STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

January 17, 2013 - 10:11 a.m.
Concord, New Hampshire

RE: **DE 12-362**
ELECTRIC UTILITIES:
Rebate of Excess Regional Greenhouse Gas Initiative Allowance Auction Proceeds to Default Service Customers.
(Hearing to receive public comment)

PRESENT: Chairman Amy L. Ignatius, Presiding
Commissioner Robert R. Scott
Commissioner Michael D. Harrington

Sandy Deno, Clerk

APPEARANCES: (No appearances taken)

Court Reporter: Steven E. Patnaude, LCR No. 52

I N D E X

P R O C E E D I N G

CHAIRMAN IGNATIUS: I'd like to open the hearing in Docket DE 12-362, regarding the new statutory requirements of a rebate of excess Regional Greenhouse Gas Initiative allowance auction proceeds to default service customers. By order of notice, we required -- we scheduled a hearing today to take public comment on the appropriate way to implement the new statutory provisions that creates an Energy Efficiency Fund, and designates how those funds are to be allocated between Core Energy Programs operated by the utilities and rebates to customers. But the mechanics of how that's to be done is always more complicated than you expect it to be. So, we appreciate people coming today, thinking about it, and giving us their thoughts on the best ways to implement that.

It's a public comment hearing. We won't have people testify and be put on the stand for cross-examination, but we would welcome people's thoughts, questions, proposals, on what they think is the appropriate way to do it, and some give-and-take among the Commissioners as well. So, I don't think we need to do appearances in the normal sense. Ms. Amidon, yes?

MS. AMIDON: I agree with your -- that

last comment. I did want to inform the Commission that Attorney Gary Epler, from Unitil Energy Systems, Inc., had planned to be here today. But he called me late last night and informed me that he was going to have to be in Boston this morning. He has prepared written comments and will be filing written comments with the Commission probably before the end of this week. But I just wanted to let you know that he sends his regrets that he could not be here this morning.

CHAIRMAN IGNATIUS: All right. Thank you very much. And, I understand there's a horrendous accident on 93, south of here, and there may be people still struggling to get here, which, of course, we understand.

If there is anyone who has thought about the mechanics of implementing this statute, and has a proposal to make, well, maybe we should start with that. If it's only questions posed on what to make of it, we can then move to that. But, if there's anyone who has, in their mind, has a sense of the right path to follow, we'd be interested in hearing it.

MS. AMIDON: If I may, madam Chairman?

CHAIRMAN IGNATIUS: Yes.

MS. AMIDON: At the outset, I would just

inform the Commission that I did talk with the representatives for the electric utilities. And, we have agreed on, I don't know if you want to call it a "process", but that's probably the best description. What we hope, after, if we can't do it here this morning, and maybe in the technical session that follows, is to develop a methodology where we could agree on certain elements about how, for example, to allocate any proceeds in excess of a dollar, and other issues such as that, and have the Commission review that. And, in its determination, it could approve that on an order *nisi* basis. While each rate change, in other words, in each instance where an electric distribution utility may credit that amount back to default service customers, they could do that in one of the ordinary periodic default service filings they make with the Commission, so as to make this a more administratively efficient process for both the Commission and for the utilities.

I also know that Mr. Mullen, the Assistant Director of the Electric Division, has also given this a great deal of thought, and probably will be able to respond to additional questions. But I wanted to let you know that we agreed on this sort of overall template on how to approach the implementation.

CHAIRMAN IGNATIUS: So that the rate change effect could be rolled into sometime when rates are being effected anyway, and not have a separate order and separate date that it has to go, sort of work it in to what works best for the Company?

MS. AMIDON: Correct. And, also to obviate the need for the Commission of have a hearing on approving the methodology. If it doesn't, you know, you could always go ahead and have a hearing. But, if we all, for example, the goal would be to get the parties to agree how to do it, present that to the Commission, and request that the Commission approve it. And, if you would want to go to hearing after that, that's, obviously, your choice.

CHAIRMAN IGNATIUS: Okay.

CMSR. HARRINGTON: And, just a question that's been -- all the utilities and the Staff have looked into this, has the OCA been involved in that discussions?

MS. HOLLENBERG: Thank you for the question. Ms. Amidon did mention to me the concept this morning. So, I was generally aware of the thought around working collaboratively to develop a methodology to use in a more generic way, and then taking further steps on a utility-by-utility basis after that.

I think it sounds like a reasonable

approach. I guess, for the OCA, we don't have any specific recommendation, as far as a process would go. Only a few concepts or goals that we would like. You know, that the process to be guided by, namely, that the refunds are timely, that they're done in an efficient and economic -- as economic as possible manner. And that, to the extent possible, the utilities do it consistently, so that customers are able to understand, and there isn't confusion among customers from different utilities. So, we're open to the utilities' knowledge of what their systems are capable of with those goals in mind.

CHAIRMAN IGNATIUS: Would you carry the question of consistency to the point that everyone should see it March 1st? Or, if one company was in for a change March 1st and another in for a change on April 1st, that would be okay?

MS. HOLLENBERG: Yes, I think, if it is -- it's going to be in through a default service, so that's a reconciling mechanism. And, so, there wouldn't be a harm to a customer in getting it at a different time. I guess there's some delay in receiving the money, but they receive the value of the money when they receive it. So, I don't see that as being a problem.

CHAIRMAN IGNATIUS: All right. Are

there others who have either sort of broad principles they would suggest in the way that Ms. Hollenberg just did or proposals or concerns you have in how to implement it, as you read the statutory requirement? Mr. Dean.

MR. DEAN: Yes. And, you know, I came with some very general goals to state on behalf of the Cooperative, and also with some, although still somewhat general, addressing the issues that were specifically outlined in the notice. If it turns out that the idea is that the parties should be getting together to work through something, I don't want to be too repetitive, but I can go through them and at least get that on the record. So, --

CHAIRMAN IGNATIUS: Yes. I think we'd be interested in what you're thinking currently, and then further refinements as you meet after this.

MR. DEAN: So, first of all, I guess general principles, and these four I don't think would come as any surprise to anybody, I think. But, first, that any system effectively rebate the auction proceeds, as required by the statute. And, second, that that be done in a manner, which is both transparent and verifiable. And, third, that the system for effectuating the rebates should minimize administrative and regulatory expenses and burdens. And, fourth, and this, I think, goes to the question you were just asking about, the timing of rate changes, that the system for effectuating the rebates should minimize additional complexities or confusion regarding the energy service rates as established by each of the utilities.

