ILLINOIS POLLUTION CONTROL BOARD

August 18, 2006

IN THE MATTER OF:)
)
PROPOSED NEW 35 ILL. ADM. CODE 225) R06-25
CONTROL OF EMISSIONS FROM LARGE) (Rulemaking-Air)
COMBUSTION SOURCES (MERCURY))

TRANSCRIPT OF PROCEEDINGS held in the above-entitled cause before Hearing Officer Marie E. Tipsord, called by the Illinois Pollution Control Board, pursuant to notice, taken before Sharon Berkery, CSR, a notary public within and for the County of Cook and State of Illinois, at the James R. Thompson Center, 100 West Randolph Street, Assembly Hall, Chicago, Illinois, on the 18th day of August, A.D., 2006, commencing at 9:00 a.m.

A P P E A R A N C E S:

ILLINOIS POLLUTION CONTROL BOARD:

Ms. Marie Tipsord, Hearing Officer

Ms. Andrea S. Moore, Board Member

Mr. G. Tanner Girard, Acting Chairman, IPCB

Mr. Anand Rao, Senior Environmental Scientist

Mr. Nicholas J. Melas, Board Member

Mr. Timothy J. Fox, Board Member

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY:

Mr. John J. Kim

Mr. Charles E. Matoesian

Mr. James Staudt

Mr. Richard Ayres

SCHIFF, HARDIN, LLP,
6600 Sears Tower
Chicago, Illinois 60606
312-258-5646
BY: MS. KATHLEEN C. BASSI
MR. STEPHEN J. BONEBRAKE
MR. SHELDON A. ZABEL

A P P E A R A N C E S (cont'd):

ENVIRONMENTAL LAW PROGRAM, CHICAGO LEGAL CLINIC
205 West Monroe Street
Fourth Floor
Chicago, Illinois 60606
312-726-2938
BY: MR. KEITH I. HARLEY,

SORBENT TECHNOLOGIES CORPORATION
1664 East Highland Road
Twinsburg, Ohio 44087
330-425-2354
BY: MR. SID NELSON, JR.

REPORTED BY: SHARON BERKERY, C.S.R.
CERTIFICATE NO. 84-4327.

HEARING OFFICER: Good morning. Welcome everyone back.

This is day five. And hopefully this is going to be a short day for us.

We are going to start with Mr. DePriest, who was sworn in yesterday. But before we do that, I'm going to formally ask on the record, because we have been discussing on and off the record, the Stubenville study.

Mr. Kim, do you have an update on where you may be, as far as being able to present something on the Stubenville study?

MR. KIM: I can describe for you the efforts we have taken thus far to obtain that. We had asked Dr. Keeler as to the status of the report.

The last word that we had from him was in the middle or late part of July, at which time he indicated the manuscript or document had been forwarded to the environmental science and technology publisher, I don't know if it's completely an online publishing entity, but it had been sent on to the publisher; and that the word he received from the publisher was that it

would be two to three weeks before it was made available online.

We have been, since that time, checking on a daily basis to see if, in fact, it had been made available. And I checked last night -- I didn't get a chance to check this morning, but as of 10:00 last night, it was not yet available.

We have asked our librarian at the Illinois EPA to contact the publisher to see if she can either get a definite publication date or, at the very least, if it's all but published and if it's in a que waiting to be published, if we could just see if we can get a draft of the document that is going to be published. Because, I'm assuming, at this point, no further changes are going to be made to the document.

So, again, I apologize for the delay. And, frankly, this is something that we really had hoped we would have had a long time ago. But based upon what Dr. Keeler told us, as of about July 15 or July 20, it was out of his hands and it was now into the publisher's hands.

And so, now we're trying to work

on the publishers to see if we can get something there. If we don't hear back from the publisher right way, then my guess is that early next week we would potentially try and contact somebody at U.S.EPA, perhaps, and Dr. Keeler's counterparts there and see if maybe we could get a draft from them.

Or we'll try again with Dr. Keeler. He's a very busy man and very difficult to reach sometimes, and, over the past week, we've had a little bit of difficulty communicating with him.

So we're going to try and -- we sent another e-mail to him and left some messages again this morning, I believe, trying to get ahold of him, asking if he knows where things are. Or, at the very least, if he knows no more changes are going to be made, if he could send us a copy so that we can make it available to you.

At this point, I think there's -- I can't imagine there's any more changes that are going to be made to this document. I think it's a done document. And the impression I'm

left with is just waiting for its turn to make it online.

But we will continue to try, and we will give you an update next Monday to let you know if it's changed over the weekend.

HEARING OFFICER: Thank you, Mr. Kim.

MR. BONEBRAKE: Can I just ask a follow-up question?

HEARING OFFICER: Absolutely.

MR. BONEBRAKE: There was also an issue, I believe, Mr. Kim, pertaining to a document that U.S.EPA had provided to Dr. Keeler. I don't recall the specifics since the passage of time, but my recollection was it was a significant number of pages of documents.

Do you know what the status on the disclosure of that document is?

MR. KIM: Yes. We asked Dr. Keeler about that.

And my understanding is -- the way he described it to me, that it is not something that he believed U.S.EPA would ever authorize him to release, because it would be an integral part of their peer review system. I don't know

if the comments contained the identities of the parties who were making the comments or if it's a blind set of comments that he received, just simply comment after comment.

But the response we got from him was that he just did not foresee a possibility that he would ever be authorized to allow that, because -- something about, based upon the understanding that he has and other people have with U.S.EPA when they perform these types of joint studies -- peer publications, U.S.EPA peer review comments. His representation to me was, they're just never made public.

I kind of pressed him a little bit on it, and -- as opposed to the Stubenville study, which I think he has said all along, he would be more than happy to have made public as soon as it's made available -- this document he seemed to indicate he would not be able to get free from the U.S.EPA in terms of authorization to release.

MR. BONEBRAKE: Does that mean, therefore, that the document, you anticipate, would not become part of the Board record in

this proceeding?

MR. KIM: Based upon my conversation with him, I think that's correct. But we're hoping that the final document itself will, obviously, be made available just as quickly as possible.

HEARING OFFICER: Thank you, Mr. Kim.

With that, I believe, Mr. DePriest, we're on Question No. 11.

MR. DePRIEST: Question No. 11. Regarding the statement on Page 9, "For units that plan to install a wet FGD system in the future for CAIR compliance, a smaller 'polishing' fabric filter could be needed in 2009 to meet the proposed Illinois Rule" and the following discussion regarding associated costs, why would a company install a fabric filter rather than inject sorbent upstream of the existing ESP, if the emissions levels of the Illinois Rule were achievable in that manner? Wouldn't that approach be far less expensive?

My answer: As discussed in the response to Question 10.a -- I'll have to go back to yesterday -- 90 percent reduction may

not be achievable with capture in the existing ESP, based on ESP size and concerns about additional particulate emissions.

HEARING OFFICER: Mr. DePriest, could you slow down?

MR. BONEBRAKE: Are people able to hear?

HEARING OFFICER: Can you hear okay out there?

MR. BONEBRAKE: Okay.

MR. DePRIEST: Where was I?

In addition, activated carbon system suppliers, to date, have been unwilling to unilaterally offer a guarantee of 90 percent removal in ESP without the addition of a baghouse.

Just adding another comment to directly answer the question, certainly, if we could do it in the ESP, it would be a heck of a lot cheaper than in the baghouse, with activated carbon injection.

HEARING OFFICER: And you are fading. Let's plug in the mic and maybe leave it out there at the edge.

Okay. Let's try that.

MR. DePRIEST: Question No. 12. Regarding the statement on Page 10, "The owners of the Illinois coal-fired units have reached the conclusion that they will not be able to meet the requirements of the proposed Illinois mercury with activated carbon injection alone, at most units, based on the lack of precipitator margin."

Have the owners of these plants performed any tests of sorbent to base their opinions? If not, with the federal and state regulations on the way, why not?

My answer: Testing of activated carbon injection upstream of existing ESPs has been performed on a significant number of units in the industry. This testing is the basis for our concerns about the capability of all ESPs to be capable of 90 percent mercury capture without an adverse opacity or particulate emissions or both.

S&L was not directly involved in the testing, and therefore, does not have the ability to share the specifics, although this

information is probably available from the funding parties.

HEARING OFFICER: Mr. Kim.

MR. KIM: Yes.

When you say the owners of the Illinois coal-fired units, can you be more definitive as to which owners you're referring to?

MR. DePRIEST: The owners that we worked for?

MR. KIM: Well, whatever owners you were referring to in that statement.

MR. DePRIEST: I guess it would be the companies -- the units associated with the companies of Midwest Gen, Dominion and Ameren.

MR. KIM: Thank you.

MR. DePRIEST: Question No. 13. What analysis of their ESPs have the companies performed to reach their conclusion?

