bit ambiguous and some of the disagreements are trying to interpret the language in the law, the intent behind that language. In other places there was just a substantial amount of flushing out that needed to be done in order to operationalize the law and that's why the regulations are detailed and relatively complex.

So with that, I guess I would just ask if there's any broad questions before we go section by section through the regulations. Okay. Bob Grace from SEA for Rhode Island SEO.

So just beginning with Section 2, the purpose of the regulations, we're here to just refer directly to the law. Section 3 required a huge amount of work which was to really define

all the terms that are used throughout the regulations and what they entail. I think that the first issue that Cindy had raised that we wanted to address was in Subsection 3.6 on eligible biomass where she noted that we added some additional text that was not in the law and flushed it out a bit further and she wanted just a better understanding about what it is that we were doing, and so I'm going to turn it over to Erich Stephens from People's Power & Light to answer that question.

MR. STEPHENS: Thank you. As Dr. Raab said, we all try to be I think as true to the original legislation as possible even to the extent of on occasions carrying over typos into the regulations as happened in this 3.6, but specifically, to the question about why the extra language and wording here, there are three reasons why we added additional wording in this section, and I dare say probably in most sections. One was to add clarity to a phrase that -- and provide extra definition to it, and by doing that the idea was to reduce the administrative burden for the Commission so

they're not constantly having to revisit issues and also to reduce the expense for developers and ultimately ratepayers. The more clarity in the regulations, the easier it will be to pursue the terms of the RES and meet them ultimately.

The third reason was to provide definitions for terms of use in the legislation but aren't clear what they meant, and finally, I think we added additional language when we identified areas where there were problems or potential problems that had come from ambiguity in other jurisdictions or in other settings.

So turning to 3.6 specifically, we added the terms, the additional examples of clean wood, yard trimmings, site clearing waste, wood packaging. The reasoning for that was simply because the group agreed that these were additional types of wood that were clearly clean wood, and we all agreed that in order to save somebody from having to come back and ask if they were considered clean wood, we would just spell it out right now, yes, they're clean wood, and we also looked to other jurisdictions, what they were doing in terms of examples of clean wood.

Oakridge Labs apparently used these examples as well, so just looking for consistency across jurisdictions to make things easier for everybody.

The second area we had to add language was in relation to the term "other clean wood," and exactly what does that mean, and the whole second paragraph of 3.6 is trying to address that. The other area where we added language was, let's see, I guess it's the last -- second to the last phrase of the first paragraph or sentence, provided that such gas is collected and conveyed, et cetera. What that was addressing was an issue of injecting landfill gas into the existing natural gas infrastructure, pipelines and so on, something that is apparently technically feasible, and in fact, some folks are contemplating doing, but the group felt that given there wasn't enough existing tracking, means of tracking where gas is coming from and experience with injecting landfill gas into the natural gas infrastructure system that at least at this point anyway just to not allow that at all. Just for clarity, and also although some in

the group had policy reasons why we should do that as well, but for policy reasons that's why using landfill gas that's been transported over common carriers was not allowed and that's why that language was added in that section as well. Thanks.

DR. RAAB: Moving on to Section 3.8, again, there was another question about the language we added at the end to the definition of end use customer, and Bill Short, you were going to briefly explain that.

MR. SHORT: Basically, there have been several FERC issues on whether or not a generating unit is subject to taking service retail, whether or not it buys its electricity either from the ISO or from essentially its own plant, whether or not that is a retail sale. These FERC decisions showed that it is not; it's a wholesale sale. We wanted to capture that here in the definition of end use customer so that the RPS percentages would not fall on top of these wholesale trades. We could have left this out. This would have necessitated with respect to Ridgewood and probably FPL, Dominion and the

other generators located in the State of Rhode Island coming in and opening a docket and requesting that the PUC rule accordingly that these were wholesale sales, therefore, not -- and not retail sales, and therefore, not subject to the RPS requirements.

DR. RAAB: Moving on to Section 3.13, Cindy had asked for some further explanation on why we were using Calendar Years 1995 through 1997 and some additional clarifications, and Bob Grace who's joined us since we began from the State Energy -- representing the State Energy Office was going to do that.

MR. GRACE: Thank you. The additional language here is actually part of a -- consistent with a number of different things that were added into the regulations to be consistent with the RPSes that were operating more generally in the region. The statute in many ways reflected consistent or identical treatment to what has been done in the Massachusetts RPS regulations and wherever the -- there was a lack of specifics, we looked to develop some regional consistency. So the historical generation

baseline approach here mirrors what has been done in Massachusetts where the 1995 to '97 period was used as a reasonable historical period for judging historical baseline above which generation will be considered incremental. That's basically the period immediately prior to restructuring.

The other question that was raised was the last phrase of the definition, and this was really added to avoid a critical problem that has arisen in Massachusetts where ambiguity in the statute and subsequent rulings by the Massachusetts Division of Energy Resources resulted in effectively existing renewables being treated and considered as new. It effectively is a very concerning loophole in Massachusetts that continues to be the subject of an ongoing proceeding and a lot of friction. We thought it would be appropriate here to lay out very clearly some language that would avoid that problem here and avoid the Commission having to grapple with those same issues by making it very clear what the definition of incremental generation was, closing the loophole so that existing generation

could not somehow be considered new. Thank you.

MR. FRIAS: Is that existing generation as of 95/97 or is that of generation of right now, today?

MR. GRACE: That is both. This tends to apply in most circumstances and the condition in Massachusetts was for biomass generators that had been in operation prior to '98 as far back as they started developing biomass in New England where if the biomass plants were able to retrofit or change their fuel use and become eligible when they previously hadn't, the baseline had been assumed in Massachusetts to be zero because the amount of generation during '95 to '97, even if the plant was operating fully, wasn't considered eligible in Massachusetts. They had assumed that effectively there was no baseline. So while you could have a plant that was operating fully change some aspect of its fuel use or emissions or conversion technology and all of a sudden without having actually any change in the amount of generation, it was considered to be all new. So that was effectively the loophole we were trying to close.

MR. FRIAS: And so basically any renewable generation existing as of -- you know, in the 95/97 time frame would not be considered incremental or new generation under this RPS. Is that basically what you're trying to close?

MR. GRACE: Correct. So it's only the amount above the amount of generation during that baseline period would be considered incremental.

MR. FRIAS: Okay.

COMMISSIONER HOLBROOK: And that baseline, in other words, is a three-year average, '95, '6 and '7?

MR. GRACE: Correct.

COMMISSIONER HOLBROOK: If you look at those numbers, would it be a rising number each year?

MR. GRACE: It tends to differ. Some plants were actually shut down during that period. Other plants operated at various levels. There's no obvious trend. It appeared -- I was involved in the derivation of this in Massachusetts as well. We looked at that period and it appeared to be representative.

DR. RAAB: So that brings us to the

first issue in which we did not have a consensus, and I think it had to do with interpreting the law and that builds on the issue that Bob was just talking about about when you would -- what you would credit as incremental generation in circumstances for both intermittent renewable resources and non-intermittent renewable resources, and although the group agreed and interpreted the legislation that there basically would need to be capital investments made to increase the electricity generation by at least ten percent, the disagreement among the group was once you have met that threshold, whether you would get credit for all the new incremental generation or only stuff that was above the ten percent threshold, and so I was going to turn it over to representatives from each side just to briefly state the position so you understand it. Bob, you were actually going to do one and Dennis Duffy was going to do the other.

MR. GRACE: The language included in here, the primary version represents the majority of the group's interpretation of the statutory language that effectively takes incremental

output of generation units that have increased their generation greater than ten percent, that's the statutory language, and the plain language meaning as it was taken and discussed by the group was that the intent was for all of the incremental generation above whatever the historical baseline would be to become eligible so long as the generators had met the test of increasing its generation, its annual output capability by at least ten percent.

While the other interpretation Mr. Duffy will describe may also be a reasonable one, the majority of the group simply felt that was not what the statute allowed.

DR. RAAB: Mr. Duffy?

MR. DUFFY: Thank you. Just very briefly, it's a very simple question of statutory interpretation. We look at the operative phrase for eligibility for incremental resources as the incremental output of generation units using eligible renewable energy resources that have demonstrably increased generation in excess of ten percent.

Now, we take that to mean that not only

would there have to be a capacity expansion of the unit of ten percent, but also an actual increase of ten percent above the baseline in the energy produced, and that's the real difference. We would make the threshold for eligibility on that increment be a ten percent increase in the capacity of the unit but also an actual ten percent increase in the energy output, and that's really the extent of our difference of opinion.

DR. RAAB: I promised any stakeholder that wanted to add something have that ability if they felt it necessary.

MR. SHORT: Let me pass these up so they can read these comments as I go through them on the ten percent. I'd like to speak in favor of essentially what Dennis has said with a clarification.

DR. RAAB: Go ahead.

MR. SHORT: My name is Bill Short, and basically, I'd like to clarify I think what Dennis was saying and make it more clear with respect to Section 3.22(v) and then I'll speak on 3.22(vi). We believe that essentially there should be what we call a 110 percent test, and

that's actually the first item in the handout that I've passed out. Sorry I didn't make enough copies for us all, but basically, we have -- we believe that the generator should have to demonstrate that it made 110 percent above its historical baselines. That's the absolute minimum. In addition to that other comment that Dennis has hit upon, and he largely put in himself, was that we have to demonstrate an increase in efficiency and/or an increase in capacity. Those are the two tests. That's how we interpret and read the statute.

For example, the Johnston landfill which we own has an historical baseline of about 87,000 megawatt hours. In order for us to get any new renewable generation credited from that facility, No. 1, we have to demonstrate either an increase in capacity or an increase in efficiency. Okay? That's the first and most important thing. Since we have a relatively constant fuel supply, we then have to demonstrate that we could produce another ten percent of energy above that. That's roughly 8,700. To the extent we generate above that 87,000 plus the ten

percent above, that we would get new renewable certificates above 87,000. Okay?

The -- 3.22(vi), all we have asked for here, and we own 16 hydro electric sites scattered around New England, so we're very concerned that this issue be adopted also. We need to supply a three-year trailing average to the current year's production. Our variation from our hydro electric sites is as much as 30 percent in any one year. So we have to have essentially the increase in efficiency, the increase in capacity as well as also a trailing three-year ten percent increase in generation and we've added that in yesterday to the proposed language here. It captures what we think is the spirit. We believe that we have to produce this ten percent above in order to get any credit above the historical baseline. Thank you.

DR. RAAB: I think Bob Grace wanted to clarify one thing and then if the Commissioners had any follow-up questions.

MR. GRACE: Just as a matter of clarification, I believe the group did reach consensus on several of the points that Mr. Short

mentioned in terms of the need for an efficiency improvement or additional capacity. I think the real distinction between those two positions comes down to whether the amount of energy between 100 and 110 percent is eligible, and that's really the only disagreement or difference between these two positions, and I think Mr. Duffy and I would agree that it really comes down to statutory interpretation.

MR. DUFFY: I would agree.

DR. RAAB: Any further questions on this?

MR. FRIAS: Not myself, and I don't think the Commissioners have been involved in this level of nuance.

THE CHAIRMAN: I want to know what the economic differences are, because I want to know what's behind the words? Okay? Can someone address that?

MR. SHORT: What the economic --

THE CHAIRMAN: Yes. Why is one group taking one position -- I mean, it's all economics. Let's not kid ourselves.

DR. RAAB: John, go ahead.

MR. FARLEY: I can address that from the ratepayer point of view. To the extent that you eliminate generation from being eligible for new renewable resources, you create more scarcity for that product which the consumer has to buy and to the extent there's scarcity, that raises the price and in the event that there's overall scarcity, it means that the alternative compliance payment which is going to be in excess of $50 per megawatt hour would be paid by the consumers. So this to the extent that it's reasonable to interpret the statute such that that increment between 100 and 110 is, in fact, eligible, it increases the amount of supply available in the marketplace to be purchased.

DR. RAAB: I'll just see if any other stakeholder wanted to add that hasn't added yet. Okay. Dennis?

MR. DUFFY: Just very briefly in response to the Chairman's question. I think John has accurately described the implications of any expansion or contraction of eligibility. The way really to look at it, though, is -- one way to look at it is does it drive down the price to

the benefit of the consumer, but from the flip side, from the -- from people trying to develop renewable resources and attract capital to the market, a reduction in the value of renewable credits through expanding eligibility can be interpreted as a weakening of the price signal that's meant to incentivize new investment, and that's the real purpose of the act.

MR. FRIAS: Could I ask a clarification, because I hear about trailing per year averages and capacity. I want to narrow the issue a little bit clearer for me at least. Basically, the difference, Mr. Duffy, you want the credit for anything above 100 to 110?

MR. DUFFY: No. My position is that your capacity should qualify as eligible only if it's above the 110 percent. That's my position.

MR. FRIAS: Thank you. Bob, your position is you should be eligible if it's 101, you get the credit for the one?

MR. GRACE: Yes. So long as it has met the test, the statutory test that it has to increase its ability to produce by at least ten percent, then any given year anything above 100

percent would be eligible.

MR. FRIAS: So say you're basically -- I'll get to you in a second. Basically it's sort of I make -- let's say I'm 111. Basically under Mr. Duffy's you would only get credit for that last point --

MR. DUFFY: Correct.

MR. FRIAS: -- above 110. While under your scenario, Mr. Grace, it would be you get credit for everything above 100 through the 111.

MR. GRACE: That's correct.

MR. FRIAS: That made my math a lot simpler. I'm not an economist.

THE CHAIRMAN: What's the purpose of the ten percent in the statute then? What's the purpose of it?

MR. FARLEY: Well, I think the purpose of it is to eliminate the noise factor. If everybody is 101 or 102, it's arguable that they really have an increased capacity, so it's a threshold to assure that there's been a substantial increase, and according to our point of view, everything above its historic should be as incremental new.

MR. SHORT: Basically, our position is somewhat in the middle. It's roughly -- let's go back to the example of 100, 110 and 111 and 101.