And, then, with those four general principles, looking at the items that were listed on Page 2 of the notice, and going through those as they're numbered. The first was the "allocation basis" question. And, the Cooperative, and not having really discussed this everyone else, so, it's own thinking initially is that the allocation basis should be based on utility-specific historical energy service kilowatt-hour load data. While the Co-op coupon doesn't have a strong view on exactly, you know, what period of time should be covered by that, initially seemed to make sense that the most recent 12-month data, which is always available to the utilities, would probably be the data that more closely matches the load that the utilities would expect to be serving during the time period when the rate's in effect.

The second item that was raised was I think whether the number of default service customers is relevant to the calculation or the allocation. And, at least in the internal discussions, the Co-op didn't see how that was a relevant factor in determining what the allocation should be, whether you had one or 10,000 default service customers, it's a kilowatt-hour basis calculation, so that that would be -- kilowatt-hours of default service seems to be the basis for allocating between the various utilities, I would think.

CHAIRMAN IGNATIUS: But are you using kilowatt-hours of energy delivered to default service customers or kilowatt-hours delivered to all customers within your system, which would be default and --

MR. DEAN: It would be -- I guess, for the Co-op, it's a little -- the terminology is a little different. But I would -- I'm using "default service" or "energy service" interchangeably. Basically, consumers of the utility that are getting their energy from that utility.

CHAIRMAN IGNATIUS: So, you would only be measuring the default service load when you're doing the allocation?

MR. DEAN: Yes.

CHAIRMAN IGNATIUS: Not the throughput on the system, only the default service load?

MR. DEAN: Yes. The third one was

whether the allocation should be based on some calculation of the amount of RGGI costs that had actually been paid by consumers. And, again, without really consulting others, the Co-op's internal analysis, at least from how it obtains power supply, didn't know that that was a knowable piece of information to any degree of accuracy. So, it didn't see how that was something that could be worked into the calculation. I mean, basically, the additional RGGI costs -- RGGI-driven costs that consumers pay is based upon, in theory, what market, you know, how the market has somehow been moved somewhat by the fact that the auctions take place. And, if you have, as the Co-op does, many wholesale power supply contracts, with different entities, over different time periods, I don't think there is a way to say "this is how much the power supply price is changed by the fact that the RGGI is in existence.

The fourth, as far as, I guess, a combination of factors, again, our focus would be on the allocation based upon default service kilowatt-hour historical usage.

And, then, the fifth one listed was sort of the more general question about "is it going to be quarterly? How are you going to make the allocations and make the rate changes? And, I think, consistent with the general principles that I described, it's the Co-op's view that the rebates should be effectuated by means of reconciling -- fully reconciling accounts. And, that any under and overrecovery balances would simply be taken into account by each utility when they're setting their periodic default service or energy service rates, using the same timing for those rate changes and methodologies that each utility uses. I am no expert on what the other utilities' processes are. The Co-op currently changes its energy service rates twice a year, in an effort to maintain some degree of seasonality in its rates, so as to reflect price signals that at least more closely approximate what happens in the marketplace, than they would if they just had an annual rate adjustment. But I guess our view is to try to make it less complicated and less confusing. It's really just a -- the rebates would be a credit that gets put into the calculation for what those rate changes are. And, you know, through the working group or however it's done, obviously, we need to have a form or a system, so that the Commission can see that, yes, we transferred this amount of money to the utility, and, yes, we see it's being properly accounted for, and it's getting back to consumers in the form of decreases in the energy rates that they otherwise would pay.

And, so, really it's, I think, the central point here from my -- from the Co-op's perspective, is that, you know, the changes should be somewhat seamless from the perspective of the consumers. That we don't need to have additional new rate changes periodically during the year, we just need to reflect these credits in the rates as they would otherwise change anyways.

And, finally, I think in the list there is a question about whether there should be a separate line item on the bill, which would show this credit. The Co-op does not favor that. We believe it adds additional expense, adds additional -- another additional item to bills that have gotten pretty complicated as the years have gone along to begin with. And, frankly, it isn't like there's a line item on the bill for the costs associated with RGGI. And, so, to me, it doesn't seem to make much sense that there would be a separate line item to show the credit you get for those, you know, costs being reduced.

And, that concludes the comments that I had prepared.

CHAIRMAN IGNATIUS: Thank you. That's very helpful. Thank you. Others with thoughts on the issues that the implementation raises? Mr. Fossum.

MR. FOSSUM: Yes. Thank you. Matthew Fossum, for PSNH. And, to the extent there are questions on specifics, I'll lead off by saying that I would defer to my colleagues from the Company, who are much more familiar with this than I.

I'll pick up first where Mr. Dean left off, and say that PSNH also does not favor having this rebate called out as a separate line item on the bill, for essentially the same reasons as he had mentioned. And, in addition, we don't know the amount of money that will be available and distributed to customers ultimately, but it's possible at least that the amount of money would be relatively small, as compared to the default customer base, and, as such, would be a very tiny amount, to have a separate line item for a potentially very tiny amount just doesn't seem necessary.

With that said, we prepared some comments also, which I will, I guess, sort of stray from a little bit, in light of how the conservation has gone so far. But PSNH sees essentially the same issues that others have mentioned, and kind of boils down to two questions, in our mind. And, that's "how is the available money to be allocated out to the utilities?" And, then, "how is that money then rebated to customers?"

And, with respect to the first question, the allocation, it's PSNH's position that the allocation of the available money should be based upon the costs that a utility's customers have incurred for complying with RGGI. For PSNH specifically, those costs are -- come from two sources; both the RGGI costs associated with PSNH's generation fleet and its use of its generation, as well as the costs embedded in the power that PSNH purchases on the open market. We believe that that's the most fair, appropriate way to allocate funds, because it recognizes the special costs that PSNH's customers bear.

I'd also note that, while there's not a lot of -- at least I wasn't able to find a lot of recorded history on House Bill 1490 that led to this law, in an early version of this -- early on in the legislative process, Representative Garrity had noted that, because New Hampshire would not be leaving the RGGI Program, the intention would be to reduce the negative impact of RGGI costs on ratepayers, particularly PSNH's ratepayers. So, the allocation that PSNH is proposing would, we think, meet that stated intention.