And, with that, I need to refer you back to my answer to Question No. 6, to be consistent. And my answer to that was, in general, our analysis of the capabilities of the existing ESPs to accommodate activated carbon

injection was performed on a qualitative basis, considering the existing ESP size and the current emission rates and opacity.

More importantly, any particulate increase in the inlet loading of the ESP will result in an increase in the outlet mode, which will impact the emission rate and the opacity.

Question No. 14. Regarding the statement on Page 10, "In addition, suppliers of the activated carbon technology are currently not willing to guarantee 90 percent mercury removal with activated carbon injection alone." Has your client performed any testing with any company to potentially provide guarantees?

Again, I need to refer back to Question No. 12, which I just answered, with the added caveat of: We are aware of test results obtained in the industry that clearly support the conclusion that a 90 percent mercury reduction cannot be obtained in all the ESP's in the Illinois units with activated carbon injection alone without adverse effects on opacity or particulate emissions or both. In our discussions with companies that provide

mercury reduction technologies, they concur with these conclusions, and in fact, will not provide unilateral guarantees of 90 percent reduction for ACI with ESP applications.

HEARING OFFICER: Mr. Bonebrake.

MR. RAO: I have a comment.

HEARING OFFICER: Okay. Go ahead.

MR. RAO: Mr. DePriest, do you have the list of the names of these companies that you got this information from, about not providing the guarantees?

MR. DePRIEST: Yes, I can offer those names. Most prominently is the ADA-ES. But second tier companies would be like Babcox & Wilcox, Wheel Grater, Destex -- equipment suppliers that would attach an activated carbon injection system to their system and then pass the guarantees through to the ultimate owner.

MR. RAO: Thank you.

HEARING OFFICER: Mr. Nelson.

MR. NELSON: Are you aware that Sorbent Technologies has guaranteed --

HEARING OFFICER: Excuse me, Mr. Nelson, you need to identify yourself for

the court reporter.

MR. NELSON: I'm sorry.

I'm Sid Nelson, Sorbent Technologies.

Are you aware that Sorbent Technologies has guaranteed 90 percent?

MR. DePRIEST: I've heard rumors to that effect. Sorbent Technologies has not approached Sargent & Lundy with such guarantees that I am aware of.

MR. NELSON: Has Sargent & Lundy ever required it from Sorbent Technologies?

MR. DePRIEST: We, typically, would be looking for the guarantees to come from the equipment supplier, either via, C, fabric filter, dry scrubber, wet scrubber supplier, who would then attach a sorbent injection technology to their offering and then give us the guarantees to pass through from the designer of the activated carbon injection system.

MR. NELSON: In the case where the material itself is sorbent, is critical to achieving 90 percent or not and where the guarantee could provide more sorbent, for

example, as to a guarantee of a certain rate, would it not make sense to put a guarantee upon the sorbent supplier?

MR. DePRIEST: In our opinion, we -- it may make sense in some cases, and maybe, in particular, when dealing with an existing ESP and that all you're purchasing is an injection system of the sorbent. But when we're purchasing a much larger piece of equipment that might be doing some of the mercury reduction itself, we would prefer to have that company, who has a lot more skin in the game, so to speak, to be a party to that guarantee.

So the guarantee becomes much more meaningful if we have a $100 million FGD contract attached to that guarantee than a $1 million activated carbon injection system attached to that, if you understand what I mean.

MR. NELSON: That's why a guarantee is so difficult for wet scrubbers, for example. But for the installation simply of only an activated carbon injection system, does it make sense for the equipment supplier that has no control over the actual sorbents that are used,

to guarantee the 90 percent?

MR. DePRIEST: We want them to have control over the sorbents that are used, because we want the guarantee to come from them. So it's incumbent upon them to research the available sorbents in the industry, including yours, find the one that's most appropriate for the application that we are asking for it to be applied to and pass that guarantee to us.

MR. NELSON: So, in your contracts, you would recommend the long-term sorbent supply contract be part of any activated carbon injection system installation?

MR. DePRIEST: It might have some attractive features to it, but, to date, we have not found a way to make that happen, to attach a long-term sorbent injection supply contract to the supply of the original equipment. It might be good to do that, but I think most utilities would like to have the ability to shop the sorbent down the road.

Let's say, five or ten years from now a new sorbent appears on the scene that maybe is not yours, Mr. Nelson, and the company

would like the flexibility to jump over to that if it made sense. So the long-term contract for sorbent has its pluses and minuses.

MR. NELSON: But if there is going to be flexibility, which might be very good, how would you expect the equipment supplier, the injection system to guarantee 90 percent if there is no long-term contract with the sorbent?

MR. DePRIEST: Well, you have to understand that the guarantees -- the typical guarantees are the ones that I'm familiar with -- the actual performance of that injection system is demonstrated in a very short period of time. That guy's paid, he's gone, his responsibilities are done.

It's now the owner's responsibility to operate and maintain that equipment to achieve the requirements of whatever his permit might be. The equipment supplier is no longer involved with that.

MR. NELSON: Thank you.

HEARING OFFICER: Mr. Harley has a follow-up.

Go ahead, Mr. Harley.

MR. HARLEY: For the record, Keith Harley, on behalf of Environment Illinois. Good morning.

You used a phrase that I didn't understand. You said you'd prefer to obtain a guarantee from a vendor which has, you said, a lot more something in the game. What was that phrase?

MR. DePRIEST: I probably shouldn't have said that -- who has a lot more investment, capital investment, let's say, in the project. So if you look at guarantees and how they're typically structured, the remedies that an equipment supplier might have available to him will be a function of his contract talks.

So, in many cases, limits of his liability will be a function of that contract cost. So if I get a guarantee from someone who has $100 million scrubber project attached to that guarantee, I have a lot more security with him, than somebody who has got a million dollar injection system.

MR. HARLEY: So is it your testimony that there are no guarantees available? Or is

it your testimony that Sargent & Lundy has made a business decision that expresses certain preferences as to what a guarantee should be?

MR. DePRIEST: I'm not sure I understand that. I mean, we try to structure our guarantees, both performance and technical and commercial, to protect the owner from his investment, protecting the investment that he's making, that technology. So I'm not sure where you're going.

MR. HARLEY: May there be -- strike that.

Could guarantees be available that would not meet Sargent & Lundy's criteria for what constitutes an effective guarantee --

MR. DePRIEST: Well, I mean, what an effective guarantee is, is the guarantee that we can get. And we, many times, ask for a guarantee that's in excess of what we are able to obtain.

And we negotiate to come up with an agreeable guarantee based on that -- under those conditions.

MR. HARLEY: Thank you.

HEARING OFFICER: Mr. Nelson.

MR. NELSON: In the case of a scrubber that doesn't exist, it takes two years to build -- to design, build and operate. Would you say that guarantees of performance are very important to the utility who buys them?

MR. DePRIEST: Absolutely.

MR. NELSON: With respect to activated carbon injection, is it possible to run a short-term trial, with a mobile unit to inject at the site, with the coal that the utility is currently burning on the existing ESP, and very inexpensively, find out if you can get 90 percent at what injection rate at that site?

MR. DePRIEST: Under those typically static conditions, I think that's achievable.

MR. NELSON: And, in fact, aren't utilities across the country today having these couple-week trials of activated carbon injection into their existing ESPs to see what is achievable at their actual plants?

MR. DePRIEST: Yes, I think you're correct.

MR. NELSON: Would it be very simple

and inexpensive then for power plants that are concerned about achieving 90 percent mercury removal to actually do these short-term trials at their plants to see if, in fact, can we get 90 percent -- can 90 percent be guaranteed at this plant?

MR. DePRIEST: That's correct. I think --

MR. NELSON: And you can't do something like that with a scrubber or SCR; can you?

MR. DePRIEST: With a scrubber and SCR -- of course, we've got plenty of them to look at that are operating out there in the real world that -- that form the basis of our establishing the comfort level with the guarantees that we --

MR. NELSON: But to achieve 98 percent SO2 removal and 97 percent?

MR. DePRIEST: Uh-huh.

MR. NELSON: Thank you.

HEARING OFFICER: Mr. Bonebrake.

MR. BONEBRAKE: Mr. DePriest, I think I did have a couple of follow-up questions for

you. Mr. Nelson was just asking about the potential for two-week trials of similar short-term tests.

MR. DePRIEST: Right.

MR. BONEBRAKE: Would the results of a short-term test like that tell you definitely whether the unit could achieve long-term compliance with the mercury standard?

MR. DePRIEST: Certainly, if you could first step in and establish a comfort level with the technology, as with any emerging technology, a long-term operation along with a term of the more comfort that you get with the technology -- and I think, currently, where we are, at least Sargent & Lundy in our opinion, is that there is not enough long-term operating experience with activated carbon upstream of ESPs and other components in the industry, to feel very comfortable about the guarantees that we might receive.

MR. BONEBRAKE: Moving to a somewhat different note, there's been a lot of discussion in the last couple of days regarding the availability of mercury reduction guarantees.

And so let me ask you, Mr. DePriest, are you aware of instances where generating companies have obtained mercury emission reduction guarantees?