THE CHAIRMAN: Are you the Justice O'Connor in this group?

MR. SHORT: I'm the Justice O'Connor in this group. As I read Mr. Grace's position, one -- if you produced 101, you get one. Under Mr. Duffy's position and my position, you produce 101, you get zero. What we say is that you have to get to 110 in order to get anything above 100.

COMMISSIONER HOLBROOK: Mr. Grace, did you have a caveat on your position so that in order to get the one if you do 101, something else has to occur as far as efficiency is concerned?

MR. GRACE: Effectively the way that the majority of the group envisioned that this would work was a two-step process. Effectively a plant would have to demonstrate to the Commission during the verification step that it had made the necessary changes to efficiency or capital improvement that would allow it to increase its output in any given year by at least ten percent

given whatever its input. So if it was a hydro plant with the same amount of rainfall would produce at least ten percent more than it would have in the past, for example. And once that certification step had been made, then there would be a simple determination of what historical generation would be, there would be a number, X megawatt hours, and simply in every year you could compare the actual production against that X megawatt hours, and if it exceeded that, then the excess would be considered eligible. I guess I'd like to reiterate that I don't think the group as a whole felt strongly one way or the other as to whether one position was better than the other, just the majority of the group seemed to feel that the more accurate interpretation of the statutory language was the position that I've been asked to represent.

COMMISSIONER HOLBROOK: And the economic benefit of having credit for more rather than less is what?

MR. GRACE: It would tend to be lower cost to ratepayers.

MR. FRIAS: Just to ask more about this

economic scenario. Basically, you'd make more renewable sources eligible for the RPS standard if you had this -- what I call 110 retro back to 101, right?

MR. GRACE: I think the number of sources or the number of plants would be exactly the same. You still need to meet the basic test of having increased, but once that number of plants has been certified, you would have more renewable energy credits or certificates under the position that I've described.

MR. FRIAS: Therefore, it would be easier for -- it would be more likely there would be -- that we'd be reaching the statutory thresholds every year under your scenario.

MR. GRACE: There would certainly be more supply, so I guess you're statement would be accurate.

MR. FRIAS: I'm trying to figure out what the bottom line is on this. So under your scenario there's a greater likelihood using the 110 retro back to 101 of reaching the statutory threshold. Mr. Duffy, your comment is you're talking about the economics of it from a capital

investment perspective.

MR. DUFFY: Right.

MR. FRIAS: What is the -- what is your concern about not -- what's the problem from a capital investment perspective?

MR. DUFFY: And the question I was responding to is what's the real economic impact here. I think that's what we're getting to. Any time there's a question as to widening or tightening eligibility, it goes right to the value, which obviously affects the price that the consumers will pay, but it also affects the revenues that an investor in this field would see. So I mean, that's ultimately where we come down to the two sides of the same coin. Not only do we want there to be sufficient price signals to be able to attract capital, but we're also very concerned that there be a stable and predictable level of pricing in these markets, and one of the places in other jurisdictions where we've seen a lot of uncertainty is when -- the extent to which older plants are able to do retrofits or rehabs and become eligible. So to the extent we can be as clear as possible on that

point, we think it's -- it allows us to give greater comfort and clarity to our lenders.

DR. RAAB: If there are no other questions from the Commission on this, we'll move on. The next question you had was on Section 3.26 and 3.28. We added a term, prime mover, which was not in the legislation, and we were asked why we had done that, and to respond to that, Gerald Eaton from Public Service New Hampshire was going to explain that.

MR. G. EATON: Good morning. Public Service Company of New Hampshire owns and operates a generating station in Portsmouth, New Hampshire that has three coal fired units of 50 megawatts. We're currently building a new boiler, or Unit No. 5 at Schiller which will burn wood chips, and much of what the group worked on was what to define a new generating unit to be. The statute says it comes on line after 1997, however, this unit when it's completed will have a 50-year old turbine generator and a brand new boiler. We're building the boiler out in open space and at the beginning of the year we will turn off the old coal boiler and essentially pipe

the steam from the new boiler into the existing turbine generator, so is that a new generating unit or not?

So that in Section 3.21 there's quite a bit of detail of what constitutes a new generating unit and we -- our project fits under the repowered generating unit which is defined as -- in Section 3.21. And in order to be a repowered generating unit you have to replace your prime mover, and in our case for a biomass facility we're replacing the entire boiler and making a substantial investment, especially compared to a plant that's -- that's been depreciated since 1957 with capital improvements but it's still pretty much depreciated, but it's going to be a large investment and we'll meet the tests in Section 3.27 of increasing our tax basis and also doing it in compliance with emission rules.

So the prime mover is what an existing generating unit has to replace in order to be considered to be a new generating unit and making the substantial investment that's necessary and promoting new technologies and not necessarily

rewarding existing units for just putting a paint job on the plant and qualifying as a new unit.

THE CHAIRMAN: How much -- what's the dividing line between new and not new?

MR. G. EATON: I think at least for our plant is we're changing the fuel that we're using and we're making a substantial investment to do it. It's not simply -- our boilers right now are capable of burning both residual fuel oil and coal. So therefore, if for some reason one of those fuels was considered to be renewable, just without making any investment, we become eligible to receive renewable energy credits out of that unit. But by making a substantial investment, by replacing essentially the driver of the steam that makes the energy in the turbine and using a biomass fuel that's eligible, that's the dividing line. And you can use existing electric infrastructure such as the turbine and the electric generator, but essentially, you're switching over from a non-renewable source to a renewable source or replacing the existing renewable source with substantial investment that qualifies as a new unit.

MR. SHORT: May I speak?
DR. RAAB: Were there any other questions on that?
COMMISSIONER HOLBROOK: Would the boiler be any different if you had a different fuel? I mean, you're switching from one source to another by changing from, what, coal to wood chips, and you say you're putting in a new boiler, and that should qualify as an investment. But if you -- I mean, what does the boiler do? It creates a steam that runs the turbine.
MR. G. EATON: Yes.
COMMISSIONER HOLBROOK: I'm just trying to see if that's something unique or if that's not so unique.
MR. G. EATON: Well, it's --
COMMISSIONER HOLBROOK: What is the boiler -- I guess my question is what does the boiler have to do with the conversion of your source of fuel from coal to wood chips?
MR. G. EATON: Well, there's improvement in efficiency which is required by other states as well that --
COMMISSIONER HOLBROOK: But would that

be the same result if you continued to use coal instead of switching to wood chips?
MR. G. EATON: There would be an improvement in efficiency but it would not be a renewable fuel, and therefore, would not qualify for renewable energy RECs to be sold in these markets in New England. It's a change over to the fuel and efficiency and lower emissions resulting from that so we're making substantial improvement in emissions as well as efficiency improvements by having a fluidized bed boiler burning wood after the project is complete.
THE CHAIRMAN: Is that a question we must consult with St. Thomas Acquino on?
MR. G. EATON: No. It's a process where we would -- once the plant is completed, we would apply to be certified as an eligible generating unit to sell RECs.
THE CHAIRMAN: To put Commissioner Holbrook's question maybe the same but a little differently, you're changing the boiler which you would have changed anyway to make it more efficient. What's the significant change that's going on here, real significant? Let me ask this

question. If you're changing a boiler which can burn either coal or wood chips but now you're going to be burning wood chips and therefore it becomes renewable. Is it that?
MR. SHORT: No, that's not it.
MR. G. EATON: No. The boiler today can burn coal or oil.
THE CHAIRMAN: Okay.
MR. G. EATON: We are putting in a wood fired boiler as a commitment to renewable energy to purchase wood chips from New Hampshire suppliers. As many of our biomass facilities are coming to the end of their 20-year rate orders, it's not known whether they will continue. So there's a wood chip industry in New Hampshire that Public Service Company is also supporting through this project. We're lowering emissions which we need to do. It will produce far less sulfur dioxide, nitrous oxide than coal does and we may not replace that boiler absent this market and absent these other considerations, because we're not increasing our generating capacity, we may not replace that boiler. If at some point it's more expensive to replace it, then -- and

prices the product out of the market. The renewable energy market and the RECs that we can generate makes this a cost effective project for our customers as well as our company.
DR. RAAB: I think Bill Short and Bob Grace wanted to add something to this.
MR. SHORT: With respect to what Public Service New Hampshire is doing, they're taking a conventional 50 megawatt coal fired plant which essentially has a coal fired boiler which can burn oil in lieu of essentially the coal, the coal is pulverized, blown in and combusted, and obviously, the gasses go up to the top of the furnace and they heat up the tubs. That's being replaced. Adjacent to it they're constructing a fluidized boiler, totally different design. They will feed in the wood chips, they'll sit on top of a molten bed of sand, they'll be combusted. You could burn coal. You're also able to feed in along with that things like lime so you control sulfur dioxide emissions. Because they're switching from coal to wood, the sulfur dioxide is diminimus. Given that it's a fluidized bed, emissions will be reduced dramatically from the

boiler that they currently have. In addition to that the facility will also contain air pollution control facilities such as SNCR, that's a selective non-catalytic reducer and that's a NOX control device to reduce the NOX emissions below certain levels. Roughly this boiler today could produce five pounds of NOX an hour. It will produce about one pound of NOX.

MR. HARTLEY: If the Commission would like to see some wood chips, it just happens that we have some handy.

MR. SHORT: This boiler conversion represents a major technological advancement in New England for the combustion of wood and it would be if we were building old coal fired power plants where we would be taking coal fired power plants. It's a meaningful reduction in our emissions over what this plant does currently emit and it's a meaningful reduction over what 1980s technology stoker plants, wood fired stoker plants. I think it's a good idea, what they've done.

COMMISSIONER HOLBROOK: Could you convert to wood chips if you did not convert the

boiler?

MR. G. EATON: We could convert to wood chips, however, the 1980's technology would not qualify us for renewable energy certificate sales in Massachusetts so the technology change is significant, that it has to be -- you can't go from a gas guzzler to a wood guzzler, you have to get a more efficient boiler out and that's the difference between the stoker technology to the fluidized bed.

COMMISSIONER HOLBROOK: In order to get all the benefits and all of the efficiencies from converting from coal to wood chips the new boiler really from a technological point of view and efficiency point of view is essential. Is that a fair statement?

MR. G. EATON: Yes, in order to participate in the market across the region.

COMMISSIONER HOLBROOK: Just out of curiosity, what is the value of the investment to the conversion?

MR. G. EATON: In addition to the boiler we're building a wood processing facility which was not there before that has the

capability of unloading three trucks at a time and we're spending $75 million to do that combining the project of the boiler and the wood processing facility. And we will probably burn 400,000 tons of wood a year.

MR. GRACE: Chairman, Commissioner, if I could elaborate on this, I think perhaps addressing this line of questioning more generically might be illustrative. The reason that the group came up with this language on repowering more generally which the prime mover language is only a part is returning to this primary question of new versus existing which has tended to be perhaps the most controversial in other renewable portfolio standards, and the group attempted to and did reach consensus on a bright line that would define what constituted new or what did not constitute new.

It's widely accepted that a repowering is effectively a new plant on the site of an economically obsolete plant, that it's effectively societally efficient to use some of the ancillary facilities, the site, the transmission and other facilities rather than

having to site a green field plant where there had not been one previously. Generally, the repowering standard effectively we borrowed from language that has been used and adopted in California under similar circumstances to identify what really constituted a new facility, and in doing so I think we have tried to simplify things for the Commission so that you would not have to deal with a plant-by-plant analysis which has considerable ambiguity. Here we've got a tried and tested bright line that the entire group was able to get consensus on.

DR. RAAB: So that concludes what we had on Section 3. Unless there are any other questions from the Commission, we'll move on to Section 4.

Section 4, there was just one issue flagged for us and that has to do with maintaining the standards for no less than 10 years if at some point they're going to be canceled, and Bob Grace was going to explain why that language was added.

MR. GRACE: Thank you. The language that was added here effectively was intended to

elaborate on the term in the statute indefinitely, that the standards would be in place indefinitely after they -- after the escalation had ceased until the Commission determined that such maintenance was no longer necessary. The reason for this was to inject some clarity and reflecting attempt in the statute to remove the specter of regulatory uncertainly. That type of regulatory uncertainty as to exactly when the standard might be eliminated or decreased creates a significant disincentive for investment in new renewable plants which works to the detriment of both investors, and ultimately, to ratepayers who are disadvantaged by having less generation and therefore a tighter supply, higher costs.

The approach here reflects best practices in studies of portfolios nationwide and effectively creates the ability for investors to know a minimum amortization time for their investment. In the absence of such language, investors verified answers, particularly debt financiers would always have the fear that one year later after reaching the last of the

increases the RPS could be done away with and that they -- most of the plants are very capital intensive, require debt and amortization of their fixed costs over a fair period of time. Without that certainty that they would have that period of amortization, it would be very difficult to attract investment into these plants.

To give an example of what the absence of this language might create as you approach 20 -- 18, 20, 19 years, the incremental demand, the targets step up by a significant percentage, investors in plant to meet that percentage would have no confidence, no -- nothing to rely upon to suggest that they would be able to sell those certificates for more than a year or two and in that environment you would either have extremely expensive cost of compliance or to building at all. So we are attempting to have some clarity here to reflect the objective.

THE CHAIRMAN: Does that conflict with the Commission's ability to back off on the standards?

MR. GRACE: No. The statutory ability to back off on the standards really reflects a

slowing down of the increases. The statute does not allow decreasing the standards from where they're reached; it simply allows stretching out the time line or delaying further increases. So there is the difference between delaying further increases versus actually decreasing from the percentage standards.

COMMISSIONER HOLBROOK: Does that mean if the market doesn't respond, then the target date of 2020 could be pushed off to 2023 or 2025?

MR. GRACE: The language pertaining to that is in the previous paragraph, 4.4. The statute has identified two periods of time to look at the dynamics of supply/demand and make those decisions as to whether to delay the increases.