CHAIRMAN IGNATIUS: Before you move on, can I ask you --

MR. FOSSUM: Sure.

CHAIRMAN IGNATIUS: -- how would you know the costs embedded in power that's purchased on the open market?

MR. FOSSUM: Again, I would defer to the specifics, but it is my understanding that that amount is -- can be calculated and can be determined. If you'd like greater specifics, I would turn to Lynn Tillotson for a more thorough explanation.

CHAIRMAN IGNATIUS: That would be helpful. Why don't you swing the mike over for the reporter's sake.

MS. TILLOTSON: Good morning. Lynn Tillotson, with PSNH. The specifics of how you would calculate it certainly could be debated. But I will remind people that back along, as part of the disclosure for environmental attributes, that a similar effort was looked at. And, so, to the extent that you have utilities purchasing load in the market, you can look at ISO's average environmental emissions, the CO_2 emissions, and that that number would be representative of the CO_2 emissions associated with any of the market purchases, as a fair way across the board, all the utilities that are buying in the market would be buying through the ISO process, and they do have an average CO2 emission associated with that. So, that could be used to calculate what would be an expected CO2 emission amount with those market purchases.

CHAIRMAN IGNATIUS: And, then, you'd have to have some monetary value to put to that?

MS. TILLOTSON: Correct. And, during the legislative process, clearly there we thought the best potential representative were the four quarterly auction prices. Every RGGI -- the RGGI, Inc. people do four quarterly auctions a year. So, you could use the average of that to turn your load into CO2 emissions, would then be an associated cost. And, what that would allow you to do is truly compare the cost of compliance with those purchases in the ISO market and still care for the actual emissions, because we do have actual emissions associated with the PSNH fleet. And, back through the legislative process, the difference between PSNH and the other utilities was repeatedly discussed by legislators, by the Ross Gittells of the world, recognizing that RGGI really did impact utilities slightly differently.

So, we would see that, if a utility only had market purchases, you could certainly calculate their total compliance costs using an ISO average environmental emission rate, times an average auction RGGI amount. And, for the hybrid of PSNH, you could use that same approach for its market purchases, and add to it the known amount of emissions. And, again, I would assume the auction price is an average, to keep an equitable kind of comparison apples-to-apples. And, at the end of the day, any calendar year, I think you could say this is what customers paid for CO2 compliance as a result of New Hampshire being in the RGGI Program.

CMSR. HARRINGTON: Just can I follow up on that? I'm trying to -- maybe I can state what you said in more shorter terms. For the generation, for the power that Public Service generates themselves, they would simply say "this is how much we paid in RGGI, because of our emissions." And, that would be a known absolute number. And, I'll get back to that in a second. But, for the part that you purchase, you'd be just saying, like every other utility, you're just basically going to take an average of how much is paid per megawatt-hour for RGGI on average across New England? Because you wouldn't know, even on a purchase power agreement, a supplier may be giving somebody, you know, on Monday it may be coming

90 percent from a nuclear plant, on Tuesday it may be coming from a gas plant more, on Wednesday some of it's from wind. So, you would just be strictly an average is what you're saying?

MS. TILLOTSON: Which is really very similar to what I think the -- what do you call it, the --

MS. ARVANITIS: Oh, the disclosure label?

MS. TILLOTSON: The disclosure label does the same thing. It looks at the whole year, and says "at the end of the day, you may not know what Monday, Tuesday, Wednesday was, but, for the whole year, this is the average CO2 emission rate." And, we could even estimate it slightly easier, if you want. Let's say that ISO-New England has said "at the end of the year, there's about a half a ton, a thousand pounds per megawatt-hour." And, we know, in the RGGI world, there is about two dollars per RGGI allowance, or two dollars per ton. So, you really can presume that there is about a dollar's worth of cost to every ton of CO2. And, that would be, I would say, similar to all the market purchases, regardless of which utilities.

CMSR. HARRINGTON: So, you would be saying that the same rate would be then, for all utilities, it would be so much per megawatt-hour of supply to their default service customers, and they would simply -- so, everyone would pay the same rate?

MS. TILLOTSON: Uh-huh.

CMSR. HARRINGTON: It would just vary according to load.

MS. TILLOTSON: That's -- that's an approach that we thought was fair, so that everybody was treated similarly.

CMSR. HARRINGTON: And, is there anything that needs to be adjusted for Public Service, because of the fact that there are times when they sell some of their load into the market? And, we've been led to believe that it's not always 100 percent, because of various market conditions, so that sometimes they're selling power into the market that they generate, and how would you account for that factor? Because you'd still be paying the RGGI amount, but that wouldn't be being passed on necessarily directly to your customers.

MS. TILLOTSON: My instinct is that it's cared for with the overall accounting on an annual basis through our ES rate. But that is a nuance that you would have to test, it's probably not the only test. Whatever system we come up with, I think we'll say it's going to work most of the time, and then we'll have to go back in and just see if there's any unique aspects of this, for any of the utilities that has some little distinction. But we certainly were just thinking that it would be cared for similarly across all customer base.

CMSR. HARRINGTON: It also may be small enough that it's insignificant. I just don't know how much power you actually generate and sell into the market that doesn't end up with your consumers. So, that's another factor to look at.

MS. TILLOTSON: And, I think that was the other thing we noted that, as you look for perfection, and that may be difficult, some of those costs may be sufficiently small that they are okay not to be perfect, and others will absolutely need to be cared for fairly.

CMSR. HARRINGTON: Thank you.

CMSR. SCOTT: So, can you --

MS. HOLLENBERG: I guess -- oh, I'm sorry, you have a question. I had a question, a follow-up question for Ms. Tillotson, if I might. But I don't want to interrupt you.

CMSR. SCOTT: Well, I'll start, and then maybe --

MS. HOLLENBERG: Okay.

CMSR. SCOTT: That probably won't help your question, but --

(Laughter.)

CMSR. SCOTT: I'm still trying to follow this. So, I understand, generating, you're paying -- you're directly paying RGGI allowance costs, and I get that. You have an obligation under RGGI, being a generator. How do you equate that or what's your thought on how you equate that into a percentage? Obviously, you don't want to be in a position where there are other default service customers from other companies. You don't want to be subsuming, or maybe you do, but they would not like it probably if you took all the -- you know, whatever the rebate amount was just because you had generation. So, how do you equate that into a percentage that fits into a formula, if you will?