MR. DePRIEST: Yes, I am. Based on some of the questions asked yesterday, I decided I'd go back to the office and do a little research into some of the specifics of the projects that we're involved in.

And there's three instances that I can bring to bear here today where we have actually secured guarantees for mercury reduction on full scale utility coal-fire power plants. And I'll just briefly go through those three.

One. The first example would be a large 800-class megawatt super critical unit that we're currently in design with that we have secured as part of our contract for the pollution control equipment on that site, a 50 percent mercury reduction guarantee on a fabric filter with a dry FGD system in front of it, using PRB coal with the maximum limitation of ten pounds per million ACFM inlet activated

carbon injection rate with the remedies being -- well, I'll first go into the permits that the particular station has.

HEARING OFFICER: Excuse me. I hate to interrupt, but I want to be sure that we're not -- as has been said many times -- mixing apples and oranges.

MR. DePRIEST: Okay.

HEARING OFFICER: Fifty percent emission reduction from what, from what's currently emitted?

MR. DePRIEST: It's a brand new unit.

HEARING OFFICER: Okay.

MR. DePRIEST: From the coal.

HEARING OFFICER: Thank you.

MR. DePRIEST: From the coal. All of them are oxidized or unoxidized.

HEARING OFFICER: Thank you.

MR. DePRIEST: It's a 50 percent reduction.

HEARING OFFICER: Thank you. I just wanted to be sure.

MR. DePRIEST: The permit that the utility is working to has a mercury emission

limit of 2.72 pounds per trillion ETU. So, depending on the fuel that they burn and the mercury level in the fuel, that could result in any number of different percent reduction requirements to achieve the permit level.

But the permit level has a caveat attached to it. It says that we -- part of your permit will be to take that activated carbon injection system that you bought from your system supplier at 10 pounds per million ACFM and show us the best it can do.

And they have agreed to modify the 2.72 pounds per trillion emission limit based on that testing activity. And the remedies that the equipment supplier has is that he's guaranteed he'll do at least 50.

I'm sure he'll probably do better than that, considering the type of technology we're talking about and the status of the activated carbon available in the industry. But that's the guarantee we got, 50 percent reduction in that particular project, new units.

HEARING OFFICER: Mr. DePriest, excuse me. I'm assuming you can't tell us who that is,

but could you tell us please where that plant is?

MR. DePRIEST: It's in North America.

No, it's in the state of Iowa.

HEARING OFFICER: Thank you.

MR. KIM: And just for clarification, that's a unit that's in design. So it has not actually been built?

MR. DePRIEST: That's correct.

Example No. 2 is, we recently bought five wet FGD systems, limestone based, for a utility here in the Midwest. Assisted them in buying it, I should say, they bought the system.

We obtained from the system supplier -- this is a wet limestone scrubber, all of which would be installed, retrofitted to existing plants, downstream of cold-side ESPs. We got a 90 percent mercury reduction guarantee from the FGD system supplier, that he would capture that in his scrubber himself.

So the precipitator gets something, that's neither here nor there. He's going to get 90 on his system, inlet to outlet.

With the remedy, if it doesn't work, he has the ability to go in and add fuel additives to the furnace to change the speciation of the mercury -- oh, I'll make one more caveat before I move on. Just to be sure we're clear, it's 90 percent reduction of the oxidized mercury coming to it.

So he has the ability to add additives to the scrubber in case he has a reintrainment-type or reemission-type of issue to secure that guarantee or add additives to the fuel. The case of adding additives to the fuel, that would be done at the expense of the owner who is trying to enhance the oxidized portions, so that the scrubber works harder.

If the system does not work, the remedy is for the system supplier to supply the owner with an activated carbon injection system upstream of the existing cold-side ESP and get what you got. So if he gets ten percent, he's clean, he's done.

If he gets 90 percent, everybody's happy and he's done. That's Example No. 2.

The third example -- and these are

only three examples where we have, actually, a firm guarantee for mercury reduction. We help to assist another client to purchase a fabric filter with the intent of, in the future, adding a dry scrubber, but currently, just the fabric filter, to a coal-fired unit burning PRB.

We asked for 90 percent reduction, total mercury reduction, they countered with 75, and that's what we ended up signing the contract at. Seventy-five percent mercury reduction, activated carbon injection, upstream of a new fabric filter, which will operate downstream of that existing ESP. Those are three guarantees that we have secured.

Now, the question came up, well, how about securing guarantees associated with activated carbon injection upstream of an ESP. We have had an opportunity -- and I would clarify my comments yesterday, that I think might have misled some people.

We have not had an opportunity to actually ask for such a guarantee formally in a contract-type of offering, but we have interviewed activated carbon injection system

suppliers as to their willingness to offer such a guarantee. And the example that was presented to us was a project where the company had actually injected activated carbon into a unit that had an ESP of over 400 SEA, did not use SO3 conditioning for particulate collections, had a very long, in excess, of 100 foot leading up to cold-side ESP.

Under those conditions and those caveats, we were told that he would be willing to offer a 90 percent reduction guarantee for that type of situation. We made it very clear, you take away any of those caveats, SEA less than 400, SO3 injection for particulate control or not a robust inlet ductwork, all bets are off. But under those conditions, based on his testing results, he was willing to up for that guarantee.

Now, maybe in the future we'll have a reason to formally ask him for that. And then we'll see whether or not he'll back that up with an actual formal guarantee, but that's what's been offered.

So to clarify my responses

yesterday, hopefully that does that.

MR. BONEBRAKE: One other follow-up. The guarantees that you've described, Mr. DePriest, are they a guarantee of long-term compliance with a particular standard, or do they address achievement of a particular standard at a particular point in time?

MR. DePRIEST: They are, for all practical purposes, a one-time test-type of guarantee. You set the system up to run under a certain set of conditions that meet the criteria of the contract, you test it, it meets 90 or it doesn't meet 90. It meets 75, he's done, doesn't meet 75 -- if it passes, he's done.

And now it's the responsibility of the utility to take that and make it to operate for the rest of the life of the plan under his own.

MR. KIM: Two follow-up questions.

The first: In your second example, of your list of three guarantees that you went back and reviewed, and maybe I missed this, but can you specify the coal type that you anticipated for that system and capacity of

that? I don't have that.

I know the first one you said was a PRB 800 megawatts, but -- and I think you identified the second and the third. But do you have that information from the second example?

MR. DePRIEST: We certainly did, in the contract, specify the fuels that we are going to be burning in those units. And it's a bit of a mixture, in that this particular utility blends PRB with bituminous coal for purposes of carrying a load on certain hot summer days.

And so the guarantees are structured to accommodate either a full PRB or a blend of PRB with other higher octane fuels, like bituminous coals or petroleum, coke, et cetera.

MR. KIM: Do you recall the capacity for that system?

MR. DePRIEST: These are --

MR. KIM: Or is this more than one system?

MR. DePRIEST: These units range in size from 400 megawatts to 700 megawatts,

approximately 680, I think, something like that.

MR. KIM: The other question that I had -- and this goes back a little bit, I think, to something that Mr. Nelson might have been getting at. Understanding -- and I guess for now, setting aside the comfort level you might get with a long-term test versus short-term test -- isn't it possible that even if you do, what is, I guess, being referred to now as a short-term test, that those results might, in fact, be consistent with what you would see at the end of a long-term test?

In other words, just because you don't have a long-term test does not necessarily mean that the short-term test is not going to be ultimately correct, as far as what the results would be in a full scale operation; is that correct?

MR. DePRIEST: I think you could say that.

There's a possibility that, at the end of the first year of operation, that you may test again and get the same results.

MR. KIM: Sure.

MR. DePRIEST: Certainly that's a possibility. And, I guess, if you think about the comfort issue that you mentioned, if I was asked that question on a who gets the sulfurization system or electric precipitator or fabric filter or even an SCR that is relatively new to the business today, is that how comfortable are you with the guy who made the guarantee on day one and also made the guarantee at day 365? I feel very comfortable that that guy is going to be able to do it, because we know the system as well as he does.

In the case of this particular unit, you know, we're in the learning phase. And we need, you know, some experience in order to feel comfortable.

HEARING OFFICER: Dr. Girard.

MR. GIRARD: Can I follow up on that?

Mr. DePriest, in relation to these guarantees that you actually have knowledge of, the way I understand it is, once the plant is up and running and it demonstrates that it meets the performance targets, then the vendor has satisfied the guarantee requirements. And then,

long-term, it's the owner's responsibility to move these targets; is that correct?

MR. DePRIEST: That's correct.

MR. GIRARD: So, typically, how long do they have to demonstrate this compliance with the guaranteed limits? Do they, typically, run for a year, two years, three years, or is it operational for two weeks or a month?

MR. DePRIEST: It's a bit of a commercial -- I guess, the question is how you structure that guarantee. But usually a system supplier will want to get paid when he's done meeting his guarantees, maybe some retention, ten percent of his contract.