COMMISSIONER HOLBROOK: I'd be surprised if there's an answer to this question, but -- and I can appreciate the work that has gone into this effort. Does anybody have any idea of the total incremental cost of the program of the mandate from the legislature, I mean, to achieve a goal in 2020 of 16 percent? Does anybody have any idea how much this will add

incrementally to the cost of power to ratepayers? Is it a billion dollars? Is it $20 billion? Is it -- has anybody attempted to make an estimate?

MR. GRACE: I believe the -- there were analyses done at the time that the model legislation was developed by Tellus Institute although the ultimate legislation reflects a different set of rules and that was several years ago so the circumstances are different. I wouldn't put an overly large amount of credence in that. I think the answer is we know that the costs are bounded between the alternative compliance payments, ACP, in the statute and zero and they could be anywhere between those. Over time I know Mr. Short has been involved in some analysis of supply and demand and I'm -- as I have in the past. These things consistently shift. I don't know if there is an answer, but I notice Mr. Short wanted to chime in on that.

MR. SHORT: With respect to the cost, it's clear that if -- essentially if you only look at essentially what the certificate says, those ACP payments, maybe it looks like a large cost. Offsetting that cost is obviously

increased capacity which -- increase in supplies which will probably be offered to the market at a zero cost and therefore essentially save all of us reduced energy costs, improved air emissions, for example. These all factor in as well as also but not least the fact that fossil fuel that is currently being burned in power plants will be available to fuel our homes and factories.

When you look at those offsetting values, the cost of RPSes have come in essentially, and New York was the best example, was six percent RPS. When factored across the board under a $4 cost of gas was a one to two percent increase in retail rates. Under a high cost of gas and that cost of gas was at $6 an mcf, that cost basically was cut in half, so it was roughly less than a one percent increase. If you go to today's cost of natural gas, probably the RPSes have net benefits, not net costs to the consumer. We may have no other choice to go down these roads in order to minimize the cost impacts to ratepayers over the next 10 to 15 years.

MR. FRIAS: Just a general question to follow-up on what Commissioner Holbrook was

asking, then I have another one to get to the point of this paragraph. We understand the RPS was passed by the legislature, they weighed the costs and benefits and costs and all the pluses and minuses. That's not what I think Commissioner Holbrook's question is. If the supply does not emerge, this is the question, if the supply does not emerge from the renewable side, what is the estimated cost if we have to do all these compliance costs? I mean, Massachusetts is having some problems with meeting its RPS standards. Everybody at the table knows that. So what is the estimated cost if the renewable -- we have a party and nobody comes? Okay.

MR. FARLEY: I'd like to take a stab at it because some of our members are going to be paying that. If one assumes that we're in alternative compliance for a good portion of the incremental cost, and I think that's not an unrealistic at least conjecture because, in fact, the increase in Rhode Island far exceeds the increase in percentage over what's currently available for these other states that have used

these examples. So if one were to just simply take that 16 percent and apply it to the gigawatt hour consumption in Rhode Island which will be growing over time and also the alternative compliance dollar per megawatt hour which I believe initially was at $50 but increases with the cost of living, one can conservatively estimate that the incremental cost by, say, 2018 can be something in the order of $100 million a year of incremental funds from ratepayers.

Now, I agree with Mr. Short. If, in fact, that money is being targeted to influence incremental generation, then it will be offset by the benefits of that generation, however, if it's not, then it is questionable what benefits are being accrued, and therefore, it really is a cost without an offsetting benefit and that's why it's so key that this is designed towards bringing new incremental generation and making this a market that works.

MR. GRACE: Sir, the answer to your question is a calculation that I have made in the past for the Standard Energy Office. I do not have those figures with me here but I'd be happy

to provide them.

MR. FRIAS: The question I have for you, Mr. Grace, at the end, so I can understand this last paragraph, or last phrase in it. In no event will the standard be maintained for less than ten years. Is it basically saying that come the year 2020, the Commission, regardless of anything else, is required to keep this standard going through 2030?

MR. GRACE: That would be correct.

MR. FRIAS: And the legislature intended this to be in effect through 2020, right, at least, or indefinitely?

MR. GRACE: The legislature had intended for this to be in place through 2020 and then maintained indefinitely until the Commission found that such -- that maintenance no longer was required.

MR. FRIAS: Basically your request to the Commission is please tie your hands for 2020. I'm just asking you.

MR. GRACE: I think that is a fair representation.

MR. FRIAS: And that I just wanted to

clarify.

THE CHAIRMAN: That's the question I asked earlier. Were we restraining ourselves and the answer then was no, but now it's yes.

MR. FRIAS: When you do cross-examination, sometimes it comes out that way. So basically, the legislature intended this to be in effect 2020 and gave the Commission discretion after that, but this proposal would tie our hands for at least ten years every year subsequent to that. So if we do nothing in 2022, it's 2032 and henceforth, is that correct?

MR. GRACE: That is correct.

MR. FRIAS: That's all I needed to know. Sorry.

DR. RAAB: Something else on this?

MR. SHORT: I'd like to give everyone a firsthand example of what I call this type of sunset that Bob Grace has tried to highlight for us and essentially tried to avoid. In the Connecticut RPS they have -- their DPUC has ordered -- has ruled that their RPS sun sets on December 31st, 2010. That specific question was asked by the Union of Concerned Scientists in the

rulemaking in 03-1018 or 19, that's the docket number, and that's precisely what they came out with. Therefore, with respect to Ridgewood's interest, to the extent we build any generation in New England to serve the Connecticut RPS market, we also make sure that that generation has to be qualified in Massachusetts, for example, and then Massachusetts new or the Rhode Island new RFP requirements. Otherwise, in 2011 our market, if it's only a Connecticut market, disappears completely. We could never raise money from equity investors, and I am sure that the other people who are looking to develop could never raise a dime from debt investors if they had such a short time horizon to recover their investment plus also a profit on that. Thank you.

MR. FRIAS: Could long-terms contracts address that issue better than that?

MR. SHORT: Oh, yes, with respect to if you had an RPS end in 2010 versus a ten-year contract you sign in 2008, yes. I think that's your only option.

MR. DUFFY: I'd like to concur with

that because not only would it give you surety as to the duration but it would also give you surety as to the level of compensation for a longer term.

MR. C. EATON: We concur with that also.

MR. FRIAS: I know you're going to get there. I'm sorry. We were talking about long-term costs and that just came to my mind.

MR. SHORT: Yes. We will have another set of nuances to discuss.

DR. RAAB: So moving forward to Section 5 on eligibility, the group was in complete agreement on the language and no questions have been posed to us at this point. So if there aren't any other questions on eligibility, we'll move on to Section 6.

Section 6 deals with certification, and this brings us to the second issue where we didn't reach complete agreement and Erich Stephens was going to talk about what the issue is and lay it out for you and also then describe why his group was representing one position and I will turn it over to somebody else to represent

the other position.

MR. STEPHENS: Thank you. If I could, I did a diagram to try to explain a somewhat complicated issue, if I could just pass this up. When you see this diagram, you'll see that there's Option A at the top, Option B at the bottom. Let me start by explaining what the purpose of all this language is. The legislation allows for -- well, behind the meter and even off the grid generation to account towards the renewable energy standard so long as that generation is located here in the state. Presumably these will be relatively small generators, PB systems on homes and businesses and so on, for example. So the question becomes how to account for the generation from these units in a way that is cost effective for the generator and in a way that's efficiently administered and overseen both for the sake of reducing administrative burden for the Commission but also to reduce costs and hopefully reduce costs for the ratepayers.

So given that, what came about was this idea of forming an aggregation of these smaller

generators and then that aggregation of smaller generators would then be treated for the purposes of regulatory compliance and GIS inputs and so on as a single generation unit. In other words, lots of small generation units if formed into this aggregation would essentially become one larger generation unit, and there's all sorts of requirements for how that would be done that are identical in both Option A and Option B.

So given that, perhaps it would be best if I explained sort of where we are now. If no new rule were put into place, and the easiest way to visualize is look at Option B and cover your hand over the little verifier person down there. This is where we stand now. In fact, it's already in operation in Massachusetts where you have these small generation units reporting their generation to the aggregator, that is, the people who actually own the renewable energy certificates and therefore get the financial benefit of it. The aggregation owner literally inputs that reported generation into the generation information system themselves, it's done right online over a website actually, and

then once those REC certificates are in the GIS they can be used for compliance. And so that's why I showed the little dollar sign going back to the aggregation because I think it's important to keep in mind, again, getting back to the question what is the economic question here, the question is the aggregator ultimately gets the economic value of performing this aggregation, and therefore, the amount of generation from the aggregation.

So given that, we identified two ways that this could be made more robust to improve confidence in the system. Clearly, no one really felt good with having the aggregation basically sort of self report on the generation that they're going to get economic value for. The first idea that came up actually was Option A, and basically, the idea here is that instead of the generation units reporting their generation to the aggregation owner, it would go to a third party and that would be an independent third party not having any financial relationship to the aggregation, and in fact, wouldn't even be compensated by the amount of generation from the

aggregation so there would be no reason for the verifier to have any reason to misstate or misrepresent the generation from the different units. And then that verifier would actually do the meter readings and would enter the total output of the generation units into the GIS which would be used to create RECs and meet the RES. This was thought to be a relatively straightforward, clean way of doing this. It would have reduced administrative burden for everybody, but most importantly, perhaps it would be a very trusted way of accounting for generation for these smaller units.

The only issue became -- I think it's fair to say the only issue that people had in the members of the group was that the current configuration of the GIS system right now, the actual technology, the website I mentioned, doesn't allow this to happen. The only people that can enter the RECs into the GIS right now is the generation -- is the aggregation owner. So folks that were supportive of Option A said that's fine, we'll just have the GIS system change the website. It's not that big a deal,

and Ms. Perez can speak more about the technology change that would be required. It really would be a simple question of allowing the verifier to have access to a particular screen without access to the full account that the aggregator would have. However, there were folks in the group that felt no, we don't want to be requiring the GIS to make changes, and what they were saying is Option B down at the bottom, yes, we need to have this third party verifier, but their role is sort of an accountant, doing an audit, they would oversee the process that the aggregation puts in, list and make sure that they're entering accurately the output of the aggregation.

So that's sort of an overview of the two issues and I'll put in a plug for Option A. We'll be hearing from Option B. Basically, the GIS system was developed to serve the purpose of efficiently meeting these various regulations, be they renewable energy standards, be they emission standards, be they source disclosures or emission disclosures on bills and so on. And so it seems they are effectively reasonable and in fact proper for the Public Utilities Commission to say

to the GIS, you know, put this change in place. This is the regulation and your job is to make the change necessary to make the regulation work and the costs of that would be minimal is what I heard from -- actually from -- actually Mason who couldn't be here as we heard, but she was very familiar with the technology behind it and she concurs that the technology change is really not a big deal, it would not be costly and it's really just a question of getting training and the bureaucracy at the GIS to get the change in place. And so given that the change needed is a simple one technologically and given that having a third party verifier actually enter the generation themselves instead of having to go through a lot of hoops to oversee aggregators doing it and given the importance of developing a trusted and robust and confident market in the RECs, for all the reasons, we've been hearing about economics and so on and making sure ratepayers are getting what they pay for, we think that's where we should go is basically with Option A.

DR. RAAB: Before I turn it over to

Bill Short to talk about Option B, I want to say there was one other subissue which two of the four parties that supported Option B supported which was to also limit the verifier to be the electric distribution company so that is a subissue, it wasn't noted in the cover letter but is noted in the text, so Bill Short will speak both to Option B and then also the subissue about the verifier being limited to the distribution company.

MR. SHORT: Thank you, Jonathan. I'd like to with respect start actually with the last issue which is who can be the verifier. We believe that the verifier should be electric distribution companies. We have looked into this issue with respect to Massachusetts. Massachusetts Electric, an affiliate of Narragansett Electric, reads meters with respect to load response programs. They charge a $12.50 a month, $250 for their time to read load response program meters. These meters would be very similar to what would be read here. We see no reason given the fact that we can have an organization that will be around for as long as

Rhode Island is around as far as we're concerned and in a position essentially that has a meter reading group and has set clear standards, we think they should be the type of entity that should be allowed. There are clearly electric distribution companies that can step into this. We view what is being talked about here is essentially a one or two person organization. This is going to be their portion of their job. They're going to have to rely on revenues from other sources, since this idea has first come up about a year ago at the NEPOOL GIS it moved into essentially no relationship between an aggregator and verifier. The fact that no type of compensation to the verifier can be volume related to reading the meters, we believe those issues are easily passed by by simply mandating that electric distribution companies be the sole type of entity to read such meters. That's our first point.

Our second point goes to Option B. When there was an extensive amount of discussion at the NEPOOL GIS operating rules committee with the exception of really conversion services there

was really no support for Option A. This thing was -- this issue wasn't sent over to the meter reading working group of the New England Power Pool and as a result of that the issue was essentially tabled. This is an attempt to come back through here, come back through this proceeding, reopen this issue and essentially create what I call the equivalent of a constitutional crisis and therefore the GIS will be forced to change. There is no reason after extensive debate to change essentially from Option B to Option A. Thank you.

DR. RAAB: Any other stakeholders want to comment on this? Bob and then Craig.

MR. GRACE: I'd like to just address the first point made by Mr. Short about who would be the verifiers. The Energy Office has through its activities administering the renewable energy fund two perspectives here that conflict with that perspective of the utility being the meter reader. One is the fund has invested in or supported many of the small generators that would be qualifying under this approach and through that investment or through the fund programs

there is metering infrastructure associated with many of these projects and will be through the future. To mandate that some other entity be the metering entity would effectively duplicate unnecessarily the infrastructure that the fund has already built and that the small generation community has invested in, and that is not to the ratepayers' benefit to duplicate metering and data collection functions.

The second point is the fund through its activities is aware of several businesses that have been formed and that can very efficiently collect data from small generation sources of this type, far more data than is needed for this particular purpose, but it is used to support additional purposes of program support and reporting and that these businesses can be very efficient and cost effective in doing so. So to mandate that the utilities step into that role effectively stifles the growth of these businesses which seem to be able to provide competitive service at a better price.