MS. TILLOTSON: I would -- I started at the place where I said that RGGI compliance is associated with CO2 emissions. And, what I was hoping to do is that you take any generation, any megawatt-hour produced, would have a CO2 emission that you would eventually turn into a cost. So, you would have a RGGI compliance cost associated with our generation, which I would say you can do CO2 tons, and I would still probably use the auction price, that would avoid us going out and saying "well, we can pay five dollars, and we don't care, because it will be reimbursed." So, for fairness, I would say you would always use the average rate of those RGGI auctions, and that would turn into a cost. And, then, all of your market purchases would have a CO2 emission component that we would use the ISO average emission rate. We would turn that into a cost using the average RGGI auction.

So, at the end, I would have a total compliance cost associated with RGGI. Some of it would be a PSNH customer, some of it would be a Unitil customer. Once you totaled that, I would say the simplest and fairest thing to do would be to prorate it. Somebody has a 50 percent piece of that, somebody has a 25 percent piece of that. And, it disconnects where you are with RGGI compliance costs as a total, versus RGGI auction revenue. Because, to your point, we may know what we think that relationship is today, it may change down the road. So, that would keep everybody in a proportionally same, if they're perfect, as costs in the RGGI auction, everyone would have 100 percent, conversely, everyone would be at 50 percent of their compliance. So, it would just be a total ratio of the total costs to New Hampshire customers.

CMSR. SCOTT: Okay. That's helpful. Thank you.

CHAIRMAN IGNATIUS: So, two questions that occur to me. What you do with PPAs? Which is another source of the power that you deliver, that isn't either the market-based one that you described or your own generation. How do we figure that one in?

MS. TILLOTSON: To the extent that a PPA is associated with a wood burner, they don't have a RGGI cost associated with it. So, I think we would be able to be clear which megawatt-hours those are, agree that they don't have a RGGI component cost. So, math that starts out like it might be pretty complicated, once you get all the numbers down into a table, I think people would agree that those could be treated differently for the right reason, not having a RGGI rebate piece to it.

CHAIRMAN IGNATIUS: And, so, that actually feeds perfectly into the second question, which is how is your method different from just allocating on a default service load basis that Mr. Dean was suggesting? What does yours pick up that is different, and that would be one of the things that you could not be including, default service load that is served by a wind contract or a biomass contract, that that -- that there would -- it's probably a fairly small distinction, but that you're looking at really looking at the compliance costs of RGGI alone and allocating that, rather than looking at the default service load and allocating it?

MS. TILLOTSON: I believe it's because we think that that ties back very specifically to what costs are being incurred by New Hampshire customers associated with RGGI, which is why we kind of chose this path. Because it does recognize that there are some generating, like a PPA, like a wood burner, that do not have a CO2 emission that didn't have a RGGI piece, your hydro units don't necessarily have it, a CO2 piece. So, in our calculation, they wouldn't have added in CO2 emissions, and that would be appropriate.

So, I think it's simply trying to tie back to CO2 emissions and coming up with a proxy cost associated with it, rather than just assuming every megawatt-hour has the same CO2 profile, which we know is not true.

CHAIRMAN IGNATIUS: All right. Ms. Hollenberg, can you remember what you were going to ask?

MS. HOLLENBERG: I think I can. And, I'm just trying to understand a little bit further. So, basically, PSNH is suggesting that, for its own generation, it uses its actual costs for RGGI compliance to calculate what percentage of the return would be. It uses actual costs, is that correct?

MS. TILLOTSON: And, the only reason I'm going to correct that is, is I would say it's going to use our actual CO2 emissions.

MS. HOLLENBERG: Yes.

MS. TILLOTSON: But I would have suggested that we continue with the auction floor price, the auction clearing price. I would tell you that's the price we're paying, because we're in the auction, that's what we're paying. But I quickly play devil's advocate to my open idea, and I was thinking you do not want PSNH to be able to go out and pay a premium and think they're going to come back and have it reimbursed as actual. So, it keeps us honest to the process.

MS. HOLLENBERG: Okay. I guess I'm just curious, I don't understand why it can't be allocated on RGGI compliance cost basis for everybody? I guess, is that a different way of doing it and why couldn't it be done that way?

CMSR. HARRINGTON: Well, part of I think the issue there is that people don't know exactly what it is. If you go out for a default service contract, say whoever, one of the companies, let's put PSNH aside, because they're greedy with their generation, they go out and they say "we want this much electricity." And, what a supplier is going to say, "we'll put in a bid," the bidder comes back and says "we will supply it at this price." They don't necessarily know exactly how much is being paid for RGGI. I mean, for example, if the contract came from NextEra, maybe it includes or maybe parts of it are coming from Seabrook. If it's from other supplier, maybe they're getting -- maybe some of it's wind, some of it could be coal, some of it could be natural gas, that mix. And, maybe each one of those per megawatt-hour has a different RGGI cost, from zero, for non-emitting, to, you know, coal being the highest. So, I just don't think there's a way to nail it down.

But there was a follow-up question to Public Service I want to ask. I think, if I've got this, let's just start with the allocation per utility. So, we say there's X amount of total default service load in New Hampshire. And, then, in order to figure each utility's percentage of that, to see how much a piece of the RGGI pie they would get, they would -- well, what I'm hearing is, you'd say "what's your total default service load?" You'd subtract, if you had any specific contracts with --

or PPAs with -- unique to a specific non-emitting plant, like a wood burner or a wind plant, where you would know, whatever you bought from that particular facility, does not have any RGGI costs associated with it. So, you would subtract that out. And, then, you would account for your generation separately, and then -- and, again, that would be subtracted out, because the costs there would be dealt with through the -- what you actually bought for RGGI credits. And, then, that would leave you with a number of megawatt-hours, and that would become some percentage of the total default service load for the entire state. And, would you then make that your percentage or are you going to adjust the total default service load, this gets very complicated, the total default service load for those total amount of PPAs that serve default service load with non-emitting -- from non-emitting suppliers? So, would you just subtract that both ways? In other words, the first question is, how would you establish the total amount of default service load? Would it -- if you knew you had or any utility had a PPA that was uniquely and directly with a non-emitting supplier, let's say a wind farm, they supply X amount of megawatts in the whole state through the total PPA, should that be subtracted out of the default service load total before we start figuring the percentage?