And holding that for one year, two years, three years, costs everybody money. The equipment supplier as well as the owner, because the guy jacks up his price to accommodate the fact that he's not going to get paid for two or three years after he has supplied the equipment.

So it's a bit of a negotiation. I'd say, typically, in the past, that guarantee is performed within the first 90 days of operation of the unit, demonstrated and then

paid, and the vendor would go away.

It doesn't keep you from negotiating a contract that says, I want that guarantee to be tested in the first 90 days, and I'm not going to pay you your money until a year later when I test again. So you can structure a guarantee, you know, any way you want, it's a matter of how much you want to pay for that guarantee.

MR. GIRARD: But in terms of these three contracts you went and looked at last night in your office that involve guarantees, are they more in the typical range?

MR. DePRIEST: They are more in the one time -- first 90 days, test it, if it works, the vendor gets paid. And the onus is on the to operator to continue to operate it in the fashion that it was operated in during those 90 days.

And 90 days is a bit of a guess, it could be 60 days, depending on the contract. And 60 days from maybe substantial completion of erection or 60 days from the first commercial operation.

There's a number of different dates that you could use to start the clock ticking, but it would be fairly short.

MR. GIRARD: Thank you.

MR. RAO: So, typically, whether the project is a two hundred, $300 million dollars FGD or a $1 million sorbent technology, it's still the same way, getting the supply in a 60 to 90-day period where they do the testing and show compliance?

MR. DePRIEST: That would be, typically, the case.

In a big scrubber system today, I think we've kind of moved in the industry over to a multiple test kind of concept. And what we're looking at is not necessarily to demonstrate that the system is capable of meeting the 98 percent SO2 removal, but we want to be sure that all the hardware that the guy supplied, all the pumps and mixers and valves and instruments are still working a year later.

It's more of a warranty issue more than a performance issue, in that the quality of the materials and workmanship supplied, we want

that demonstrated over a longer period of time. More than -- you know, because of the significant size of the investment.

MR. RAO: Compliance is just one part of the --

MR. DePRIEST: Yeah, compliance is just one part.

MR. RAO: Thank you.

MS. MOORE: Earlier I heard you say that it might just take one test within those 90 days for them to meet that compliance and then they're gone?

MR. DePRIEST: Uh-huh.

MS. MOORE: So if they had, you know, 30 runs that they tested day after day and it wasn't good, then day number 31 they meet their compliance, now they're gone.

MR. DePRIEST: That's a good point.

We'll establish what tests count. Where they say, okay, you guys can go in there and tune your system, tweek it, do whatever needs to be done to get yourself in a position where you're comfortable that you will pass the test and advise us when you're ready to test.

When we test, if it doesn't make it, that test counts.

But all the tests that he did up to that point, where he might have been changing operating conditions or trying to find the right spot in the run-in, he doesn't have to pass those, necessarily. We understand that it may take --

MS. MOORE: He just needs one.

MR. DePRIEST: Right.

MR. GIRARD: Well, let me follow up on that. In terms of continuous emission monitoring equipment, where you want to make sure it works for a long period of time, typically, how long are the test runs before they meet their guarantee?

Or is it a warranty situation where they -- it's warranty'd for a couple of years or something?

MR. DePRIEST: Well, a typical performance test may take -- and depending on the involvement of it, if it's on a -- let's say we're injecting upstream of an existing cold-side ESP, we're probably going to want to

have some particulate testing done, some opacity testing done, as well as the mercury testing done. So he can demonstrate that he can simultaneously meet all of those guarantees at once.

It would just be mercury reduction. It would be mercury reduction with no adverse impacts on other things that he'll have to test.

It might take him four, five days. Depending on the size of the unit and the availability of test ports and things like that, the accessibility and how difficult it might be to test.

And then, of course, the boiler has got to be operating right, there's going to be ups and downs, starts and stops. But once you get going, a typical test, three, four days.

MR. GIRARD: Thank you.

HEARING OFFICER: Mr. Nelson, thank you for your patience.

MR. NELSON: I think there may be a misconception. Do you anticipate, in an activated carbon ESP guarantee situation, that

the vendor would get ten tries to meet the guarantee?

MR. DePRIEST: Typically, not.

MR. NELSON: Okay.

MR. DePRIEST: No, we would expect -- we would certainly give the vendor all the time he needs to come in and manipulate the equipment that he supplied to find the right spot to run, so he can meet his guarantees, within reason. The guy has got to run his power plant.

And he'll give the supplier an opportunity to make it work. And then when he's comfortable that it will work, he'll say, okay, now we are going to run the test.

MR. NELSON: The guarantees that I've seen -- do the guarantees that you see typically state very clearly under what conditions the guarantee is to be met? For example, the load of the plant, the length of the test, the coal to be burned. It's usually very specifically spelled out; is it not?

MR. DePRIEST: That's true.

MR. NELSON: And it's usually at full load; is it not?

MR. DePRIEST: We would usually structure a performance test to be able to meet compliance at the various loads, if we felt that was important to the particular technology. Some technology is not so important.

MR. NELSON: With activated carbon injection, does the resident time of the sorbent change, when you're a full load or at night, when you go down to half load, for example. Do you expect better performance or worse performance?

MR. DePRIEST: You would expect -- with sorbent injection technology, you would expect better performances.

MR. NELSON: So in long-term operations, the plant goes up and down, you would expect an average of better performance during a short-term test at full load; is that correct?

MR. DePRIEST: In aggregate, you probably would. It's depending on how you look at, percent reduction or pounds of mercury captured or how you define better performance.

HEARING OFFICER: Ms. Bassi.

MS. BASSI: I have just one follow-up. In your second example, where you describe the five wet FGD limestone-based FGDs and then a number of activities that a vendor or equipment supplier would perform if it did not remove 90 percent oxidized mercury, would the company have to pay a premium, of sorts, to get that kind of a guarantee?

MR. DePRIEST: Well, certainly, any guarantee that you get costs money. If you didn't ask for guarantees, you get a better price with no risk.

So the more stringent the guarantees, the more, I guess, restrictive the remedies that you might put in the guarantee language as to how you might fix this problem, and the extent to which you expect him to expose his contract value to remedies will all affect the price of the contract and the cost of the guarantee.

HEARING OFFICER: Mr. Harley first and then Mr. Nelson.

MR. HARLEY: Is it your testimony that tuning the system following the installation of

equipment is, typically, a 60 to 90-day process?

MR. DePRIEST: Well, it's very much dependent on the complexity of what you're tuning.

MR. HARLEY: What if you were tuning an ACI upstream on the cold-side ESP?

MR. DePRIEST: Well, I wish I had 30 or 40 of them that I could refer to to know just how long it might take. But I think it's something we're still learning.

I don't expect that to be a particularly difficult tuning operation. But there are not a whole lot of them running that we can point to to say it's going to take so long.

MR. HARLEY: Would it take, in your opinion, best guess, 60 to 90 days?

MR. DePRIEST: I would certainly think we would be able to do it in that, yes.

MR. NELSON: And in terms of then subsequently testing over a range of conditions or key parameters, you said that testing could be completed in four to five days?

MR. DePRIEST: Sure.

MR. HARLEY: Are you familiar with the compliance phase, which is contained in the proposed rule for coal-fired electric generating units to meet the requirements of mercury reduction?

MR. DePRIEST: I believe it's July '09.

MR. HARLEY: So almost three years?

MR. DePRIEST: Correct.

MR. HARLEY: Thank you.

HEARING OFFICER: Mr. Nelson.

MR. NELSON: With respect to sorbent injection into ESPs, the guarantees that you would seek for your clients, I'm going to say, a certain removal rate at a certain sorbent consumption or sorbent injection?

MR. DePRIEST: They may, or we may allow that to flow. We may ask for a guarantee of such and such reduction and you tell us how many you need. And we'll evaluate that versus the other proposals we get.

MR. NELSON: So, in other words, in a process where the performance is usually directly proportional to the sorbent consumption

rate, you can always go to increasing the consumption rate to achieve the removal?

MR. DePRIEST: If you've got a system that's capable of catching that additional sorbent that you've injected, yes.

MR. NELSON: Okay.

MR. DePRIEST: That's part of our evaluation of a guarantee like that, it would be a function of how much the particular supplier says he needs to achieve that guarantee.

HEARING OFFICER: Ms. Bassi.

MS. BASSI: Mr. DePriest, what do you mean by catching that additional sorbent?

MR. DePRIEST: Well, any sorbent you inject -- if we're talking sorbent injection technologies, which I guess we are -- needs to be captured in a particulate control device, either the bag house or the ESP.

MS. BASSI: Thank you.

HEARING OFFICER: I think we are ready for Question 15.

MR. DePRIEST: Mr. Chicanowicz has testified that, "Guarantees in an environmental control technology provide only partial

compensation for shortcomings and are not significant factors in the decision to adopt any particular technology." Do you agree with this statement?