DR. RAAB: Craig?

MR. C. EATON: Yes, just quickly. FPL

Energy wants to support what Mr. Short said quickly on the verifier. We feel the same. Narragansett Electric, this is what they do, this is what they know and they certainly can be trusted. On Option A, Option B, Option -- you see with Option A you're going to have to be encouraged, you, the Commission, to pursue changes at NEPOOL, and quite frankly, we think you have enough to do to try to get into that ball game so we also support Option B.

DR. RAAB: Any other stakeholders? Yes, Nubia?

MS. PEREZ: Very quickly in terms of having Narragansett be the verifier, Narragansett doesn't really, I don't think, want to do this. It doesn't -- it shouldn't be compelled and it shouldn't be forced. What this is is, as Mr. Grace said, it's a barrier to the free market. There's no reason why the aggregators wouldn't choose who their verifier should be. Quite frankly, it would be expensive and this cost would go to the ratepayers themselves.

In terms of Option A and Option B, the change, it really isn't that big of a deal. What

it is, it's a matter of tweaking the log-in process. The verifier would go there and she or he would go in and change the one module that has to do with entering the generation data and it would have a consistent reporting procedure all across the board and would add integrity to the entire process.

MR. NAULT: Your comment regarding the cost of Narragansett being the verifier, why is it your position that it would be more expensive to have Narragansett do the function?

MS. PEREZ: Well, these -- I would assume that a lot of these behind the meters are not close to the grid so that would mean they would have to go out there and see these meters and there's no reason why Narragansett should have to do this. If there's companies that already exist, I believe -- where is this company located?

MR. STEPHENS: In Massachusetts.

MS. PEREZ: In Massachusetts there's companies that already have the capabilities of doing this and the process is already implemented.

MR. GRACE: If I could reiterate another aspect here, as I mentioned, the fund has already invested in data collection communications equipment for a number of these installations, so the data is already being metered, already being communicated to a centralized collection point. To inject an additional verifier, you need to put an additional meter in there and send a meter reader out. So it's basically duplicating costs, so that's the other reason that the cost may be higher.

COMMISSIONER HOLBROOK: What kind of activity is involved here? How many meters would be subject to being read and with what frequency?

MR. STEPHENS: Right now if this were to be put in place tomorrow, it would be on the order of frankly 50 meters, something like that that I'm aware of. Obviously, the hope is that it's going to grow quickly from there. So I wouldn't look to today's numbers to be an indication of where we want to be. I would -- getting back to the question of, you know, what the expense -- why would it be more expensive to

have National Grid do the meter reading, the reason is -- well, put it this way. If National Grid could do it less expensively, then maybe we should look back at the T&D costs they're charging us, because if you look at the customer charges that presumably cover things like meter reading, they're substantially higher than what these new technologies have been able to do. These new companies, you know, quickly adopt new technologies a little more nimbly than a large distribution company understandably and just have the technology and ability to read meters very efficiently, and in fact, they do it -- your other question about how frequently, I think to meet the GIS rules it would only have to be done quarterly not monthly. But these new technologies are so efficient that they get instantaneous data.

Just as a matter of note, this is basically what we're describing with this independent verifier actually reading the meters is what Connecticut already adopted, as I understand it, VAEIS, as the company that was mentioned earlier has been approved as one of

these third party meter readers by the Connecticut PUC, and so I think this is really clearly a way to go in terms of allowing the marketplace to identify the most cost effective solution to this problem.

DR. RAAB: Tom Robinson from National Grid.

MR. ROBINSON: Yes. I just wanted to say that we aren't opposed to reading meters. We do that for a living. The customer charge that Erich mentioned has nothing to do with our costs. We have to do a separate cost study. I think the big impediment to this process has been that NEPOOL rule. Today people are self certifying and that the Energy Office is supporting meter reading and data collection and so forth so the process is working today. I think that's incorporated in the proposed rule. It's whether we have to change the, or whether we wish or have the ability to change the NEPOOL rule to have some data entry system that goes straight from Narragansett or from the Energy Office to the GIS system. That is the issue here. Reading meters is a relatively small component of that problem

and I think it can be addressed in any number of ways. We're neither opposed to reading meters nor do we require that we read all the meters. I think it's a secondary problem associated with this issue.

DR. RAAB: Nubia?

MS. PEREZ: If I could just add one more issue in terms of Option A. What this would allow is the generation data to be entered before the certificates are created, therefore, there wouldn't be a true up process that would be necessary at the end of the trading period.

DR. RAAB: Any other questions on this dispute?

MR. FRIAS: On the Option A, Mr. Stephens, I've been hearing more and more that this is going to require NEPOOL changes. Is that your position? Do you agree with that assess?

MR. STEPHENS: Yes, but simple technology changes. I don't think it would require any, you know, change in policy. It wouldn't require any change even to the database itself. It's really just frankly a question of a little web mastering to allow this change to go

into place, and as I understand it, the GIS was meant to serve the rule makers of the various states, so I think it's quite proper and appropriate permission to ask this simple change to be made.

MR. FRIAS: If we were -- if the Commission were to approve Option A and NEPOOL tells us to go scram, what are we going to do?

MR. STEPHENS: Option B.

MR. FRIAS: Basically what you're saying is adopt Option A, go ask NEPOOL, we have a couple issues we're going to ask them to please change and if they didn't, then we'll fall back to Option B is your position right now.

DR. RAAB: I think that's the position of that whole group and that's what is stated in the whole document.

MS. PEREZ: Also keep in mind that it wouldn't be implemented until 2007 so it would be a while.

MR. GRACE: If I could just comment on the process for changing the GIS rules at NEPOOL. I represented another client on the GIS working group and have been involved in a number of other

rule changes since the original adoption of the GIS rules. The GIS rules were envisioned to be something that would be a living document and that would be changing regularly in response to changes in market conditions as well as changes in state policy and statute. The GIS has a contract with its vendor and as a matter of its own process envisioned this and every six months has established a process for considering and incorporating changes of this nature as a matter of its ongoing business, so it's not a stretch at all to propose this, have it be considered within the due course of operating the GIS and have it either adopted or not. It's rather straightforward.

MR. FRIAS: Just a question to Narragansett Electric about "the costs of checking out 50 meters". Does Narragansett Electric check those meters at all right now, those types of meters, that type situation?

MR. ROBINSON: I don't believe we do. There may be some circumstances under the standard generation rate where we meter outside generation, but I'd have to go back and check to

see. But outside meter readings we meter and don't. I'm not familiar with the program that Mr. Short mentioned or the charges. We can do that, provide it as a record request.

MR. FRIAS: Actually, it's not necessary to be a record request at this point. How often would this -- this may be a question of Mr. Short or somebody in the group. How often would Narragansett Electric be required to go check the meters? How often? A month?

MR. SHORT: The load response program, which is what the tariff would be modeled on, is essentially telemetered, so it's read effectively instantaneously.

MR. FRIAS: Okay.

DR. RAAB: Moving on to section 7 which is demonstration of compliance, there were no disagreements, lingering disagreements in this section but some questions have been raised that wanted explanations and some of the language which may not have complete sentences, so Bob Grace was going to step through a couple of the questions that have been raised and clarify that.

MR. GRACE: This whole section,

demonstration of compliance in general was adopted from the Massachusetts rule; the process is nearly identical. There was no need to create a new process. The process working in Massachusetts is working well and effectively and really encompasses just about every circumstance envisioned in the statute here, so much of the language here is as it is because we started with the Massachusetts language.

The specific questions that were raised on Section 7.3, and please explain how this section would work moving through each sentence, this is the section that applies to how alternative compliance payments would be addressed in the process of demonstrating compliance. Basically, what an obligated entity would do at the end of -- at the end of a year if that entity's load was 1,000 megawatt hours in that year and that RPS in that year was three percent, it would need to demonstrate 30 certificates. If it had 27 certificates, and therefore was -- were three certificates short, it would need to make a payment of the alternative compliance payment to the Economic

Development Corporation's renewable energy development fund of three times the alternative compliance payment. This envisions that after making such a payment that obligated entity would have a receipt documenting that and as a matter of demonstrating compliance that party could show if it needed 30 certificates, it had 27 GIS certificates documented by NEPOOL GIS documentation and that the residual, the three megawatt hours they documented that they had paid their alternative compliance payment.

The tail portion of this section that describes where an obligated entity enters into a prospective agreement with the Rhode Island Economic Development Corporation to accept alternative compliance payments pursuant to the statute, Section 39-26-7(b), et cetera, that is referring to a mechanism that was included in the statute that allowed for obligated entities to enter into longer term prospective contracts with the EDC to pay alternative compliance payments ahead of time. So that would be a little different mechanism whereby an obligated entity might almost seek to subcontract its compliance

to the Economic Development Corporation, and in exchange for that when -- if the Economic Development Corporation did turn around and procure certificates, those certificates would effectively be assigned back to the obligated entity to make the books balance. I'd ask Mr. Duffy or Mr. Dzykewicz whether I mischaracterized anything as they understand it.

MR. DUFFY: I think that's accurate.

MR. DZYKEWICZ: I think that's accurate.

MR. GRACE: The next question that was posed was Section 7.4, Subparagraph Roman numeral iii. The first part is not a sentence. It looks like the word allow was omitted from the beginning of the sentence, so it would read, "Allow renewable energy generated during Calendar Year 2006," et cetera.

The next question that was posed, Section 7.9, Roman numeral ii, was how would this calculation work. This dictates that the quantity of credits specified in megawatt hours that can be applied to the obligations of an obligated entity would be determined by

calculating the ratio of the total payment to the Economic Development Corporation's renewable energy development fund divided by the payment rate. Basically, this is to return to my earlier example. If the alternative compliance payment in a given year was $50 per megawatt hour and the obligated entity was three megawatt hours short, by making a payment of $150 to the renewable energy development fund, it would fulfill its obligations, so dividing the 150 by the 50 equals three megawatt hours. That's the calculation envisioned here.

The last question that had been raised in Section 7.10, Subparagraph 2, what is confidential. The sentence that this is referring to, the Commission shall keep product information confidential to the extent permitted by law, I guess I have to leave this to obligated entities perhaps to argue what they may consider confidential. My understanding is that obligated entities may consider the volumes of sales under given products to be commercially sensitive information and I would envision at the time of filing that pursuant to existing law and

regulations governing treatment of confidential information, an obligated entity at that time may seek to protect information under those rules and the Commission would have to respond to that and decide whether it was something -- so I think this would be ad hoc. If requested, you'd have to make a ruling on whether that information would be treated confidentially.

MR. HARTLEY: And if I may add, when this was being discussed and I was representing the Commission's point of view, I stated that this was a well established way of operating for the Commission. If someone requested something be kept confidential, the Commission knows just what to do and just how to go about it. Nothing fancy there.

THE CHAIRMAN: Well said.

MR. GRACE: I believe those were all the questions posed ahead of time. If there are any further questions that I can answer as primary author of this section, I'd be happy to.

DR. RAAB: Otherwise, we can move to the fun and games in Section 8.

THE CHAIRMAN: At this point take -- as

a matter of fact, take lunch now. That's an even better idea. Take an hour break.

(LUNCHEON RECESS)

AFTERNOON SESSION

AUGUST 31, 2005

1:15 P.M.

THE CHAIRMAN: Back on the record please. Where were we?

DR. RAAB: We're going to go to Section 8 now which is on contract standards and procurement plans, and I just wanted to I guess say some opening comments here and then turn it over to the stakeholders to describe a little bit about what the disagreement is, but I think the primary point that I want to make is that the group is pretty much wholly in agreement as to what's in Section 8 right now as a process to move forward. The disagreement comes on how some of the information that comes through the process is handled, specifically whether the electric distribution companies should be looking at long-term contracting for one issue, and another issue, which is a dissent from TEC-RI and Silent Sherpa ECPS, is that what's here in Section 8 should also be applied to the renewable energy development fund administered by the EDC.

So those are the two issues. Again,

the disagreement is less on what's in here as to a couple of issues that are important issues, but are around the edges of what's here. So I'm going to -- what I'm going to do is have National Grid just work through -- walk through how the contracting and procurement process would work, and then we'll let some of the dissenting parties talk about the issues that I just mentioned.

COMMISSIONER HOLBROOK: Dr. Raab, before you do that, and you may be proposing to go into what my question will be, but I see three parts to what we're talking about this morning. One is the problem which is to get more renewable sources of energy into the system by the year 2020, the second piece would be the concept of the solution, which is the program, which is market driven, and then thirdly is what we're discussing this morning which is the rules to the concept of the solution. Okay?

So I wonder if I could ask you before we go into Section 8 to take five, six, ten minutes, whatever, and just give an overview of the program, okay? How it will work, how these certificates will be issued, what the value of

them, you know, will be based on market dynamics and whatnot. That would be beneficial to me. I'd like to have it in the record and just pretend that you're meeting an old friend down the street and you're saying, "This is what I've been doing for the last two months," okay, and try to let that person, me and others, understand from the horse's mouth conceptually an overview of the program.

DR. RAAB: Of the program meaning how the regulations or how the market would work essentially?

COMMISSIONER HOLBROOK: Yes.

DR. RAAB: I guess I would say as the mediator this is probably not the best horse to hear it from. I'm obviously dealing with the details of getting everybody to agree. In terms of talking about maybe how the market's going to work, I would probably ask one or two of the stakeholders to do that if you don't mind.

COMMISSIONER HOLBROOK: That's fine.

DR. RAAB: I think you'd get a better answer and I think I would let Bob, maybe, if you don't mind taking a first shot at it, and maybe a

few others. Bob has done a lot of work in other states and a lot of work, so if you don't mind, Bob.

MR. GRACE: Did it again. I guess just to start from obviously we have the purpose of RPS is to meet certain objectives and in this case the objectives are delineated in the statute, but the bottom line is to increase the proportion of renewables contributing to supply by setting a target and then letting the market work efficiently to find a least cost way of doing so. So by setting targets that increase over time and apply them the obligated entities, there is defined demand or renewable certificates over time.