MS. TILLOTSON: I can't tell you if the math would be the same. What I was proposing, when I did my spreadsheet, was that you would start with a certain load. And, you know, you could have a utility and you would have a certain load. Now, for example, in your example, if you had a PPA, I would put next to that PPA a zero, for zero CO_2 emissions. And, with a market purchase, I would put the 0.5 CO_2 tons per megawatt-hour that I have as my ISO average.

If it was a PSNH fleet, I would have an actual average, because I would know my CO_2 emissions and I would know my megawatt-hours. So, for every megawatt-hour, I would be able to calculate a CO_2 emission associated with that generation. And, then, my next column would be, and I'll use the $1.94 auction price that the revenue has been. And, I would end up with a compliance cost associated with RGGI. I would sum that, and figure out percentagewise which one, how much of those -- where does the compliance costs end up? It's going to be some portion of that total. And, you would go back in and bracket them by whose utility. So, PSNH would have a market cost, they would have a PPA cost, which would be zero, it would have a fleet cost. And, you would simply sum those by utility to figure out how much of the percentage, you know, somebody would have a 25 percent, somebody would have 35 percent. And, you would know that and go back in, and then say "how big is that RGGI auction rebate pie?" And, they would have that percentage.

CMSR. HARRINGTON: I guess what I am trying to say is that, that all has to be done, and I understand and I follow what you're saying. But it's a percentage of something. So, first, we're going to have to establish what is the default service load, I'll call it, for lack of a better term, the RGGI default service load in New Hampshire. So, if the total amount of default service load in New Hampshire is X, and the total amount of PPAs that the various utilities have, directly with non-emitting sources, whether it's wind or wood burners, and that's why, would you then say that the total RGGI default service load is X minus Y? Would you adjust the total that you're starting with to account for those non-emitting purchases?

MS. TILLOTSON: I believe it can stay in the math, because it will show up as a zero. So, it's okay to leave it as a total. But, I will definitely say, it would be better to do it in a spreadsheet and really test whether --

CMSR. HARRINGTON: Okay.

MS. TILLOTSON: Because, I think, to your point, once you do it both ways, I'd like to think we would agree that there's a right way, so it becomes the correct way, and one way says "oh, no, that's skewed the numbers." Which may be why at first we do need to make sure we're all clear on the objective. And, so, I'm clearer on that. And, then, the math, you want to just make sure its supported, the objective.

CMSR. HARRINGTON: Okay. Well, I guess what I'm trying to say is that, let's just say there was one utility had a large amount of PPAs with non-emitting sources. So, they would have a lot of their default service load, let's just make up a number, say 50 percent of it was coming from PPAs from non-emitting sources. So, they would be paying, on their total default service load, a smaller RGGI component than another utility, who had zero PPAs with non-emitting sources, where all -- every megawatt they bought would be coming -- would have a RGGI component into it. So, we shouldn't be comparing those the same.

MS. TILLOTSON: Right.

CMSR. HARRINGTON: So, I think we have to adjust the total to account for that, to subtract out the non-emitting PPAs in New Hampshire, from --

MS. TILLOTSON: Right.

CMSR. HARRINGTON: -- to when we set the RGGI default service total, if you will.

MS. TILLOTSON: I believe we're agreeing on the same outcome, and the math would have to support that.

CMSR. HARRINGTON: All right. Thank you. This is so simple.

MS. TILLOTSON: Yeah.

CHAIRMAN IGNATIUS: And, because, if we end up with an approach that, for all of the market-based supply you use the ISO average, and there may be other proposals to do otherwise on that, so far we haven't heard any, if you did that, then it really -- the only people with the PPA situation would be PSNH, right? Unless, does the Co-op? The Co-op would have some as well?

MR. DEAN: Oh, certainly. Yes. I can't tell you right now what the exact percentages are. But, for example, I think the Co-op's currently about 11 percent of our supply is renewable. Presumably, almost all of those would sort of fall out of the calculation. And, I would guess that if you're, you know, it's probably about 30 percent of the Co-op purchases are on the market, meaning, you know, day of or day ahead, that type of thing. Everything else would be PPAs.

CHAIRMAN IGNATIUS: Oh, all right. So, I was way off.

MR. DEAN: But I'm presuming that the PPAs that are just the standard PPA, where it may be a heat rate, you know, or some other kind of contract, that they would probably be using the same calculation. These are all proxies anyway. We'd be using a proxy of the auction price. So, that really wouldn't be a huge calculation. It's just that, I think in my comments I was saying "the costs aren't knowable". I mean, they're not. We're talking about, no matter how we do this, we're talking about filling in proxies. And, you know, we can get precise. And, I just don't know how it all flows out. When you start doing the spreadsheets, whether all these calculations really amount to much of the change in what the end product is, if you take a simpler route.

CHAIRMAN IGNATIUS: Right. And, I think that's, obviously, the ultimate goal that I don't think anyone would disagree with, that the balance has got to be there. That, if getting everything down to the penny costs an enormous amount, but is really not very different than using a view proxies, and other ways of getting close to the result, that may be appropriate.

Other -- I think, Ms. Tillotson, we probably cut you off. You probably had more to say and, Mr. Fossum, you probably had more to say. Didn't mean to derail you. And, then, we will move onto others.

MR. FOSSUM: No, that's fine. It's helpful for everybody to understand what is going on. I just wanted to go onto the -- sort of what we see as the second issue. And, it's just the -- I hope an easier and more straightforward issue, having to do with how the utilities actually take whatever amount of money they get and ultimately rebate it to their customers. And, from our perspective, I think we share some of the same goals that Mr. Dean spoke about, of, you know, effective and transparent, verifiable, and having low administrative burdens. So, what we would look at is to take whatever amount of money there is, and for -- just for an example, beginning this year, we would, for rates that would take effect for PSNH on January 1st, as we traditionally do, as part of our Energy Service filing, there would be a calculated RGGI credit in there. And, so, as part of the overall energy service rate, the credit would be included in that calculation. That way it would certainly go only to default customers, which is, we understand, is a directive of the statute, that it be refunded to default customers. And, that would be administratively relatively straightforward. It would be included in an already existing filing. And, because, as I had mentioned earlier, it's certainly possible that once whatever amount of money there is to spread out over the entire base of default customers, that money may be very small. It's simply another adjustment within the ES rate that wouldn't need to be called out specifically.