My answer is, I agree with the guarantee -- that guarantees may provide only partial compensation. But I disagree about the impact of guarantees and their decision to adopt a particular technology.

A prudent company will not make a significant investment or rely on a particular technology to meet regulations for continued operation without the assurance of a guarantee. And I guess I'll go on to say that that's just one component of the evaluation factors that we use to pick something.

We feel like the guarantees protect -- really protect the owner from the investment he's making in that particular technology. It doesn't protect him from the ability -- consequential issues of not being able to operate his power plant.

We can't get the technology supplier to get behind that particular risk,

that's something the owner never is able to sell to somebody else. So guarantees are important, because we want the guy's attention, but they're not the only thing.

HEARING OFFICER: Question 16.

MR. DePRIEST: No. 16, regarding your statements beginning on Page 11, Capabilities of the Existing Electrostatic Precipitator to Capture Mercury-Specific Sorbents Without Exceeding the Particulate Emission Limitations of the Plant, and specifically, "Consequently, very little, if any, margin typically exists beyond this design criteria to accommodate the addition and capture of mercury-specific sorbents."

Please provide all calculations and any test results for ESPs in question that form the basis of your stated opinion, including, A, any CFD flow modeling of the ESPs, B, Calculations of sorbent injection rates fly ash mass flow rates and capture rates of sorbent and fly ash in the ESPs. Please be prepared to go through these calculations in detail for at least one example, and C, Any test results of

sorbent injection tests performed on the specific Illinois power plant ESPs in question.

And the answer, please refer to my answers to Questions 6 and 14. I could reread them, if necessary.

And then I go on to say, we are not aware of any specific tests done on Illinois units. So this is a specific test done upstream of existing ESPs.

However, based on our extensive experience working with these units, these specific units in the state of Illinois and others of their vintage, and in some cases as the original equipment designer, we understand that many of the units have little precipitator margin.

HEARING OFFICER: I have a question when you say "we understand." Is that based on information from the companies or based on your own expertise?

MR. DePRIEST: It's based on our own qualitative analysis that we did looking at many, if not probably 90 percent, of them. I'd have to look at the numbers.

We were actually the original design engineer on the ESPs in question.

HEARING OFFICER: Thank you.

Mr. Bonebrake.

MR. BONEBRAKE: And, Mr. DePriest, just for clarification, your statement, I think this is consistent with what you said in response to Question No. 6, that cited in Question No. 16, your particular statement is based upon the qualitative analysis that you referenced earlier rather than the particular calculations; is that correct?

MR. DePRIEST: That's correct. The conclusions that we've drawn are not based on calculations that we've performed, but based more on the qualitative assessment of the arrangement of the equipment at the site, the size of the precipitators, the current emission limits and opacity levels, and then looking at what would happen qualitatively if you put a bunch of sorbent into that same particular controlled device and asked it to perform at that same level.

So our analysis is not based on

calculations but based on more of a qualitative nature and our knowledge of the equipment in question.

HEARING OFFICER: Would it be safe to say, Mr. DePriest, and please forgive me if I'm mischaracterizing this, but I'm trying to get this in the simplest of terms. A lot of your testimony, where we're asking for specific details about how you did this, basically was put together by you and/or your company looking at your clients, your contracts and what you've done in the past and then taking that information and looking at the requirements of the rule and saying, generally, or -- and you keep saying qualitative analysis, but...

MR. DePRIEST: Right.

HEARING OFFICER: You did not specifically sit down with -- and let's make up, XYZ company who has been your client for 45 years and you've built their facilities and say, okay, if XYZ has to meet this 90 percent reduction, this is exactly what they would have to do?

MR. DePRIEST: I think this question

might come up later but, I guess, to answer your question now, the way we assisted the clients in question here is, they asked us to look at -- specifically look at each and every one of their coal-fired units in their system. And we identify -- we did do that.

We sent a team of engineers to every site. And with that team of engineers, they went to the site and they looked at if we installed an activated carbon injection system upstream of the existing ESP, what would that cost and what would it look like? If we had to install a fabric filter on that site, what would that look like, ductwork arrangements, accommodations for draft system modifications, ox power system modifications arrangement at the site, and the cost to do all that.

What would it look like to add a wet FGD system to each one of these sites. We, essentially, established a database of cost, both capital and O&M, to the application of different technologies at each of these stations and we also made a judgment as to how they would perform from a mercury standpoint.

And we told all that to our client -- the clients, and they took that information and internally made a -- came up with a strategy on how they might achieve either the CAMR requirements, the CAIR requirements or now the Illinois mercury requirements. And how those might fit together if they were happening at different times, so sequentially.

So we, essentially, provided them with all the data that they needed to make an analysis. We didn't do the analysis for them.

I think that's part of the reason why I made that statement at the beginning is that we -- their strategic plan was, for the most part, performed and developed by them, they sent information we gave them.

MR. GIRARD: Mr. LePriest, in relation to the existing ESPs that you must have thought about in coming up with the answer to this, I mean, what is a typical margin that exists beyond the design criteria? I mean, what's the ballpark margin that you're sort of keeping your head as an engineer?

MR. DePRIEST: That's a very good

question. I think, if you'd look at these (indicating), and it's a bit complicated in this situation, because these units in the state of Illinois, for the most part, maybe even in all cases, were designed to burn high sulphur Illinois basin coals -- high, meaning sulphur.

Most of them have been converted, and they were designed with certain margin deflect particulate based on that fuel. They've since been changed to, for the most part, to PRB coals, much lower sulphur, much more difficult to collect ash.

Any margin that we might have had in there, in most cases, was consumed, to the point where the utility had it go in and actually artificially add SO3 or some other conditioning agent to the flue gas in order to meet the performance that they're required to me by permit.

So we design then with a certain margin, initially, on high sulphur coal, they were switched to low sulphur coal, the margin went out the window. They came back with an ash conditioning system to try to cover that margin,

and successfully, I would say.

There are some plants, better than others, with more margin in it than others. But all now are operating within their permit levels.

And I haven't answered your question about the actual degree or percent of margin. I guess, with the current -- I'm trying to think of which way to look at this.

I guess from an opacity standpoint, you think of the Ameren units in the state of Illinois, they have to meet a 30-percent opacity limit on their stations. They operate up to the neighborhood of 25.

So if that's any indication of margin, even though you have to know the slope of the curve as you increase particulate loading, how that affects opacity, and that's a complicated curve, depending on the people with the ash that you're actually looking at with your opacity meter. But we think that's pretty darn close, it's kind of getting marginal.

You have a 25 percent opacity and you've got a 30 percent limit. And you're

talking about adding more particulates on the front end of that precipitator.

So we made a judgment as to how much we felt the guy could get with mercury control, and it wasn't 90 percent, in our opinion, on those units.

MS. BASSI: How about particulate matter removal?

MR. DePRIEST: The particulate matter removal is, I guess, another story. Most of these plants also have a particulate emission -- an actual mass in emission rate limitation that they have to meet.

And that is different on every station. I currently don't have that information in front of me to know what that would be.

But we do recognize that any addition of particulate, at least in our opinion, has the very real possibility of increasing the outlet loading. The degree of margin that they have between their permit limit and their actual operation, I'd have to go back and look at the data, I don't recollect that

right now.

HEARING OFFICER: Mr. Kim first and then --

MR. KIM: Yes. Going back -- and just to clarify, I think I know the answer.

But when you made reference to a group of your company's people going out and doing a plant by plant analysis of their specifics and configurations and so forth, the result of that information that was prepared -- and, you know, I think you said you prepared the data -- you didn't, necessarily, do the analysis, but you prepared the data so that the companies themselves could do the analysis. I don't want to put words in your mouth, but that's what I got from --

MR. DePRIEST: Yes. Just to clarify it further, to be totally honest here, we did that type of analysis for two of the utilities in question. The third utility, we actually assisted them in finding a strategy.

MR. KIM: Well, okay. My first question was, is that information included within the umbrella of information that you had

identified earlier on in the hearing as being proprietary and therefore not something you were able to share with the Pollution Control Board?

MR. DePRIEST: That's correct. Even though -- since yesterday's discussion, I remembered that my testimony actually does include three examples of three different proprietaries in the state of Illinois, where the utility told us that we could go ahead and share the information on costs with the Board.

And I've included that in my testimony, three specific examples on all that we've done, that they felt were, apparently, okay to talk about.

MR. KIM: And when you said that there were two utilities that you prepared that type of analysis for and the third that you assisted them, can you identify which two you did the analysis work for and the third that you assisted in the analysis?

MR. BONEBRAKE: And I think you're mischaracterizing --

MR. KIM: And if I am, I apologize.

MR. BONEBRAKE: Because -- to clarify.

I think you're suggesting that Sargent & Lundy did two CAMR assessments for a couple of companies. And I don't think that's what he said, Mr. Kim, so maybe you can clarify.

MR. KIM: Yeah, please do. If I misstated that, I apologize.