With that demand obligated entities have to either shop or pay the alternative compliance payment which serves a couple of different purposes. It serves to be in effect a penalty for not complying, but really, there's no penalty nature to it if you do pay it, but it also serves as a price cap, so that if the dynamics of supply and demand were such that the cost of buying certificates was more than that,

you can simply pay the alternative compliance payment and cap the cost to consumers of compliance. So within that context with obligated entities having the incentive to shop and comply that at the same time creates the incentive for investments in new renewable that's meant to be made by investment in generation and ultimately, like any other market, the price at any time, the short-term market price of an eligible generation power certificate is going to fluctuate with supply and demand.

In Massachusetts we've seen this play out where the rules were put in place with very little lead time before the standard was actually in effect, and therefore, the market's been playing catch-up. Demand has been ahead of supply and you've seen the initial prices be high, and as a result of that you're seeing quite a bit of development in the region and more and more renewable projects are coming on-line and forward prices are starting to drop accordingly.

That really foreshadows the nature of how the market will work because renewable generation is -- tends to be very capital

intensive. The general way that renewables have been built in this country has been when there's been a long-term contract with a creditworthy buyer that justified the investment of capital in that project, and therefore, has allowed that capital to be amortized over time, allowed debt financing that was paid out over time much like a mortgage and thereby makes the per kilowatt hour cost of renewables reasonable or brings it into the range of other alternatives.

In this environment, in a competitive environment, the mechanism is that the buyers aren't the same buyers that you may have in other parts of the country that have not gone through utility restructuring, you don't have actual fully integrated utilities with a stable load that are the only market you have, you know, anything ranging from competitive suppliers, non-regulated power producers come into the market, you have providers of last resort, standard offer, and load shifting over time, so you have a more complex environment in which to get projects financed and which to find long-term contracts to do so. At least for the time being

there's almost no experience in this country with projects being built without long-term contracts or substantial subsidy coming from other places.

So that's a little bit of the backdrop to the conversation we've been having about long-term contracting and some of the reasons why the statute had some language pertaining to procurement plans and long-term contracting.

Foreshadowing that would be an issue here how obligated entities will go about procuring and how projects will get financed with something worthy of the Commission's attention. Generally speaking, the cost of renewable energy certificates if there are long-term contracts will move in accordance with a couple of different drivers. Obviously, there's supply and demand much like the energy markets and capacity markets at NEPOOL. They'll tend to clear based on what the marginal resource is or the next resource in. So if the last resource available happens to be very expensive, then the prices may rise. Rising prices create incentives for new entry to come in that can do it for a lower cost.

The other dynamic here, since the whole

idea behind an RPS is to assure a premium, if necessary, above the revenues that a generator would get through the conventional electricity markets, the energy and capacity markets which they, of course, participate in and get energy from. The renewable energy certificate effectively represents a premium or additional revenue stream. If electric prices go up, as they have been, presumably, all else being equal, the renewable energy certificate prices needed to attract investment would come down and vice versa.

So under this market structure there's something of a hedge built in for customers. If electricity prices rise, presumably the cost of compliance is going to drop in proportion.

COMMISSIONER HOLBROOK: Why is that?

MR. GRACE: Let's take an example, a new renewable generator, if they're able to get a long-term contract and they effectively needed, let's say, $0.08 a kilowatt hour in revenues from all the different sources, energy, capacity and renewable energy certificates, over the course of 10 or 15 years in order -- they have this

guaranteed revenue, they'd be able to attract investment to the plant. Now, if will you, the electricity markets if they could get a higher proportion of that, let's say, recently we were seeing electric prices that are getting in the range $.06, $0.07, even higher on a short-term basis recently, that would decrease the amount out of what they need that they'd have to find in renewable energy credit prices, so if there is a competitive market and you've got generators competing against each other for that premium, and that's what a renewable portfolio standard does, it's going to -- the obligated entity is going to buy it from wherever it's cheapest, so given that competitive pressure, the competitive pressure is going to keep the -- that clearing price on all in basis, that $0.08 will be driven from the competitive pressure and the energy market would provide a larger proportion of it in the event that energy prices are increasing, and therefore, you would expect a lower price on renewable energy credits.

COMMISSIONER HOLBROOK: What are the dynamics of the pricing, the clearing of the

value of the certificates? How does that work? How does that mechanism work?

MR. GRACE: The market energy certificates is effectively an annual market. The certificates are created quarterly at the NEPOOL GIS but the obligation is annual, and within a given year an obligated entity would have the entire year or each of four quarters in which to shop for its renewable energy certificates, so basically the market is annual. If there's demand and supply in a certain year, if there are sufficient certificates available, the market would clear at the marginal cost.

Now, you really have much like capacity energy in the other markets that we're experiencing, electricity you'll have short-term and long-term transactions going on. The presence of banking will change. What I'm about to describe a little bit -- let me come back to how that would affect it. In the absence of banking you'd have a market that looked a lot like the capacity market at NEPOOL in that you have an excess market, prices are going to tend to crash toward zero. If you have a shortage,

they're going to tend to increase to the cost of entry or higher. So you'll have almost a buyer's market where short-term prices will either be high or low and because that creates an unstable environment for -- an unstable and risky environment for both buyers and sellers, there'll be incentives for both parties to enter into a contract of some duration to mitigate that risk and create something of a longer term forward price that represents the cost of renewables. The presence of banking will change that a little bit. If prices are expected to crash or there's ample supply, obligated entities can buy more when the prices are low and save them for later and that will tend to keep the prices from going to zero, and of course, you have the alternative compliance payments to constrain the prices on the high side. So I expect over time you'll see spot prices that will fluctuate between something above zero, given the incentive to -- for obligated entities to shop when prices are low and when the expectation is that the market may be short, those short-term prices will tend towards the alternative compliance mechanism, but

because those are somewhat unstable prices, you'll definitely have obligated entities that will be operating on a longer term basis. You'll see forward prices that will tend to be more along the lines of what things cost, and you're seeing that today. There are forward markets developing for Massachusetts and Connecticut certificates and there are prices that are more representative of the fundamentals of the market where supply and demand cross and what it actually costs for renewable.

COMMISSIONER HOLBROOK: Who will the participants in the market be?

MR. GRACE: Generally speaking, you will have three classes of market participants. You'll have generators who are creating the certificates, you'll have the load serving entities or the obligated entities who have the obligation and then you'll have parties that are -- they may have trader accounts, but ultimately, you'll have parties that are taking middleman positions.

COMMISSIONER HOLBROOK: Will speculators come into the market?

MR. GRACE: These middlemen will include speculators. They may be in the wholesale market taking the position one way or the other or seeing opportunities for their business interests to be met.

COMMISSIONER HOLBROOK: I'm hardly an expert on how the markets work, the financial futures markets work and whatnot with respect to natural gas, but I've read and I've heard that maybe a third of the players in the futures market that has an effect on prices that gas companies pay and utilities pay for natural gas make up the market, a third of the players are speculators with no intention of taking delivery and whatnot, it's a gamble, okay, that their investment will appreciate in value. Should the Commission have any concern with respect to an undue presence of speculators coming into the market which really means that at the end of the day ratepayers are going to have to pick up the game, the roll of the dice that speculators are causing in that market or am I way off base on that?

MR. GRACE: I think actually the

presence of speculators, economic theory and I think the way other markets work would suggest that it's a reason for confidence because those speculators coming in and taking a position tend to bring the market toward some type of equilibrium and speculators ultimately need to live off their risk as well. Very few parties take purely speculative risks, and so most of those speculators will look to come in and maybe take a position where they can make some money, but they're going to want to live off that position and match a service with a sale and those activities tend to actually drive the incentive market prices and visible market prices. So I think we could have some confidence that that activity actually rationalizes the market and tends to bring market prices towards what it would cost to build new generation. If those prices differed from what it cost to make generation, then somebody out there would be either making or losing a lot of money.

COMMISSIONER HOLBROOK: To the extent the certificates are valued at a price that would reimburse the generators for the investment that

they've made in -- to switch into more efficient fuels, more renewable fuels, I don't think anybody would have a problem with that, but to the extent that prices became inflated to reward speculators in the market, I understand that's the market dynamic, but it's a premium involved in the equation and if it becomes a large amount of money, then it's above and beyond the brick and mortar of the physical cost of the conversion to renewable fuels and I'm just curious about the impact of that, the magnitude, the scope of it, okay, because I suspect if you look at, and I heard on the radio at lunchtime that oil went to over $72 a barrel and I don't think they're paying $72 a barrel at the wellhead, so speculators are driving the market. It's the boondoggle, it's, you know, the Oklahoma land rush and it's taking an awful lot of money to be put into the market, some people make money, some people just bleed because of it, and this is one of the concerns I have about the program. I just want to understand it. Okay? So that five years from now, three years from now people are not surprised when the cost of the program is

identified and creeps into the rates and they begin to realize that X percentage of it, an inordinate percentage of it, okay, is just, you know, an amount of money to feed the system which is capped and risk taking and reward.

MR. GRACE: Those are all valid concerns and I think the way renewable portfolio standards have been developed really takes into account a lot of those concerns. The Rhode Island RES has had the benefit of being able to come after a number of other renewable portfolio standards and identify best practices and really avoid some of the concerns that have been raised or learn how to do it right from the experiences of others.

Part of that is there are several safety valves that are built into the statute. One is the ability to bank, so that serves entities that are concerned about the possibility of future high prices can effectively insulate themselves against this by buying some excess and carry that forward conceptually as some insurance against high prices. In fact, I commend National Grid in its proposed procurement plan here that

they would be looking to get prices early and consider early compliance to do just that.

The second is the alternative compliance payment which has been set to be roughly twice what people expect the cost of entry to be, so that really serves two purposes. It allows the market to set price signals so if the prices rise, that signals that there's a need and will draw people into investing and creating more renewables with the confidence that it costs less than that to build more renewables; generally renewable plants are smaller and more modular and can come on-line more quickly than conventional power plants and as well when you have the ability to have co-filings of biomass and fossil fuel plants or the ability to expand the output of despicable biomass plants, there's some short-term ability to increase supply quickly in response to that demand signal.

So there is the ability for the market to respond fairly quickly to those price signals and have prices come back down as additional supply is brought on, but in the event that the market diverges, that supply can't keep up with

demand, which obviously is a very important concern for ratepayers, the third safety valve comes into play and that's the ability for the Commission at a couple specific points in time to step back, take a look at how supply and demand have been developing and the degree to which there's additional development in the pipeline, to respond to that and I assume if the Commission saw supply and demand diverge from that, it would take its opportunity to slow down the rate of increase and let supply catch up. So the combination of those mechanisms were rather explicitly designed to address the concern that you raised.

As well we have the ability for generation outside of New England to come in by various import transactions which are not easy; they come at a cost. A generator outside of New England would have to transmit its energy into New England real time and that is not an easy or cost-free process, but it does allow that more resource rich areas can also provide resources as something of a safety valve and once we have more and more projects being developed in the region,

as most of the states now in the Northeast have renewable portfolio standards, you'll see more and more of an ability to react quickly to price signals.

Just as an example, right now there's a 100 megawatt wind plant being built in Upstate New York in response to New York's portfolio standards. That project is permanent for something like three or 350 megawatts and could very easily add a turbines and something like that can be done in a couple of months in response to demand and that capability and the infrastructure should hopefully find the ability to keep prices from being sustained at an unreasonably high level.

COMMISSIONER HOLBROOK: So the cycle I guess is that the more the system shifts to equipment that will use renewable energy sources, the lower the value of the certificates would be?

MR. GRACE: Yes.

COMMISSIONER HOLBROOK: So the market is constantly looking for balance.

MR. GRACE: The market is constantly looking for balance in supply and demand. It

shouldn't function dramatically different from this, and as an analyst of these markets I've been involved in probably as many attempts to forecast supply and demand and price as anybody. I hear from people in the market many concerns about high prices and low prices. There's a lot of development activity out there and a lot of generators are concerned that prices are going to crash as customers are concerned that prices are going to increase, so you know, it's rather non-scientific sampling admittedly, but I think there's at least a reason to believe that this may end up not being particularly costly for Rhode Island customers as our worst fears may be.

COMMISSIONER HOLBROOK: Just one final comment. I would understand that this program, the nature of this program that's on the table right now is proven. I mean, it's been utilized in the past, it has a track record and it does work.

MR. GRACE: Yes. There's quite -- the track record isn't very long. It's really renewable portfolio standards and mandates like it really came along with the advent of

restructuring as a way of replacing some of the public benefit programs that had been in place previously. But we now have the experience in quite a number of states ranging from Texas which has been extremely successful and a number of other states, Wisconsin, New Jersey to name a few that have been so successful that they are going to increase their targets because they set them ahead of time and they said let's do more.

The rules here for the most part take advantage of the best of the design features of programs elsewhere so I have a lot of confidence that this is a reasonable set of tools to achieve the objectives and keep things from derailing in a way that ultimately you folks up there on the podium are going to have to defend it.

COMMISSIONER HOLBROOK: Okay. Thanks.

DR. RAAB: I'll turn it over to you guys in one second. So we wanted to talk about Section 8 following Bob's excellent broader background in which the stakeholders I think developed a fairly unique process to try and identify both sellers of renewable energy credits over a longer time period as well as buyers and

then we'll talk about where the difference of opinion is which really goes to the role of the electric company in terms of signing long-term contracts. I'm going to turn it over to John and Tom to just run through how Section 8 would work in terms of contracting and procurement and then we'll open it up to where the disagreements were.

MR. ROBINSON: I was just going to make a few more comments on the market dynamics I think from the perspective of a buyer, and before I turn it over to John to tell you how we've tried to deal with those in the contracts and the rules and the regulations, but there are a couple of differences between the REC market and the regular market.