And, just to be clear, we would propose to set it on an annual basis. And, the reason for the annual basis is again, much like the last reason is, to set it more frequently than that, you're dealing with a partial year worth of RGGI dollars. And, so, whatever amount this pie is would then be half that size. So, to do it annually, that would mean that there's a significant -- presumably a significant amount of money in there that would be rebated and would make a meaningful difference. Well, I guess that depends on how you define "meaningful". But there would be a change that would at least be large enough as to not be imperceptible.

CHAIRMAN IGNATIUS: All right. Questions? Commissioner Scott.

CMSR. SCOTT: Thank you, Attorney

Fossum. I want to still go back to the earlier discussion, so I apologize. I just want to -- I don't want to put words in anybody's mouth, as usual, but the plain text of the law, as I understand it, says "the rebate should be to all default service electric ratepayers in the state on a per kilowatt-hour basis." So that the plain text to me would mean, uninhibited by the rest of the discussion here, would mean take all the default service customers and rebate it equally. I mean, that's the plain text as the way I read it. Why would we go beyond that? And, I think I probably know that from the earlier discussion, but I just want to understand that.

MS. TILLOTSON: I certainly was influenced by much of the discussions for many years with RGGI, and the debate that has gone on with the State of New Hampshire saying "should we stay in" and "should we be out of the RGGI Program". And, that debate often ended up being the discussion between PSNH being slightly different. So, if RGGI had been left, that we would not have had RGGI costs. And, you're probably as familiar with that, if not better than anyone here. So, recognizing that that had been the discussion through the whole legislative process, I think you can still start with that kilowatt-hour basis, and then recognize that the RGGI compliance cost associated with those could be illustrated as we've talked about and turned into dollars. So that, at the end of the day, you truly have the default service customers that PSNH retained being fairly treated in this, and not just kind of brought into the average. And, I know we've worked hard to do that before with the labeling, to have that uniqueness. So, I was not thinking it was completely out of line, in fact, more in line with the discussions that went on, though, it got captured relatively simply in the statute language.

CMSR. SCOTT: Thank you.

MR. FOSSUM: If I may add, I mean, looking at the statute language, it says that "it shall be rebated to all default service customers on a per kilowatt-hour". So, to me, I had read that initially as "the rebate is on a per kilowatt-hour basis". How the allocation to the utility happens is not specifically called out. So, to the extent that there had been recommendations that it be flowed through the default rate, then that would, I think, comply with at least that reading of the statute.

CMSR. SCOTT: Okay. Thank you.

CHAIRMAN IGNATIUS: Mr. Warshaw, you've

been trying to get in on this.

MR. WARSHAW: Yes. No. John Warshaw, Liberty Utilities. The first thing is, I do agree that whatever process that we develop should be, you know, timely, efficient, and approached consistently across all the utilities in New Hampshire. Liberty Utilities is, I don't know, unique, I can't speak for Unitil, but we only buy our power through full service all-requirements contracts. So, we have absolutely no ability to find out from our suppliers what their RGGI costs are, and they probably have no ability to be able to tell us what their RGGI costs are. We, you know, have to remind everyone that we are a regional market. And, in the regional market, all electric customers are bearing some RGGI costs in some fashion or another, if not directly through owned generation or indirectly through power purchases.

I believe -- I feel that whatever allocation method we develop, it should be consistent, it should be fair, and it should be easily monitored and easily understood.

And, as far as how we would allocate such rebate or funds to default service customers, we -- Granite State does have a annual filing in March that reconciles its power purchase costs with its retail sales.

And, I would advocate that we would include any RGGI funds that are -- that are given to Liberty Utilities to be included in that reconciliation, because that way it would be reviewed by the Commission, it would then set the rate at the same time as the change in the annual power purchase reconciliation adjustment. And, any funds that we received throughout the year can be put into an account that would earn interest that would then be given -- used as the foundation for a refund to our default service customers. That's it.

CHAIRMAN IGNATIUS: Do you have a -- would you agree that, for your power obtained through competitive bidding, that you use the ISO average emissions as a basis for RGGI costs? Or, would you not even look at that? You would simply look at the amount of default service load you have and take the -- and allocate out the amount of the RGGI pool to be distributed to your customers? Or, would you do the cost-based building up that Ms. Tillotson was talking about? Or, would you just take it on the basis of load and the amount in the RGGI fund and divvy it up?

MR. WARSHAW: The only way we would be able to do that is the basis of load, and an average emissions factor from the ISO. We have no other information that we would have available to us. Does that answer --

CHAIRMAN IGNATIUS: Well, I think, but we're ending up with I think both PSNH and the Co-op agreeing that the ISO regional average may be a useful proxy when you don't have actuals. But are we building the cost up, the way PSNH suggested or are we starting with the load as the basis for allocation? Well, you use load for allocation either way. But are you -- would you simply divide the available RGGI amounts according to default service load or would you divide the RGGI amount based on the costs that were incurred by each utility in the building up method that Ms. Tillotson laid out?

MR. WARSHAW: The issue is that, for Liberty Utilities, the only information we would have is the average -- the proxy price that PSNH was advocating. And, the only, you know, CO2 volumes that we would have would be what the ISO publishes. You know, again, it would just be a regional average. We don't have access or any information that any one supplier will provide us.

CHAIRMAN IGNATIUS: I understand that. But would you support Ms. Tillotson's approach, of studying all of the costs, given that in your case it would be a proxy from the ISO, or not even go there, and do it just on the basis of default service load, the way Mr. Dean laid out, if I'm getting people's positions right? And, if you're not sure where you come out, we can -- you can work on it through the session afterwards.

MR. WARSHAW: No. If you want to lean toward simplicity, I think Mr. Dean's approach would be the easiest. I would, you know, if we went towards Ms. Tillotson's approach, if I pronounced your name right, if not, just slap me, it would have to look at, you know, some of the additional details that would have to come in, a little on the fact that maybe we would have to also factor in, you know, the purchases that companies make to meet the RPS requirements in the state.

And, Liberty Utilities does not have any PPAs for energy to serve our default service customers. We only buy energy through an all-requirements contract.

CMSR. HARRINGTON: Just I have another question back, this is the same issue, this would be back to Public Service. I think you had stated that you sort of break yours up into two portions, one, the RGGI cost that came from the generation by your own assets, your own generation assets, and then the portion you bought from the market you would use an average thing, much like Mr. Dean said. But this is the issue I'm -- I guess I'm not quite clear on that.