MR. DePRIEST: If he said that, we didn't do that.

MR. KIM: Okay.

MR. DePRIEST: We developed the data and capital and O&M costs and performance expectations for all the units in the system for the application of a number of different technologies. And then we gave that to the owner and he took that information and developed his own strategy.

MR. KIM: Okay.

MR. DePRIEST: We did not develop -- two cases, we did not develop the strategy. The third case, we actually did that part, as well as helped them develop the strategy.

MR. KIM: And I guess that's what I was getting at. Can you identify, when you say them and those two --

MR. DePRIEST: Ameren is the one that we helped. Midwest Gen and Dominion, we simply gave the information.

MR. KIM: Okay. And then I understand that you feel constrained, because of your contract, from a proprietary standpoint, that you cannot provide the information that we received in our questions.

Do you know -- and you, to the extent or the best of your knowledge -- do you know if your clients' utilities would have the same response if the question were put to them in terms of them being able to provide the Board with that information? I understand that you're not an employee of one of the utilities.

MR. DePRIEST: I don't want to put any words in their mouth, but I think Ameren has kind of told everybody what they're thinking about doing.

MR. KIM: Do you know if -- well, and Ameren has sort of put themselves into a sort of a special box in these proceedings. The other clients that you work with, do you have any kind of understanding as to their position on this?

MR. DePRIEST: I can only tell you what I think is public. I mean, Dynegy certainly has made it public, what they intend to do at a number of their stations. That's probably the extinct of what I know.

MR. KIM: Sure. My last question is, did you have an opportunity in the course of preparing your testimony to review any of the documents contained in the Illinois EPA's Technical Support Document, or TSD, that was submitted in conjunction with the rule of the Board?

MR. DePRIEST: You know, I glanced at it. I -- I didn't really -- I was looking for this TTBS thing, I didn't find it, so...

MR. KIM: Well, specifically, there's a table in the TSD, Table 8.9, and it's captioned as or identified as Example Technology Section, Selection and Cost For Illinois Mercury Rule Compliance. And that was an attempt by Dr. Staudt on behalf of the Illinois EPA to do a plant by plant and unit by unit breakdown of estimated technologies and costs and so forth.

Have you seen that table, by any

chance?

MR. DePRIEST: You know, I did glance at that. In fact, I made reference to one numbered in here, because one of the examples that we have used in here was the same -- one of the same stations that Dr. Staudt looked at.

MR. KIM: In the course of your site by site or unit by unit analysis that you did for your client, did you perform a similar type of breakdown or estimate?

MR. DePRIEST: You have to tell me what's on that table, I can't remember.

MR. KIM: I can show it to you.

MR. DePRIEST: Okay. And just for clarification, this is Table 8.96 TSP.

MR. KIM: Correct.

MR. DePRIEST: Yeah, it looks consistent with the information we also developed.

MR. KIM: Okay. Thank you.

HEARING OFFICER: Mr. Nelson first and then Mr. Harley. Mr. Nelson --

First you, Mr. Harley.

MR. HARLEY: In your testimony when

you were talking about going out and doing this assessment work for your utility clients, you talked about determining what they would need to do for CAMR, for CAIR and determining what they would need to do for the Illinois Mercury Rule.

Did you specifically parse out what would be required for compliance with each of those programs, or was it not in compliance with the full speed of near term regulatory requirements?

MR. BONEBRAKE: And again, objection. I think Mr. Harley is mischaracterizing the prior testimony.

But go ahead, Mr. DePriest.

MR. DePRIEST: Well, maybe if they tell you the dates that we did this work will help identify whether or not we were looking at CAIR, CAMR or the Illinois Rule. The Ameren work, we did that in 2003, 2004; Midwest Gen work we did in 2005; Dynegy work in 2004, 2005.

So you can probably look and see that the Ameren work was done prior to the Illinois Rule being proposed. So that part of it they did, based on information we gave them,

back in 2003, 2004.

They used that then as -- and probably modified it, as necessary, to represent the current day costs, and use that as part of their Illinois Rule evaluation.

MR. HARLEY: The work that you did for Ameren in 2003, 2004, was it mercury only or was it also looking at issues related to compliance with near term SO2 and NOx productions, as well?

MR. DePRIEST: It also looked at NOx, SO2 and mercury.

MR. HARLEY: So is it fair to say that the alternatives that you identified for these companies were alternatives and costs that would be associated both with mercury compliance and also with compliance with NOx and SO2 limits?

MR. BONEBRAKE: And just for clarification, is that question beyond Ameren? Is that all the companies that Mr. DePriest has mentioned?

MR. HARLEY: Why don't we start with Ameren.

MR. DePRIEST: Is that the same question you just asked me a minute ago? I

think the answer is yes. We looked at all three companies.

MR. HARLEY: And the cost for Midwest Generation, it would have been the costs and alternatives that would be required, not only for mercury compliance, but also for requirements related to NOx and S02 reduction?

HEARING OFFICER: And just for the record, NOx is N-O-sub X, S-O-sub 2.

MR. DePRIEST: That's correct.

MR. HARLEY: And the third company was Dynegy?

MR. DePRIEST: That's correct.

MR. HARLEY: The same is true for the assessment you did for Dynegy?

MR. DePRIEST: I'm thinking, Dynegy.

I would say -- I believe that's true. I'd like to go back and look at the report to be sure that we covered, you know, every one at every unit.

I'm not positive, but I'm pretty sure we did.

MR. HARLEY: Is it fair to say that the alternatives that you recommended for these

companies would be designed to control not only mercury but also have the additional benefit of controlling other things, as well, like NOx and SO2?

MR. BONEBRAKE: And again, I think you're mischaracterizing the testimony regarding the recommendations of the multiple companies.

But you can proceed. Go ahead and answer.

MR. DePRIEST: We gave them enough information for them to be able to independently evaluate the client strategies for each individual pollutant, as well as developing strategies that were comprehensive in nature to be able to find a solution for all, two, three. So the information was robust enough for them to be able to, let's say, develop an independent mercury control.

MR. HARLEY: Thank you.

HEARING OFFICER: Mr. Nelson.

MR. NELSON: First, I'd like to thank you for putting yourself under a microscope today.

If these reviews in your cost

calculations were calculated in 2003, 2004 and even 2005, how many demonstrations -- how much data did you see on brominated carbon injection into ESPs for subbituminous coals?

MR. DePRIEST: Well, it's difficult to answer. If you go back to 2003, it was pretty slim pickings.

In 2004, I think we had some data. In 2005, we had some data.

MR. NELSON: Was it --

MR. DePRIEST: I think Holcomb was 2004; wasn't it?

MR. NELSON: And then it took awhile for the results to be public; right?

MR. DePRIEST: Yes. Even though we had -- we had some access to them.

MR. NELSON: Now, Holcomb deals with a fabric filter in a spray dryer; does it not?

MR. DePRIEST: Yes, it does.

MR. NELSON: And those aren't the kind of plants that your clients have; are they?

MR. DePRIEST: No. But they could have, depending on their --

MR. NELSON: They could.

MR. DePRIEST: -- strategy for other pollutants.

MR. NELSON: But with respect to performance data, on brominated carbon and subbituminous coal and simply cold-side ESPs, which is the nature, by far, of the configuration in Illinois, you had no data then to reach your conclusions; is that correct?

MR. DePRIEST: Well, we, I guess, didn't really reach any conclusions. We provided information as to what it would cost to deploy these technologies.

And I think, even though I gave you static days and times, we continued to advise and consult our client on the work that we did. And we continued to update that information as they feel is appropriate.

So we did the base study on those years, but we have continued to work with them, even to today, on how that data might change.

MR. NELSON: Well, let me ask you specifically, have you yourself reviewed the detailed month-long trial results of ADA-ES with brominated carbon Ameren's Merrimac Station?

MR. DePRIEST: Yes, we have looked at that.

MR. NELSON: Were you aware that they averaged out 93 percent mercury removal for the month at an injection rate of a little over three times for ACF?

MR. DePRIEST: We're aware of the data to that respect, yes.

MR. NELSON: Are you aware of any deleterious ESP effects or passing increases that they reported?

MR. DePRIEST: We understand that the data looks very encouraging. It's also important to know that it's a very large ESP, very long inlet ductwork, no SO3 conditioning.

MR. NELSON: Have you reviewed the detailed month-long trial results of the ADA-ES with brominated carbon at the Laramie River Station?

MR. DePRIEST: No, I have not.

MR. NELSON: Which has an ESP of --

MR. BONEBRAKE: Is that a question?

MR. NELSON: I'm not finished with the question.

So you weren't aware that they averaged over 90 percent renewable injection rates?

MS. BASSI: He's answered that question. He's said he's not familiar with it.

MR. NELSON: Have you reviewed any of the results from ALSTOM's month-long trial at Pacific Corp's, Dave Johnston Station of brominated carbon?

MR. DePRIEST: No, I've not.

MR. NELSON: You're not aware of that one either?