First, we have a legal obligation to buy certainly while we're serving the load, so one of our concerns has been to match our obligation to buy the REC certificates with the load obligations that we have, and I think actually the parties have come to a very creative solution to that to allow our obligations to fall off as our purchase obligations fall off to be picked up by other load serving entities in the

market.

There's another just follow-on to a comment from Bob, the way I look at this is there's two scenarios associated with the renewable certificates. One is that the program totally fails. If the program totally fails, that's why we built in the alternative compliance payment. We have a legally mandated obligation to buy and if there's nothing to buy, the price would theoretically go to infinity unless we had a cap on it. So the cap is the alternative compliance payment. It was negotiated as part of a very similar one which was negotiated in Massachusetts as part of expanding their program to include distribution companies who just weren't willing to sign up to an unlimited checkbook on that.

So we know what that scenario is and the question came up this morning well, what happens to the direct costs if nobody comes to the party and we just keep paying Andy and the Economic Development Commission, the alternative compliance payment throughout the remainder of the period. It's about $100 million of direct

costs, not including energy savings per year as we move out into time and the percentages get higher.

COMMISSIONER HOLBROOK: If I could stop you there for just a second, if that is the scenario and that does happen where the market doesn't provide you with the renewable source and you have to pay this premium into the fund, then what happens to that money and how does it solve the problem?

MR. ROBINSON: Well, Andy gets it, so he's a major now developer of these projects. He goes off and executes the contract, uses the fund much like the NTC in Massachusetts is trying to do now, uses the fund to help develop projects and then releases the RECs from those projects back into the market which hopefully is a loop that flows back that provides adequate supply that reduces the overall payment below the alternative compliance payment. So we've thought through some of that and that's -- I guess that's a failure scenario.

The direct success scenario case one, and as Bob indicated, the short run marginal cost

of generating a REC at the same time you're generating a kilowatt hour from a renewable, many renewable projects is very close to zero, so the market could theoretically crash to a very low point when there is an excess of supply of renewable energy above the legally mandated purchase, and quite frankly, the load serving entities have to comply with the law. We've created a green up program that gives suppliers an incentive to green up their product and do better than comply with the law, help to market that, but there's not -- and so some of the demand from that may well help to keep the price up when the cost falls down, but it's almost like two pegs on the speedometer, it's either way up to the alternative compliance payment or potentially very close to zero, and of course, that's a big concern for the suppliers as well. But it's a big concern for us when we look out into the future and we don't really have the ongoing operating market today. We're basically up very close in New England, we're short of the legally mandated supplies from Massachusetts and Connecticut. When Rhode Island adds onto that

we're not quite sure.

The DOER in Massachusetts has done an analysis that many of the people around this table disagree with, but nevertheless, they're the agency who is responsible for administering the program there. They expect that supply will exceed the legally mandated purchases in New England, including Connecticut, Rhode Island and Massachusetts in 2008 and thereafter. So it's all a matter of where you think the cross-over point is going to be, but the issue with long-term contracts before we have the market really operating is we don't have any basis really to forecast where that is going to be except it might be very low or it might be $0.05 a kilowatt hour. If we strike a balance at $0.03 a kilowatt hour, say, we'll look good for a couple of years maybe, but if the supply turns, then our contract payment is going to be much higher than the underlying market price and we've been through that before and that is ultimately called -- contributes to stranded costs and above market payments and we look a little bit like simpletons which we did before restructuring and

we're still paying for some of those above-market contracts today in our stranded costs.

So that's the concern is we really don't have a very good forecast of what the market price is going to be. I think it's a concern for the developers. It's certainly a concern for us as a contractor or as a potential buyer. So the solution in the regulations that we worked out was to say okay, Narragansett, in the near term when we know we're going to be short we'll in fact go out for bid but we'll bid out for a longer period and we'll make those longer periods -- and we'll have the right to commit while we're still providing the standard offer service and then provide the market with the opportunity to contract for the remainder of the period and that's the solution and the compromise that's reflected in the rules.

Now, some people still aren't quite happy with that, but I think it's -- it may be helpful just to hand out the DOE -- the Massachusetts DOER's forecast. It came from Jonathan's excellent roundtable that he carries on every month and there's also a report on the

DOER's website, but it gives you an indication of at least their view of the supply and demand in New England, and it's a power point chart so it's fairly easy to read. So I'll pass those around if I might.

DR. RAAB: So I think John was going to just walk through a little bit the nuts and bolts on how Section 8 works and then I'll turn it over to Dennis for long-term contracting from many person's perspectives.

MR. WARSHAW: John Warshaw from Narragansett Electric and National Grid Company. What the group put together was a set of standards that are flexible, that allow the Commission to set the requirements of the renewable energy standard both now and going into the future to be able to factor in future market developments and future Commission issues and Commission policy. So that's basically what the group came up with. We developed a set of contract standards that are suggested, we came up with an annual compliance plan and the annual compliance plan is where the obligated entities, Narragansett Electric is one of them, would

propose how they would go forward to procure renewable energy to meet the renewable energy standard and this would be, you know, as part of an open proceeding where the Commission could review the plan, make modification, order modifications to the plan, allow interested parties to participate to be able to provide their input and we felt that this was a good place to be able to allow input for changing market conditions.

What we also put in place is a way to address Narragansett Electric's specific standard offer obligation. We currently have contracts that were signed back in -- at the time of -- in the '70s. These contracts do not provide any renewable energy standard within them, they're just strictly providing the energy that's sold to customers on standard offer. What we put together was a way of allowing National Grid and other entities to go out and meet the standard offer obligation over the remaining period which is through 2009 and at the same time request proposals from suppliers for meeting -- for selling RECs past 2009. We are -- also as part

of the plan we would be looking to get potential buyers who would have expressed an interest in buying RECs over the longer term to review these proposals and we would be almost like a matchmaker. We would be able to introduce A to B and then we would step outside of that for that purchase of that, that would be after the standard offer period. We also would be looking to share that information with the EDC, with the Division and with the State Energy Office. And basically what we look at is having Narragansett's obligation go out through 2009 when the standard offer period ends, and as far as meeting the load that's unknown which is last resort service and whatever obligation the obligated entities have after -- Narragansett Electric would have after 2009 would be met with, again, through the standard procurement plan, the annual procurement plan filing and process.

DR. RAAB: Okay. So I think we were going to turn it over to Dennis who wanted to talk about the role of the electric company during the out period.

MR. DUFFY: Sure. Well, I think it's

fair to say what's been proposed is a fairly practical RFP type process to consider bids, but what it doesn't really do is address or resolve the great issue of the day. Probably the most important issue in the proceeding is that whether the utilities have an exclusively short-term purchase obligation or a long-term obligation. And that really goes to the heart of the whole case and I think as pointed out in the materials, I think a majority of the parties in the proceeding agree with the position that the statutory intentions would be better served if the utilities were required to also consider longer term purchases of a term that would be more in line with the financing periods required to get new renewable projects financed and actually built.

Now, really maybe the key place to look at this is back to the wording of the statute. What the statute asked the Commission to do is to set up rules which include standards for contracts and procurement plans for renewable energy resources to achieve the purpose of the chapter. Again, I think we can go back probably

to the beginning and ask ourselves again exactly what are the purposes of the chapter and do long-term or short-term purchases better fit that purpose. And in that regard I think it's very clear what the legislature said. When they stated the purposes of the act, it's Section 3, they stated three purposes, enhancing environmental quality, first, secondly, stabilizing long-term energy prices; not minimizing short-term REC prices, it's long-term stabilization is the statutory purpose. And our position is at the most basic level exclusively short-term pricing and procurement will not meet a goal of long-term stabilization.

Now, the third purpose of the act is creating jobs in Rhode Island in the renewable energy sector, and again, we think that you're much more likely to meet that legislative goal if you put the type of procurement provisions in place which give the credits necessary for projects to get financed and built in Rhode Island or associated with Rhode Island where the jobs can happen.

So we think that when you look closely

at the statutory purposes, the proposal that's laid out in the report which really only takes us through 2009, basically by the time projects are up and running we're looking at a three-year window of a purchase obligation. Three years is not going to make a meaningful enhancement of anyone's credit profile if they need to get project financing done to get the types of projects built that the whole statute was intended to do.

Now, I also understand Grid's position, their position that the market may tend to crash to zero or it may go back up to 50 to the cap, it may tend to be one or the other and that's also why we think it's in the interest of all the parties rather than to risk it at $1 or $50, say if there's someplace in the middle where both parties could agree that a long-term, more stable price would be in everyone's interest and more consistent with the objectives of what the legislature was looking for.

I also feel very strongly that this is a legislative directive. It's not being done at the initiative of a motion of the local utility,

so I think when -- if and when this does go forward, make a long-term commitment pursuant to a legislative directive that their shareholders should not be placed to the risk of a hindsight review on that and I think the key to that may be getting pre-approval or Commission review of the commitments as and when they're made, but I do understand; I don't think the shareholders of a utility should be placed at risk.

I also think if we take a step back to where we are today, today the Algonquin delivered price of gas is over $13. The forward gas prices for New England -- forward gas prices for this heating season are posted over $12, that's at the hub; plan on another $2 to get it here. We're at a time of extreme energy volatility. One of the things that you can get when you do long-term contracts with renewable producers is the price hedge of a stable, long-term price perhaps for energy and RECs from a producer who doesn't take any risk in the fuel markets and if you look at the overall volatility that the consumers are facing, again, we really believe that the long-term contract with renewables that don't

include a fuel ladder can overall reduce the cost to consumers but certainly stabilize them over the long term.

DR. RAAB: I want to just turn it over, as you'll probably read in the first paragraph, there were sort of three groups when we come down to it at the end and I wanted to just give the Energy Office and PP&L to maybe distinguish their position from the others. Bob?

MR. GRACE: I would like to start by building onto something that Tom had just said. He had laid out a position where National Grid would find it imprudent to do something other than wait around for the market to crash or rather there was some risk by entering into contracts at a price that they were foregoing at a time when prices would crash to zero. Ultimately, there's no chance that you're going to have a market that could sustain itself over time or in any great volume at zero without somebody building projects, and to get those projects built you're going to need the contracts, the credits, the investment to get the projects built. It's kind of a chicken and egg

problem that we can't ignore. You only get to the short-term zero prices if there's been a lot of building which means somebody's actually been buying it and creating the incentive to invest.

The State Energy Office believes for a number of reasons that at least in the current market end requirement long-term contracts are very important to minimize the cost of renewables to customers. There's a lot of evidence that the cost of renewables, because they're so capital intensive, will come down the longer the contract is much like with a home mortgage. Your annual payments are going to be cheaper with a 30 than a 10-year mortgage. Your renewable energy prices, all else equal, would be less with a 15 or 10-year contract than with a one or five-year contract for the same reasons.

The State Energy Office also has a statutory obligation in the RES statute to coordinate with the PUC and with Economic Development Corporation to minimize the cost and maximize the impact of the combined system benefit charge that the Energy Office is responsible for as administrator of the renewable

energy fund and the RES, and for that reason that really leads to framing the position here. The Energy Office is very much in favor of long-term contracts and in the face of National Grid's position and taking that position and their concerns over how long their obligations are going to go forward, we participated in the negotiation of this settlement language which I think achieved a number of particular benefits.

It does lead to making both short and long-term prices available for analysis and ultimate presentation on and justification before the Commission and it's our belief that those long-term prices are going to or the prices associated with long-term commitments will prove to be far more attractive over the course of this process than the short-term prices, and to the extent that the Commission agrees with National Grid's perspective on how long they should be contracting for, at least to provide us with the opportunity to come together, the short-term buyer and long-term buyer and to long-term prices. It gets around to what today is a market failure in other states, Massachusetts in

particular. Utilities, National Grid and others have been buying short term, developers of generation have been looking for those long-term contracts. The mechanism by which the primary buyers that are serving the vast majority of load are buying effectively shut or divide the market in a way that's very difficult for generators. A generator is going to be going around looking for somebody to sign a contract. The person who buys small load is not going to be signing those contracts, they're looking for somebody else to do it. If they're able to find somebody who might be interested in that contract for the longer term those are almost guaranteed to be shut out of the short-term market because the utilities are buying by RFP on a short-term basis and those buyers will change every six months or a year or two years and this proposal creates an opportunity to bring that together where ultimately the party that may be willing to enter into the longer term contracts can actually become part of the process and even step into a long-term contract and be able to sell to National Grid on a short-term basis enabling a

solution to what so far has been a market failure.

It also creates an opportunity for the State Energy Office as administrator of the renewable energy fund to fulfill its mission. The fund has its SEC checks, has as a result of this statute gone through its own strategic planning process and determined that it's important for it to spend a material amount of its funds towards minimizing the cost of the RES to ratepayers and assuring that generation will be available to meet the RES goals. So the program that's identified here creates an opportunity for the funds to come in in a process where there are prices proposed and parties interested in contracting and for the funds to potentially create incentives or make incentives available to the market to entice parties to enter into those long-term contracts, so it meets -- it creates an opportunity for the fund to fulfill its statutory goals.

DR. RAAB: Let me ask. You've heard the three positions, if you will, on this long-term contracting issue. I wonder if you had

any follow-up questions. We can also hear from other stakeholders on it if you'd like.

THE CHAIRMAN: Here's what troubles me. I think you may need a statutory amendment to permit you to have contracts that go past the end date. I mean, you're asking us to by rule permit a ten-year contract or past the expiration date in the statute itself, and I can understand why you're doing that, but it seems to me that that is something that should have been in the statue and gone through the General Assembly, and unless I have good reason otherwise, I would be reluctant to adopt any regulation which seems to me to be amending the statute.

MR. LUEKER: I don't believe it would require any amendment to the statute if they enter into long-term contracts for purchase of electricity now and all the rule would be doing would be actually, at least as we would propose it, would be to consider entering into long-term contracts to purchase electricity just like they are now.

THE CHAIRMAN: But that was pursuant to a statute which provides for the expiration of

these contracts in 2009. That's clear in the statute. You're asking us to adopt a rule which will permit the parties to engage in a contract which will expire ten years after the date upon which we are required to have renewable portfolio standards. That sounds to me like you're asking us to amend the statute.