Let's just deal with the average one that comes from market-based, whether it's Public Service buying it or the Co-op or whoever. They are not going to recover the full cost of their RGGI compliance and are going to rebate that back to their ratepayers, because part of the RGGI money is going to go into the RGGI fund, which ends up in the CORE fund. So, they're going to get something less the full amount. So, there's going to be a percentage of their cost they're going to recover. If embedded in their purchase, their agreement that they have to buy power, there's a certain cost of so much a megawatt-hour for RGGI on the average overall, and that's the figure I guess, that's the only one we can use, they're not going to get all of that back, because the full amount of the RGGI collected in New Hampshire is not being rebated, only a certain amount of it. I thought what you were saying, though, is, for Public Service, that you wanted all of the RGGI money back for what you self-generated.

MS. TILLOTSON: No.

CMSR. HARRINGTON: Okay. So, you're going to take a percentage of that as well. If it turns out that, and I'm making up a number, that 40 percent of the money that is collected from the ratepayers, and eventually come to the ratepayers in New Hampshire, using the average, is going to be rebated, then, in the case of Public Service, they would use that average for what they purchased in the market, but they would also apply that same 40 percent factor to what they paid for their generation?

MS. TILLOTSON: Absolutely.

CMSR. HARRINGTON: Okay. I just wanted to make sure we're clear on that.

MS. TILLOTSON: That that ratio, whatever it is, auction revenue as compared to cost, in the approach that I was advocating, and obviously didn't say it well, everybody, if it was 100 percent, everyone would get 100 percent, if it was 50 percent, everybody would get 50 percent on their cost.

CMSR. HARRINGTON: I just wanted to make sure we're clear on it. Thank you.

MS. TILLOTSON: Uh-huh.

CHAIRMAN IGNATIUS: Ms. Hollenberg.

MS. HOLLENBERG: Excuse me, if I might just follow up on your question, Commissioner Harrington. I think you touched on an important point, which is, under the averaging or using the average cost of compliance based on the ISO for market purchases, it's possible that the other utilities, and, to some extent, PSNH, will not recover their actual RGGI costs, because the average may be less than what was embedded in the cost they paid to the supplier.

CMSR. HARRINGTON: Well, could I interrupt for one second?

MS. HOLLENBERG: It's a different point that you made, I understand that. But, if I could just finish?

CMSR. HARRINGTON: Sure.

MS. HOLLENBERG: What I would say is that, and then you add in the point that you made, which is, it's possible that they're -- they're not going to get their 100 percent back anyway, because some of it is being used for RGGI. But, under PSNH's proposal, they're actually going to get their actual costs for generation for RGGI amounts paid for their own generation, which puts them at an advantage, in terms of dividing the pot up. They will be able to reflect, in their calculation of what they get from the pot, an actual number, an actual cost number to calculate towards their generation output, and an average cost number for their market purchases. Whereas the utilities, other utilities will have to use only an average. So, I just wanted to point that out as something that --

CMSR. HARRINGTON: That was my question.

MS. HOLLENBERG: Okay.

CMSR. HARRINGTON: And, what she answered, is that is not the case. That, if that percentage was -- everyone was going to get -- use the 40 percent, because the rest of the money was going to go into the CORE funding, that Ms. Tillotson just answered my question, was that their actual costs for their generation would be multiplied by 40 percent, and they would only get 40 percent of it, not the total amount. So, whether it was applied to the average or it was applied -- that they bought in the market or to self-generation, that same scaling factor would be applied. So, that was my concern, because she didn't say that initially. But, in response to my question, she would apply that same percentage, so that wouldn't be the case.

MS. HOLLENBERG: I guess my -- I guess I'm not sure if I understand maybe then. Because I think what I see is that there could be a significance to the fact that PSNH will get to use an actual cost factor to calculate what its RGGI costs are, whereas the other companies will use an average cost factor. And, I think, in that instance, for that amount of demand, I think that you are allowing PSNH to possibly recover more than you're allowing the other utilities to recover.

CMSR. HARRINGTON: Okay.

MS. HOLLENBERG: And, I don't know if I understand it correctly, but I'll talk about it.

MR. MULLEN: After --

CHAIRMAN IGNATIUS: Mr. Mullen.

MR. MULLEN: After listening to the discussion here, I'm trying to think that -- I think that, in hearing what PSNH has said and some of the others have said, I said, well, I think if each utility starts with its default service load. And, then, from that, says "okay, how much was served by a non-emitting source?" Whether it be through a PPA or whether it be through a hydro plant or whatever it is. Okay? So, then, you subtract that load from the total default service load. So, then, that leaves you with load that was served by emitting sources. So, whether you're using either the average ISO emission rate or you're using the emissions associated with PSNH's fossil plants, I think that each utility could then say "okay, for the portion of our load that was served by an emitting source, you either come up with a cost based on the average rate or, for PSNH, came up with a cost based on the actual emissions of that plant."

So, then, when you have that for each utility, you say "okay, here's the cost paid by Utility A, Utility B, Utility C, Utility D. You add them up. What are their respective percentages? So, then, when you see how much rebate -- how much was over a dollar allowance of money to be rebated, you have the percentages, and you say "okay, Utility A get X percent, Utility B gets Y percent, and I think you could maybe do it that way.

CMSR. SCOTT: Just for a point of clarification, I understand that, if you go down that road, the non-emitting sources. But there is a difference on the market, it may not be enough to make a difference, but RGGI sources are 25 megawatts and above. So, there's potential for emitting sources that are below that threshold, they're not in RGGI, however.

MR. MULLEN: Right. Now, whether that comes into, you know, how significant is that impact, that's something. And, I mean, regardless of what we do here, there's going to be inequities anyhow, because of the way the statute points us to default service customers. Well, those -- that can happen -- the customers that pay in today may not be the customers who get the money back. But that's just reality.

CMSR. SCOTT: True.

CHAIRMAN IGNATIUS: And, Mr. Mullen, do you think, having both actual, in the case of PSNH, having both actuals and the proxies, when you can't determine on, for market purchases, makes sense?

MR. MULLEN: I think so, because some of their load is served by their plants and some of their load is served by market purchases. So, there will be a mixture of both. And, similar to, say, if the Co-op has a PPA with a certain facility, that was either emitting or non-emitting, you could figure out the actuals associated that, compared to market purchases.