MR. DePRIEST: No.

MR. NELSON: Have you reviewed the detailed trial results of the Sorbent Technologies month-long trial at the Detroit's Edison St. Clair Station, brominated carbon, subbituminous coal and --

MR. DePRIEST: Yes. Let me clarify.

I hate to -- I'm kind of answering for myself, I've got a staff of a lot of other technical experts who do review this information.

I'm certainly aware of the

testimony that was done at Laramie River, Dave Johnston and the Detroit Edison project, yes.

MR. NELSON: Are they here today to testify?

MR. DePRIEST: No, they aren't. I'm kind of testifying as the representative group that did the work.

MR. NELSON: But you yourself are not aware of any of these detailed results?

MR. BONEBRAKE: Objection. He's already answered that question.

MR. DePRIEST: I mean, not enough to be able to answer the questions.

MR. NELSON: Are you aware of the trial results of the URS Corporation's demonstration last year with brominated carbon injection at Great River Energy Stanton Station Unit 1 with cold-side injection, subbituminous coal and brominated carbon?

MR. DePRIEST: Not specifically, no. Not these specific data, no.

But that type of information was used to help us draw the conclusions at the river, if that's where you're going.

MR. NELSON: If those results -- and most of these results were just released within the last year, or in some cases six months, how could they have informed your recommendations and your cost calculations done in 2003, 2004, and 2005?

MR. DePRIEST: As I mentioned, we've been continuing to work with our clients updating the information that we originally developed in those years that we started that work, to assist them in them creating their own strategic plans. So as the industries moved, we've helped our client move with that information.

And granted, you know, you mention all these tests, and I would be the first one to admit that a lot of this stuff looks very encouraging. But it's also very short term, there's also a lot of things that we don't understand about why it happened to perform the way it did, either good or bad.

And some of those things make us feel uncomfortable about predicting that we'd be able to achieve these same results on the units

that we're applying to. Many of those units, as you mentioned, do not use SO3 injection for particulate control, their particulate control devices were designed to operate on low sulphur coals, which is now what we're operating the Illinois units on.

The Illinois units were not designed for the sulphur coals. Those units that we mentioned, Dave Johnston, Laramie River, I remember the Stanton Station.

MR. NELSON: Do any Midwest Generation plants do SO3 injection?

MR. DePRIEST: I believe not.

MR. NELSON: Do any Dynegy plants?

MR. DePRIEST: I believe they do.

MR. NELSON: Which ones?

MR. DePRIEST: I don't know, because we just -- I think we just switched Wood River over to low sulphur coal with --

MR. NELSON: Are you aware --

HEARING OFFICER: Let him finish, Mr. Nelson.

MR. DePRIEST: -- with SO3 injection, I believe. I'd have to --

MR. NELSON: Are there alternative testing for injection for fuel gas conditioning?

MR. DePRIEST: I understand there are, yes.

MR. NELSON: Are you aware of any of the DOE trials where brominated carbon was simply injected upstream of an ESP at a plant that runs primarily subbituminous coal was not able to achieve at least a 90 percent mercury removal?

MR. DePRIEST: I'm not aware of any.

MR. NELSON: Are you aware of any DOE trials where subbituminous coal, ESPs and brominated carbon injection that observed opacity increases over ESP problems?

MR. DePRIEST: I'm not aware of any.

MR. NELSON: Are you aware of the ESP and particulate emission results -- wait, just let me take a step back.

Were you aware of DOE trials that indicate improved opacity performance with brominated carbon injection, for example, Progress Energy's Lease Station?

MR. DePRIEST: I have heard some

things about that. I am a bit baffled by it, but yes, I've heard that.

MR. NELSON: Are you aware of the ESP and particulate emission results at Stanton 1, which burned subbituminous coal because of cold-side ESP?

MR. DePRIEST: Not the specifics, no. I understand that they didn't have any trouble with their particulate loading. But I don't know the actual specifics.

MR. NELSON: Are you aware that in the particulate emission measurements that particulate emissions went down with the brominated carbon injection relative to the baseline period at Stanton 1?

MR. DePRIEST: I heard that. Have those results been repeated?

MR. NELSON: Yes. Would you like to see them?

I'd like to enter this into evidence, if I may.

MR. DePRIEST: It sounds like we may have a new emerging technology.

HEARING OFFICER: That first document

that I've been handed is Great River Energy Stanton Station Unit 1. We will mark this as Exhibit 116 if there is no objection.

MR. NELSON: And the second document?

HEARING OFFICER: I haven't admitted the first document yet.

Is there any objection to the admission of the first document?

MR. BONEBRAKE: The first document being?

HEARING OFFICER: Great Rivers Energy Stanton Station Unit 1.

MR. BONEBRAKE: I will reserve my objection until we find out a little bit more information regarding this document, Madam Hearing Officer.

HEARING OFFICER: All right. For purposes of the record, we're going to mark this as Exhibit 116.

(WHEREUPON, a certain document was marked Exhibit No. 116 for identification, as of 8/18/06.)

HEARING OFFICER: And give me one second for the second document.

The second document is a Mercury Control Field Testing at Stanton Station Unit 1, draft site report prepared by Lynn Brickett, dated April 2006. If there's no objection, we will mark this as Exhibit 117.

Seeing this as Exhibit 117.

(WHEREUPON, a certain document was marked Exhibit No. 117 for identification, as of 8/18/06.)

MR. NELSON: I'll call your attention to the short document. Both of these are in the longer document, I just took out two graphs from the longer document.

HEARING OFFICER: So these are a part of the Lynn Birkett report?

MR. NELSON: Exactly. Just larger.

MR. BONEBRAKE: I'm sorry, I have two documents in front of me, one of which has been marked Exhibit 116 and is a longer report. It's your representation, Mr. Nelson, that 116 is an extract from the larger report?

MR. NELSON: Exactly.

MR. BONEBRAKE: And for clarification, can you tell us what page this is an extract

from? That is -- 116 is extracted from what pages of the report?

MR. NELSON: Pages 39 and 54.

MR. BONEBRAKE: And the larger report, Mr. Nelson, is black and white, what has been reported to be an extract is in color. Is it your representation that the color is from the original version?

MR. NELSON: Yes, they are. And I will give a PDF version so that you can get the whole thing in color.

If we look at the first page, please, does this look like the month-long, or actually longer than a month, from 9/15/05 to 10/27/05, where later mercury continuous emission monitor plots of inlets -- or excuse me mercury removal versus time?

MR. BONEBRAKE: And for clarification, Mr. Nelson, you're asking that question based solely upon his review of this particular page?

MR. NELSON: Just today, right. Just today.

MR. DePRIEST: What was the question? It looks like a month's worth of data, yes, or a

little more.

MR. NELSON: I call your attention to the top right-hand corner. Does it look like the injection rates in orange from below two and a half to a little over three pounds per million ACF on the right axis at the subbituminous coal plant with a cold-side ESP, they were able to achieve over 90 percent mercury removal?

MR. DePRIEST: Yes.

MR. NELSON: Are you familiar with the URS Corporation?

MR. DePRIEST: URS?

MR. NELSON: USR that performed this trial?

MR. DePRIEST: Yes.

MR. NELSON: Do you have a -- would you like to express an opinion as to their competence?

MR. DePRIEST: I have no reason to believe they are not competent.

MR. NELSON: Are they a sorbent supplier?

MR. DePRIEST: Not that I'm aware.

MR. NELSON: Are you aware that they

supply activated carbon injection equipment?

MR. DePRIEST: I understood that they were thinking about doing that. Are they a supplier of that now?

MR. NELSON: I'm not aware of that.

So it looks like this plant is another plant that they got 90 percent at very low injection rates.

MR. DePRIEST: Right.

MR. NELSON: The injection rates that --

MR. BONEBRAKE: Is that a question, Mr. Nelson?

MR. NELSON: The injection rates they're talking about, two to three and half pounds per million cubic feet of gas, what does that translate to in additional mass loading to the ESP?

MR. BONEBRAKE: For clarification, are you talking about this particular plant or just generally?

MR. NELSON: Any plant. It would be the same.

If you add about two pounds to

three pounds per million cubic feet of gas to a subbituminous coal plant ESP, approximately how much in percentage terms would you be increasing the loading to that ESP?

MR. DePRIEST: Well, that sounds like a calculation to me, I can't do it in my head. Certainly, it's a function of the ash loading without that, and which is a function of the fuel you were burning, lignite, BRB, bituminous all different ash levels.

MR. NELSON: Would you be surprised if it was a one to two percent increase in loading to ESP?

MR. DePRIEST: It wouldn't be a surprise, no.

HEARING OFFICER: I'm sorry, I didn't hear that answer.

MR. DePRIEST: It wouldn't surprise me, I guess. But, you know, it depends on the ash loading.

MR. NELSON: The ash systems that your company designs or specifies, ash handling systems, how much variability day-to-day or coal do you -- in percentage terms, what is their

turn-down ratio or turn-up ratio, typically?