MR. LUEKER: But they can enter into that kind of a contract right now for ten years if they wanted to purchase electricity over that period of time. It's just a question of who they're buying their electricity from.

MR. GRACE: Chairman Germani, it seems to me like perhaps we're confusing or overlaying two separate issues. Are you referring to the issue we talked about earlier where after 2019 we would be potentially placing the concept of indefinitely subject to a Commission order?

THE CHAIRMAN: Yes.

MR. GRACE: I believe that's a separate issue entirely. That really goes to how long the targets stay in place for. This issue that we're talking about in Section 8 is really fundamentally different and it goes to not the

targets themselves but how the obligated entities go about procuring to meet those targets.

THE CHAIRMAN: Let me just see if I understand this correctly. If the expiration date set in the statute is 2019 for the renewable standards, then why -- you are asking us to authorize you to enter into contracts which go past 2019, aren't you?

MR. GRACE: The expiration that National Grid is talking about here is 2009, the expiration of their standard offer obligations. So at this point --

THE CHAIRMAN: I can understand that. Maybe I'm asking a separate question. Earlier you talked in terms of permitting by the rules long-term contracts which I understood would go past 2019, am I correct?

MR. CHAIRMAN: Mr. Chairman, not necessarily. It would be fine if they did, but a contract through -- a contract through that date of 2019 would also be sufficiently long to give a very sound basis for project financing.

THE CHAIRMAN: Aren't you asking us to permit you to do contracts in the regulation,

authorizing contracts to 2029?

MR. DUFFY: I had not thought of that. I had not in my mind thought that we were looking for contracts going out beyond 2020. We'd certainly like it, but we had not envisioned that.

THE CHAIRMAN: Then it's not clear to me. Maybe I'm missing something here. It's not clear to me.

MR. C. EATON: This may help. The statute provides that it keeps running after 2019 unless you take action.

THE CHAIRMAN: Okay. Go.

MR. C. EATON: So at 2020 the standard stays the same and forever unless the Commission deems to do something else. So I would argue that it keeps going.

MR. DUFFY: I think it's also important to point out that the majority of the positions that most of the parties signed onto didn't specify exactly what would constitute long term. If it would go beyond 2020, I think there are people who would support that, but still a contract which would run from 2005 to 2019 would

also satisfy that majority position and would be a basis to do project financing.

THE CHAIRMAN: My concern is that we do not take action pursuant to a rule which can be successfully challenged in court.

MR. DUFFY: Understood.

DR. RAAB: Tom?

MR. ROBINSON: I just wanted to address a little bit of the statutory concerns that we had. First, as I indicated, what we're trying to do in this proposal is to match our renewable purchases with our power procurement obligations and for last resort service because we're going out with a new bid RFP every six months or so. We would presumably, and have in Massachusetts, for example, bundled in the RECs with the energy and allow the wholesale market to pick the most efficient project which represents the sum of the two. It's only the standard offer where we don't have the RECs covered because those are residual legacy contracts.

With regard, however, to the statute, there's nothing in that statute that requires Narragansett to execute a long-term contract. No

where does it say that. There's no where in the statute that requires the EDC to execute a long-term contract. They have authority, the EDC has authority to execute a long-term contract to use their alternative compliance payments, but they are not required to. It's a matter for discretion given what the market is. If the market is wildly successful, there's no reason for them to execute a long-term contract.

THE CHAIRMAN: Let me ask the question in a reverse way, and correct me if I'm wrong. You're not going to get competitive generation built effectively until you can get the financing from Wall Street and Wall Street is looking -- is looking for a long-term contract upon which to finance it. Am I wrong?

MR. ROBINSON: We've had discussions with many wholesale suppliers who are executing long-term contracts with renewable developers. They may not be quite as rich or generous as the long-term contracts we had in the old days, they face their own market pressures, but there are suppliers out today. I've heard them testify in a legislative proceeding in Massachusetts.

Constellation testified that they're signing long-term contracts and that the problem is with the renewable development today isn't the lack of long-term contracts, it's the inability to get permits and the inability to be able to actually build the projects to add the supplies much more than the long-term contracts.

What we should be doing I think both here and in the capacity and energy markets as well is let the markets work and what we have is we have a legally mandated purchase obligation which is already tilting half of the equation for the renewable energy suppliers, but at least we should allow the market to work to the extent that it can rather than have a legally mandated long-term contract. That's our view.

And in addition to that, our view is we shouldn't be buying RECs. We aren't supplying the load and we shouldn't be buying RECs above the market price in any event. That just doesn't -- that's not a sensible position for Narragansett to be in given the other complexion of legislation that requires us to exit the generating market, open our retail markets to

other suppliers and allow them to provide it more effectively. There's no reason why they shouldn't provide RECs more effectively just like they provide energy more effectively. That's why we're having a resistance to signing long-term contracts as Narragansett.

Now, what we are willing to do is cover our obligations through the rules and through the annual plans. To the extent we have obligations that extend beyond the standard offer, we'll still be an obligated entity. We'll still be filing a plan. It will be a REC plan but we also have an obligation to file a last resort plan with the Commission, and what we'll do is we'll tie them both together so that we're buying energy at the same time we're buying RECs and doing it all as economically as we can to get the RECs out in front of the energy is not the most efficient procurement pattern. And we do have an annual obligation under the statute to file for last resort service. We just think that those should be harmonized and that we shouldn't rush into long-term contracts, particularly since the Massachusetts Department of Energy Resources

should have adequate supplies without long-term contracts by distribution companies.

THE CHAIRMAN: Are you willing to bet your mortgage on that?

MR. ROBINSON: Luckily, I don't have to bet my mortgage on it, but I'll tell you what, as Dennis says, if it's $14 per mcf for gas and the energy market is trading at nine or $.10 a kilowatt hour for electricity, based on those high gas and oil prices, the renewable supplier will bid in zero because they want to be dispatched but they get the nine or $.10 from the electric markets and they need the REC a lot less today than they did a year ago.

THE CHAIRMAN: Is that supposed to make me feel comfortable? Is that the reason they don't need this is because the price is going to go up so high?

MR. ROBINSON: So in order to fairly evaluate the market, you have to look at energy prices and you have to bundle them together. Allowing us to procure energy, at the same time to procure RECs or consistently the way we procure RECs allows us to do the most efficient

procurement.

THE CHAIRMAN: The General Assembly has spoken. What the national should do is go back to nuclear power in abetter form. Look at coal gasification and that would be another way of dealing with the problem. And I'm not convinced that renewable is the -- you know, it's the latest brand of salvation. Theology changes everyday. Today it's renewable, tomorrow it's --

MR. ROBINSON: It was gas a couple years ago.

DR. RAAB: As the mediator, I just need to correct one thing for the record is that we haven't listed the parties here that support the first -- until the last minute was sort of more than the consensus proposal. Mr. Duffy has characterized his position as the majority which actually isn't true. The group was totally split on the first two depending on how you count the last position.

THE CHAIRMAN: There are separate opinions here?

DR. RAAB: Just how it's characterized in terms of supporting the approach in 8 without

requiring the utility to consider long-term contracting. There are also five parties supporting that, so the group is really split.

MR. ROBINSON: I tried to call Thomas Acquino over lunch and he didn't answer the phone.

MR. C. EATON: He just doesn't answer your calls, Tom.

MR. DUFFY: I had a few words with him. Mr. Chairman, if I may, I just want to respond to a couple of points. Our friend is correct that the statute doesn't mandate utilities to make long-term purchases, but what it does do is direct the Commission to adopt by regulation standards for contracts and procurements to achieve the purposes of this chapter. As I pointed out earlier, specifically, the purpose of the chapter is not short-term minimized price for RECs. It's long-term stabilization of energy costs. So I think when you look at what the legislature actually said, their objective is a long-term objective, not a short-term objective. And I understand also that the utility currently is going out for short-term purchases of energy

for different services, but again, it's been characterized that that's efficient and consistent with market.

Well, it's consistent with one market price which is the spot price, the short-term price. In any given day in any commodity there are many market prices. There are long term, medium and short and that's why we think it's absolutely consistent with market theory to go out and hedge positions by not being exclusively in any one market, be it long or short, especially when we see the great volatility in the markets today.

And finally, I also understand that there's an issue of possible customer migration, but that's not unique to Rhode Island, it's not unique to this company or even the electric industry. Gas companies deal with it everyday in the restructured environment, so do electric companies. That's not a unique issue and it's not a reason not to have people consider long-term commitments. Many other utilities very effectively have diversified their supply portfolios both for supply, pipeline,

transmission, commodity supply bought jeopardizing the robust nature of a restructured market. We can work around that.

THE CHAIRMAN: The robust nature of the restructured market?

MR. DUFFY: Yes. Robust competitive market will not be undercut by a portion of long-term contracts.

DR. RAAB: Let me just ask if the Commission has any other questions on this contracting issue. We have another issue in Section 8.

MS. WILSON-FRIAS: Jonathan, I do. On some of the areas where you -- where the group did not come to total consensus there was alternative language provided. It does not appear that there was alternative language provided on this issue. Was that something that you decided to leave out or was there never alternative language discussed?

DR. RAAB: Well, I think the language is basically embodied in the dissent here which is that the obligated entities should also be required to consider procurement of renewable

energy over longer periods of time.
MS. WILSON-FRIAS: I guess my question is where would that go in the existing document, under which part of 8?
DR. RAAB: It would probably go under the 8.5 in dealing with what we're calling the third time period.
MS. WILSON-FRIAS: Third time period.
MR. DUFFY: We were up against a very specific filing deadline, so if it would be helpful, we can draft some specific language and submit it, but we were under a lot of time pressure on this issue.
MS. WILSON-FRIAS: I'm not sure if that will be necessary. It might be one of those things that if the Commission does decide to go in that direction, that you'll have to address it in your written comments.
MR. LUEKER: It's also probably worth noting that we're asking that the utility company consider entering into long-term contracts, not that they be mandated to enter into long-term contracts.
MS. WILSON-FRIAS: That's what's

contained here or that's what the Division's position as contained in that first sentence?
MR. LUEKER: That's the Division's position and several of the parties. That's set out in the note. And that doesn't require a lot of modification of the language that's proposed. You could put a sentence to that effect in 8.2 talking about procurement plans, because that's really what we're talking about doing, putting a procurement plan together with the utility or the obligated entity to actually consider the potential benefits of at least some long-term contracts or a mix of long and short-term contracts that they address it so that they're making an informed decision as to what's in their best interest in terms of complying with these rules as well as the best interest of all the ratepayers and the shareholders.
MS. WILSON-FRIAS: So one of those two sections is what is suggested. The other question I had is actually for Narragansett. Do you know what -- do you know if or do you remember if in the last resort filings or the standard offer filings whether or not if I go

back the percentage of standard offer load over time is in those documents?
MR. ROBINSON: I know in the last -- or in the last resort filings we provide the percent of load by class. I expect we could provide that for standard offer as well if it isn't in one of the filings already.
MS. WILSON-FRIAS: Okay. If I need a data request, I'll do that.
MR. ROBINSON: Okay.
MS. WILSON-FRIAS: And it's not Narragansett's position that long-term contracts would be prohibited by the statute, right?
MR. ROBINSON: It's not -- Narragansett -- it's Narragansett's position that long-term contracts can't be mandated under the statute, but if Narragansett wished to enter a longer term commitment, I think it could under the statute, but the point is is that in our view anyway it should be consistent not only with the -- it should be consistent with its purchase requirements under the last resort service plan as well. So it would be a separate procurement here, but I suppose we could if it were -- I

mean, I think we have discretion under the statute. It's not precluded to enter into long-term contracts.
MS. WILSON-FRIAS: So you're not prohibited from entering into long-term contracts under this statute?
MR. ROBINSON: That's correct. Sorry. I was too convoluted on that.
MS. WILSON-FRIAS: Thank you, Jonathan.
DR. RAAB: So we wanted to turn to the second issue in Section 8 which was in -- whether or not the contracting standards and procurement plans that are described in Section 8 should also applicable to the renewable energy development fund as administered by the EDC and John Farley from TEC-RI was going to describe that position and then Andy was going to respond to it.
MR. FARLEY: Thank you very much. First of all, I wanted to set the stage for this by identifying who we are, what our interests are in this rulemaking session. We represent large users of electricity in the State of Rhode Island, about 50 members representing about 70,000 jobs, and really, our focus here is to on

the one hand understand the possible benefits of this in terms of additional generation and environmental attributes and at the same time to hold the line on any rate increases that could result from this to make sure -- in that regard to make sure that the costs are prudent, because ultimately, it will always be the Commission who is responsible for rate increases and those will be tied to costs that are prudently incurred.

With that in mind, I don't share the optimism of some folks that we are not going to have a shortage of available generation for renewables for a couple of reasons. One is that while we've heard examples of other states, I think that Rhode Island is unique in a couple of ways. One is that we're in a region of the country that does not have ample natural resources like other parts of the country that could be turned into renewable supply. Secondly, our rate of increase far exceeds those of other states that have been used as examples. We're going from a state that has about two percent renewables up to 16, that's an increase of 14 percent, and that could have a major impact on

rates in the state and we're a small player in a big market and I would just suggest as a matter of course that we should watch what's happening in Massachusetts because they are the 800-pound gorilla and whatever is happening there we're just going to have to deal with. Whatever happens in that market we'll be held captive to it.

Our concern is what happens if there's chronic shortages. There will actually be quite a lot of money that will go from ratepayers to the Economic Development Corporation. I think we heard earlier in Section 7.3 that obligated -- I'm reading verbatim, obligated entities to enter into prospective agreements ahead of time, in effect subcontracting compliance to the Economic Development Corporation, and that was actually assented to by other parties as to the interpretation of that. So with that in mind, we believe that it's to protect ratepayers' interest that whatever can be done in order to make sure that that money is prudently expended will be in the interest of the Commission as well as in the interest of ratepayers.