CHAIRMAN IGNATIUS: And, to -- is there an easy way to remove from the total default service load, for PSNH, we'll start with, to remove the other sources of power that are not emitting.

MR. MULLEN: Well, I think to PSNH's annual reconciliation docket, where they will show how much power was produced by various sources. How much came from their hydros, how much came from coal, how much came from PPAs. They know how much their PPAs are. So, I think you can -- I think you can do that calculation.

CHAIRMAN IGNATIUS: I guess that's the

piece I want to be sure I understand. We know what their entitlements are under those commitments. Do we know the actual receipt of power under those? Or, are we close enough to think that it's a sound analysis to be able to --

MR. MULLEN: Yes. And, in every month, PSNH files with us how much they've purchased either from IPPs or under PPAs with certain facilities.

CHAIRMAN IGNATIUS: Okay. Other comments? Anyone that we haven't heard from who wants to speak? Oh, Commissioner Scott, a question.

CMSR. SCOTT: Just for everybody's edification, you probably know this, the next RGGI auction is scheduled for March 13, that's the next quarterly auction. And, Jack, correct me if I'm wrong, it takes roughly, what, a week for that money to flow to the State? Is that roughly correct?

MR. RUDERMAN: A week to ten days.

CMSR. SCOTT: Okay. So, just so you understand when the money at least will be with the Treasurer of the State of New Hampshire anyways.

CHAIRMAN IGNATIUS: Any other ideas? Concerns?

(No verbal response)

CHAIRMAN IGNATIUS: Questions?

(No verbal response)

CMSR. SCOTT: And, to follow up, the current reserve price is $1.98 for RGGI. And, if my memory is not serving me well, I think the last auction, it was somewhere between 50 and 60 percent of the allowances sold. So, just to try to give people a frame of reference to --

MR. RUDERMAN: I know the absolute number, I don't know the percentage, but, roughly, a little bit over a million allowances were sold, at $1.97 I believe was the clearing price.

CHAIRMAN IGNATIUS: All right. I know that the order of notice had said that people could email comments in, rather than be here this morning. I don't believe any have been received, not as of when we pulled this this morning. So, if anything else arrives, it will be posted to the file. Mr. Epler's comments, obviously, we will accept, and they will be posted. So, if he doesn't send them out to everyone, I imagine he will, but, if he doesn't, they will be available online.

I think, in order to have some sort of closure, we ought to allow for any further written comments, whether you've already spoken to it and want to say more or, if things that come as a result of continuing to meet among yourselves, if there's any agreed on recommendations or further positions, why don't we allow for comments.

Let's say January 25th, if I have the date right, a week from tomorrow, Friday, close of business. If there's anything else, speak up?

MR. FOSSUM: I have one -- I'm sorry. I have one question, I guess. Ms. Amidon led off with a -- which I guess was a suggestion that perhaps the Commission could issue an order essentially approving an overall general methodology, and then various people could work on how exactly that would be implemented. I'd just be curious to know, to the extent that you may know today, whether that is a -- something the Commission is inclined to do or whether it would be waiting for some further something from one or more parties before issuing anything formally?

CHAIRMAN IGNATIUS: Well, my thought is, you'd want to have most of the details figured out beforehand. And, the things that I guess I was assuming she was referring to were, one company may implement it on a six-month basis, and its months are January and July, and another company might implement it on a six-month basis, and its dates are April and October. That sort of detail that would be company-specific and still to be worked out, maybe it could be six months versus quarterly versus annually. Although, I think that's maybe more in the overall methodology that we would think we would want to have settled beforehand, because of, as every one has said, consistency is a good idea. So, I guess I'm imagining, and I'm just speaking off the top of my head here, that some variant, variation among companies, and not requiring -- it would be terrible to say "everyone has to do this February 1st." If no one has a reason to be filing anything for February 1st, except we tell you you have to for this one credit, that's not efficient. So, some flexibility to work into when you're producing reconciliation materials or, you know, dates that you're calculating things from for other purposes would make sense to build on, and that varies from company to company. But that I would hope that most of the structure of the methodology would be in place. If there's an agreed upon proposal, so much the better. We'd love to see it. So, if today, and in the next few days, if there's an agreement on how to do that, or distill it down to any remaining issues that can't be agreed on, and let us come up with a decision on what to make of those, that always helps us. Ms. Amidon.

MS. AMIDON: And, you are correct. I was hoping to get, for example, I think, based on what we heard this morning, the principal issue that we have to work out is the allocation of any available RGGI excess funds, and how those are to be allocated among utilities. The statute says "on a per kilowatt-hour basis for default service customers", that's fairly straightforward. But, yes, my goal was to try to establish that methodology. And, then, insofar as rate changes occur, that would be something that each utility could inform the Commission how they would like to do it, and the Commission could review that and determine if that was acceptable. But that would avoid -- that would simplify the administrative process, both for the Commission and for the utilities, to have them be able to use one of their periodic filings to incorporate the rate change. Thank you.

CHAIRMAN IGNATIUS: Mr. Fossum.

MR. FOSSUM: Yes, that I understand. I guess my question was, as was mentioned, basically, the big issue apparently is how whatever money is available gets allocated, and there's some difference of opinion so far. And, so, that's what I had wondered about, is whether the Commission would look to see if those in the room, or whoever might file comments, could come to some agreement to recommend to the Commission, or whether, based upon what you have heard and what you'll read over the next week or so, the Commission would say "this is the allocation methodology that we would like to see companies go implement that and make it part of some periodic filing." And, that's what I was wondering.

CHAIRMAN IGNATIUS: I think our interest is, we'd love to see recommendations, if you can come to them.

MR. FOSSUM: Okay.

CHAIRMAN IGNATIUS: And, I can say, for myself, I would want the allocation methodology resolved, whatever we issue would address the allocation methodology and determine what it's going to be. And, that other smaller details about timing and which form to use, maybe that would still need to be worked out. But that something -- I think the allocation methodology is pretty fundamental. All right. Anything else?

(No verbal response)

CHAIRMAN IGNATIUS: If not, thank you for thinking about this, grappling with what, you know, as usual, a one or two sentence provision in the statute leads to hours and hours to try and sort out how it really plays out. So, thank you for that. We're adjourned.

(Whereupon the hearing ended at 11:21 a.m.)