Now, that said, it doesn't really matter if it's not allowed by the statute. And this is a matter ultimately of legal interpretation, but our view is that it actually is allowed, and I think Section 39-26-6(2) is becoming the equivalent of the Interstate Commerce clause in the United States Constitution because we're using it for several things. But the fact of the matter is it does say that the Commission is to have provisions in the regulations that set standards for contracts and procurement plans for renewable energy resources to achieve the purposes of this chapter and it's a general statement; it doesn't say contracts and procurement plans for obligated entities. It's a general statement, to achieve the purposes of this chapter, and I would argue that if under one of these scenarios the Economic Development Corporation becomes the entity which will be charged with achieving the purpose of this chapter, then their contracts and procurement plans ought to have standards, and therefore, since the Commission is the one who is the one to promulgate those standards, those standards would

apply to that component of the implementation of this law and that's the basis for what we're saying.

In addition to that, there are other places here where the obligated entities are enumerated and mentioned under what is the authority of the Commission and the fact that they're not mentioned is limiting. This No. 2, I think adds weight to the fact that it could be so applied.

In addition to that, in the section that talks about the Economic Development Corporation itself in Section 7 it talks about the Economic Development Corporation entering into agreements with obligated entities to accept these payments that are our concern, and it says it has to be consistent with rules of the Commission, and indeed, that's all we're arguing. We're arguing that whatever payments are made, that those agreements be made in accordance with the rules of this Commission and the purposes set forth. So that's our case. I'm not an attorney but I am charged with representing the interests of ratepayers and it seems to me that this is a

prudent step to take.

MR. C. EATON: I guess I'm next. I'm going to speak for Andy.

MR. DZYKEWICZ: Let me just preface Craig Eaton will be representing the -- our interpretation of this statute, but prior to that just to give the Commission a little comfort that the EDC in executing the requirements of this statute will also be going through a rulemaking. In order to fulfill our responsibilities we're going to have to put in place procedures as to how these monies might be spent. The statute itself calls for two levels of due diligence, one, by a Board of Trustees which is to be set up under this statute to recommend to the second level of due diligence, the Economic Development Commission orders how these monies might be spent. Beyond that, we are anticipating two additional levels of due diligence, one at the staff level, then a management review before it even gets to the Board of Trustees, and finally, once the monies have been appropriated and spent, we're subject to annual review by the legislature as to how we spend any of our monies. So with

that, just to give you some sense of the public nature of what this process would be with the EDC, I'd turn it over to Craig to interpret the -- what we think the law actually says. Thank you.

MR. C. EATON: Thank you. I'm not going to take up much more of your time because there are two submissions in front of you and I really think it is a legal -- you need to do a legal interpretation, and Cindy is probably going to have to do that, and I will say that Silent Sherpa is the only other entity that is with John on this, but I just want to point out that there are two sections, there's 39-26-6 and 39-26-7 in the law, and 6 has to do with the duties of the Commission generally, and 7 has to do with the fund and is generally basically EDC oriented.

26-6 talks about standards, the clause that John talked about, standards for contracts or procurement plans for renewable energy resources and it's our firm belief that's basically the obligated entity and the generator and the contract is taking place between those two and you'll see in the draft rules, I think

everyone is agreed, that we talked about in Section 8, there were two or three sections on exactly what those standards are.

Then you go to 7 and the EDC, they're really charged with two things. They're charged with having a contract between the obligated entity and the EDC. They call it an agreement in 7 and they're also then taking the money pursuant to that agreement and they go somewhere with it, they spend it, however they're going to use it. Pursuant to that in 7 there's a Board of Trustees, I think it's made up of five different people, including the Division of PUC. There's nothing specific at all in 7 that somehow says the Commission is supposed to overlap into that jurisdiction and set the contract standards for how that money is going to be spent, so that's basically our position. And like I said, it's laid out in a little mini brief and I know John has his little mini submission also.

MS. WILSON-FRIAS: Craig, to what does consistent with the rules of Commission 39-26-7 refer?

MR. C. EATON: I think that means

consistent with how the money is going to be gathered or consistent with how the RECs will be gathered, consistent with how the actual money that needs to be paid in and the regulations that talk about how the money is going to be gathered and then ultimately given to the EDC.

MS. WILSON-FRIAS: This question is for anybody. Usually the statute contains the word trust fund. It is a payment received pursuant to this section shall be trust funds. I guess I don't know if the question really ties into our decision, but is that money protected in the sense that once it goes to EDC, it can't be used for anything else, it can't reappropriated by any entity to another purpose? Is it safer than a restricted account?

MR. STEPHENS: I think it's safe to say certainly that was the intent of why that language was in there. Having been involved in the process the idea was to protect those funds and make sure they're used exclusively for the purpose of the renewable energy development trust funds.

MR. DZYKEWICZ: I would certainly

caution that what the legislature giveth, the legislature can taketh away. There's a lot of ways that that money can be taken away from our ability to spend it for the purposes intended. But it's certainly our intention in our regulations that we will develop around this. We'll reflect that statement in our renewable energy project.

THE CHAIRMAN: The word trust had meaning, it wasn't just put in for the hell of it. I know that group that calls themselves the lawyers up there that draft legislation shouldn't get awards for legislative drafting. I assume it has some validity to it.

MR. DZYKEWICZ: That's actually one of the particular nuances that we're going to be looking at very carefully, what this actually implies.

MS. WILSON-FRIAS: I would just hate to see EDC getting this money and then EDC losing it through a budget process.

THE CHAIRMAN: It's like the renewable energy fund, huh?

MR. DZYKEWICZ: Yes.

MS. WILSON-FRIAS: That's all I have.

DR. RAAB: Cindy, you had also given us a question about whether the EDC supported the last sentence in this book which said that the EDC should publish an annual report on the use of alternative compliance payments with reporting requirements delineated in the EDC's rules rather than the rules of the Commission.

MR. DZYKEWICZ: The answer is yes obviously.

DR. RAAB: Then your last question, Cindy, in the body of proposed regulations was about Footnote 5 on Page 25 and that just needs to be deleted. The text from there was taken out and moved to Page 16 I believe as a note to the Commission, so there's no footnote there anymore.

So with that, we're finished with the draft regulations themselves and you had some questions on Attachment A, Cindy, so maybe we can turn to that quickly and then -- I believe you were going to walk through the answers to those three questions.

MS. PEREZ: I also have a few handouts. I didn't make copies for everyone. It's just the

tables themselves. There's two sheets for all of you.

DR. RAAB: Nubia, you were going to respond to those.

MS. PEREZ: So what Cindy was asking I believe is just to go through the tables themselves and explain the differences between the 2006, the 2007 and 2008 tables. In the 2006 early compliance for Calendar Year 2006's table, as you can see, it's much smaller than the other two tables and some of the differences are very obvious. There are no banking -- there's no banking column, there's no ACP column, there's no obligation columns because 2006 is not a compliance year.

MS. WILSON-FRIAS: If I could just interrupt you for a second, I'm not sure if we all have the right chart. Mine just says compliance for Calender Year 2006.

MS. PEREZ: I just gave you guys copies of 2007 and 2008.

MS. WILSON-FRIAS: Okay. So we should be following on along in the attachment now. Sorry for interrupting.

MS. PEREZ: All on the same page? Okay. So again, it's just -- it's much shorter because 2006 is not a compliance year is the bottom line. The differences in the first highlight, the similarities between the table for compliance for Calendar Year 2007 and compliance for 2008, and that's what I passed out. First, I'll go through what Columns I, J and K mean. Column I, the one percent total sales, that's the percentage from new renewable energy resources. Column J, the two percent is the percentage from new or existing and Column K, the three percent for 2007 is the total. So -- and again, the differences between 2007 and 2008, one of the obvious differences is that Columns I, J and K, the percentages differ because every year that number is going to change though Column J will remain at two percent.

So essentially what it means is Column D which is -- I put an asterisk on top -- cannot be less than Column I and Column D and D must equal Column K and Column E must be equal or greater than Column J.

MS. WILSON-FRIAS: Could you repeat

that?

MS. PEREZ: Sure. Column D which is new resources cannot be less than Column I. Columns D plus E must be equal or greater than Column K, and Column E must be equal or greater than Column J.

MR. GRACE: Just a correction, Nubia. I think Column -- you've left off the role of Column F I think, the early compliance certificates, and in subsequent years banking certificates, it's that number added to D that needs to equal I.

MS. PEREZ: Okay. Correction is noted.

MS. WILSON-FRIAS: So D plus F can't be less than I?

MS. PEREZ: Yes. That would be correct. And one final difference, this is minor, the difference between table 2007 and 2008 would be Column F where in 2007 it's early compliance certificates and in 2008 it's banked. Hopefully that makes sense.

DR. RAAB: Is there anything else on the attachment?

MS. PEREZ: I think you also asked in

the REC we described an RPS program manager and that's just a technicality, that's just the person who administers the filings themselves. She or he can also be called the compliance or RPS processing officer.

MS. WILSON-FRIAS: Does the group have any -- I don't believe that was in the definition section. Does the group have any opinion as to whether or not that needs to be defined even though it's only in the attachments?

MS. PEREZ: I believe that we don't feel it's necessary.

DR. RAAB: I don't think we were proposing that this attachment be attached to the regulations to give you the flexibility to change it from time to time. Maybe you need to define it in this stand-alone document.

MR. STEPHENS: I think whoever at the Commission or Commission staff was responsible for dealing with obligated entities.

MS. PEREZ: And Cindy, I believe you also had one more question with regards to Column C which is the total electricity sold in the respective calendar years and I believe, and John

Warshaw, or one of you guys can correct me if I'm wrong, but the question was how long does it take to receive the final reconciled values or the real time obligation for RES in the New England market and my understanding is its takes 90 days plus you have another 30 days to input the data into the GIS.

MR. WARSHAW: I concur with that. It's about four months.

MS. PEREZ: And the last point, if you don't mind me going back to it, you had asked the question between a tradable RES credit and a New England GIS certificate, whether they're the same. They're actually not the same. They're different. Tradable emission credits include NOX and CO2, they're not traded within the GIS -- they're not tracked within the GIS system. The New England GIS certificates identify generation attributes produced during one megawatt hour of generation from a renewable energy generation unit. The GIS tracking system is simply whether the GIS includes in the credits in terms of the bilateral contract.

DR. RAAB: So I guess this completes

what we had for you and if you have any other questions or thoughts that you wanted us to respond to, we're here to do that. We have one other present for the Commission which is for Cindy in particular which is Bill Short did have another very careful read after we handed it in and he's got some formatting and clean-up editing suggestions which we will provide to you and you can look through as you're putting together the regulations.

MS. WILSON-FRIAS: If you'd like to e-mail me a copy, that would be much appreciated or did you write them?

DR. RAAB: It's all handwritten.

MS. WILSON-FRIAS: If people don't have any other questions, before I accept -- Jonathan, maybe this has already been said, but since I wasn't here this morning I want to say it now. I said to Jonathan before I sent the e-mail that overall I thought that this document showed that a lot of hard work had gone into it and I got something that, although it took me a while to get through it, I actually think I understand which was really the goal of this because I think

had the Commission had to sit down and do this with one single consultant, we would not have ended up with this kind of product this quickly, and so I think that the process so far has worked quite well and I appreciate all of Jonathan's work and all of the work everybody else who I know attended a lot of long meetings and I'm sure there were heated discussions at times, but it looks like a really strong piece of work came out of this, so at least from my staff position, I want to thank everybody.

DR. RAAB: Cindy, could you just clarify for everybody who's been asking me exactly what the process is going forward and when it would be appropriate for them to provide additional comments at a later date?

MS. WILSON-FRIAS: Well, what happens next is that the Commission will issue proposed regulations officially. It will be noticed in the newspaper. It will happen at an open meeting. It won't say the parties disagree on this. We'll actually have to print something. At that point the clock starts running. There will be an initial 30-day comment period

following that, following notification in the newspaper that the rules have been proposed. You'll also, as members of service list, receive notification that the rules are up on the website for review. You can send in written comments. The deadline will be posted as well. There will also be a hearing, and I don't have my calendar in front of me, it's in October, I believe it's on a Wednesday.

MR. HARTLEY: I think it's the 12th.

MS. WILSON-FRIAS: I believe it's Wednesday, October 12th, probably at 9:30 where if you want to provide any verbal comments or come and see if anybody else shows up to provide verbal comments and written comments are accepted up until the deadline.

Then what will happen is the Commission will look at all the comments, see if the changes -- if it needs to make any changes, if those changes are technical or substantive. If the changes are technical, the Commission will approve the rules and then they'll be filed at the Secretary of State's Office January 1st. If there are substantive changes that would alter

the rights of the parties or the obligations of the parties outside of what was commented to or what we've discussed today, there would be another comment period. That has happened in the past. It doesn't usually happen. But that's what the process looks like going forward.

DR. RAAB: Okay.

COMMISSIONER HOLBROOK: Does anyone else have any other comments for record or any closing statement by anybody?

MR. SHORT: Not really a closing statement, per se, but we're going to have our tour of the Johnston landfill. You're all invited. Some of you have accepted to come. I've got the agenda here. I understand all of you are Rhode Island residents with few exceptions, so I don't think you need directions to the landfill itself. It will take about two hours. You'll find it quite informative. It's Rhode Island's largest renewable energy resource. It's actually about the largest facility that's been added of renewable energy in New England since the start of deregulation. So I think we'll have a good presentation and excellent

tour.

COMMISSIONER HOLBROOK: I would thank everyone for your attendance. An excellent job has been done, I'm sure we'll hear more about it in the future, and if there are no other comments, the meeting is adjourned.

(ADJOURNED AT 2:55 P.M.)

C E R T I F I C A T E

I hereby certify that the foregoing is a true and accurate transcript of the hearing taken before the Rhode Island Public Utilities Commission, on August 31, 2005, at 10:30 a.m.

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JO ANNE M. SUTCLIFFE, RPR/CSR
Notary Public, State of Rhode Island

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