MR. DePRIEST: For the ash --

MR. NELSON: For the ash.

MR. DePRIEST: -- Removal system?

MR. NELSON: Uh-huh.

MR. DePRIEST: The ash removal system is operated on an intermittent basis, as you fill the hoppers below with the ESP or the fabric filter.

MR. NELSON: Okay.

MR. DePRIEST: So it's not a continuously operating system, it operates when detected that the levels in the hoppers require that.

MR. NELSON: The ash loading to a typical ESP varies on a weekly basis or daily basis by what kind of fraction, five to ten percent, plus or minus 20 percent?

MR. DePRIEST: Whatever the variation in the fuel ash level is. If you're getting at will the addition of activated carbon, somehow or another, impact the ash handling system, I don't expect it would.

There's enough margin to handle

it.

MR. NELSON: More precisely, the ESP operation -- does the loading to the ESP typically vary, plus or minus ten or 20 percent, on a daily or a weekly basis?

MR. DePRIEST: If you're dealing with lignite, it's going to vary even more than that. If you're dealing with a bituminous coal, probably not that much.

MR. NELSON: What about a subbituminous coal?

MR. DePRIEST: Subbituminous coal, I wouldn't -- you know, because it's a fairly low ash, it doesn't take much to change it from a percentage standpoint. So it might be a fairly --

MR. NELSON: Like high, like ten or 20 percent?

MR. DePRIEST: I hesitate to give you numbers without looking at data, but...

MR. NELSON: Thank you.

Let's turn to the second page. I'll give you a minute to look at this.

I've added the pink circles, they

aren't in the original.

HEARING OFFICER: I'm sorry, you've added what?

MR. NELSON: The pink circles. They're not in the original URS or DOE documents.

Could you read the line with the second circle that describes the range of the red dotted line.

MR. DePRIEST: It says range of single point baseline measurements from July parametric.

MR. NELSON: And they vary between about what emission concentrations with baseline conditions?

MR. BONEBRAKE: Madam Hearing Officer, we're getting into an issue, as we did yesterday, where Mr. Nelson is simply asking a series of questions of the witness, which essentially are nothing more than the witness reading something from documents, that which you've seen before, into the record. The documents speak for themselves. This particular document has been marked as an exhibit.

If there's something that needs to be drawn by the Board from the document, it's part of the record.

HEARING OFFICER: I believe we're going to give him a little leeway, because I suspect that, as he was with the first document, he is establishing Mr. DePriest's familiarity so that he can then ask him questions about concluding.

Is that correct? You aren't just reading the document?

MR. NELSON: No, Mr. DePriest has testified. The whole basis of his testimony on costs has to do with required increases of particulate emission requirement, ESPs, that had to be larger fabric filters that have to be built to increase particulate emissions.

And I'm trying to establish the level of his experience in looking from these activated carbon injection and the actual data on effects on whether particulates increased or not.

MR. BONEBRAKE: It mischaracterizes his testimony, but the record will say what it

says.

MR. GIRARD: Let me ask a question.

Mr. Nelson, the figure 5-10 on Page 39 of Exhibit 117 is before us. What do you think that figure shows?

MR. NELSON: In summary, I think that it shows that over the course of this 30 or 34-day test, that the particulate emissions with the brominated activated carbon injection at this plant actually do not show increased particulate emissions, but actually show equivalent or decreased particulate emissions. That these blue bars (indicating) are not above the top red line of the baseline measurements without activated carbon injection.

But particulate measurements are actually within the standard band, or with time, go down with brominated carbon injection. That's all.

MR. GIRARD: Thank you.

Mr. DePriest, is there anything in Mr. Nelson's explanation that makes you want to change anything in your testimony?

MR. DePRIEST: I don't think so. If I

could comment on this though, maybe I would --

HEARING OFFICER: Please do.

MR. GIRARD: Yeah. What comments do you have?

MR. DePRIEST: Well, I'd like to know how this system operated just normal variation of the particulate loading that you would normally see on a unit like this, operating without any activated brominated or otherwise carbon in it. Is this a -- the blue line here (indicating), is that representative of normal background emission limit fluctuation at the Stanton Station? I mean, these don't look particularly -- the variation isn't a surprise to me, even without activated carbon injection.

So I'm wondering whether or not that unit would run like this, activated outlet loading with or without brominate. I'd like to know that.

MR. GIRARD: Well, Mr. DePriest, Exhibit 117 is an 81-page draft, professionally papered. Do you think you would need more time to read this paper to answer the questions you have posed?

MR. DePRIEST: I'd -- that would be welcome, if I could.

MR. GIRARD: Did you think there's a good chance that the questions that you have would be answered in the paper?

MR. DePRIEST: They will either be answered or I'll have questions about the data in the paper as to how it's -- whether or not they scientifically really looked at the effect that the addition of activated carbon had on the performance of that precipitator in question. Certainly, you'd want to establish -- get a good background for how it runs, day in and day out, particulate loading, maybe even similar to this without activated carbon, such as, they added activated carbon and nothing changed, is a good possibility.

I'd like to get into that type of an analysis with the authors of this paper, whether they looked at that.

MR. NELSON: Okay.

MR. DePRIEST: And, I guess, I'm a little concerned about the range of single point baseline measurements as to what that means,

single point.

MR. NELSON: Well, they are baseline measurements. The red is what it is without injections.

MR. BONEBRAKE: Well --

MR. DePRIEST: It's a single point. And we all know, although when it comes to sampling for particulate in a fuel gas stream, single point is meaningless.

MR. NELSON: In a traverse, how many points are typically standard?

MR. DePRIEST: The EPA has rules and guidelines as to how to traverse a duct. And it's a function of, you know, how many duct diameters downstream from the disturbance in the flue gas path.

I'd say, typically, you're going to be sampling, somewhere in the neighborhood of 48 points when you do a traverse. At least if you follow the EPA guidelines.

I know, I see you shaking your head. But if you look at Method 1, EPA Method 1, it's going to tell you.

Most power plants doing the

ductwork configurations is going to require a fairly robust number of sampling points to achieve the requirements of Method 1 IEPA federal register guidelines.

MR. NELSON: Last question.

If the particulate measurements showed particulate emissions greater than the baseline period, would you think that that would be evidence of an increased particulate emissions with sorbent injection?

MR. DePRIEST: I guess I'd have the same comment. I'd like to be able to be sure you understood the background baseline particulate emissions from the station without carbon injection, long term as compared to, you know, whatever you mentioned here about a particular day, 10/20/2005, when you happen to be injecting between three and three and a half pounds and doing better than 90.

It's very encouraging information, and I'd like to dig into it.

MR. NELSON: Thank you.

MR. BONEBRAKE: Just one follow-up question.

HEARING OFFICER: Sure.

MR. BONEBRAKE: Mr. DePriest, Dr. Girard asked you a question about whether it would be helpful or assist you to have more time to view the report dated April 2006, and you answered that question. And my follow-up is, as Dr. Girard pointed out, that report is entitled Draft.

Would it also assist you in forming any special opinions, based upon which document to review, the final version rather than a drafted version of the report?

MR. DePRIEST: Oh, certainly if there's a final.

MR. BONEBRAKE: Thank you.

HEARING OFFICER: Okay. I have to ask this follow-up then.

I understand that this is a draft paper, but would you expect to see substantial changes between a draft that circulated publicly and a final draft on a report of this type, when it comes to the data?

MR. DePRIEST: Well --

HEARING OFFICER: Is the data going to

change between the draft and the final?

MR. DePRIEST: My only concern is the scientists that did this work would -- and I assume they're looking at the data and looking for inconsistencies or unexplainable occurrences in the data that might result in them actually pulling some of the data their report based on such an analysis. Whether or not that's been done, is part of them developing a draft.

I'm not sure, but I wouldn't -- to answer your question, I'd be surprised to see that happen, but it wouldn't be totally out of the question.

HEARING OFFICER: Okay. Thank you.

MR. GIRARD: Mr. Nelson, do you know if this paper has been through the DEO or EPA or whoever has commissioned it, their review process? I mean, there are drafts and there are drafts, has this been peer reviewed in any way?

MR. NELSON: I was told by DOE that this will probably not be published in its final form as an individual site report. It's part of a larger contract that involves like three different plants, that's typically the way they

do it.

And then it will appear in a final report that will include all three plants. So this will be like one chapter in a three chapter final report.

And that won't be done until they finish the last plant, which is -- you know, it may not actually be out for another year. But this is kind of a status, they're done with this, it was completed almost a year ago.

They moved on to the third plant now. So this is probably where it will be, it will just be a subset of a much larger document.

MR. GIRARD: Thank you.

MR. KIM: I have one follow-up question.

Mr. DePriest, was it your testimony that, even without carbon injection, that there -- you would expect to see variability as far as particulate matter?

MR. DePRIEST: Oh, absolutely, yes.

MR. KIM: Okay. Thank you.

HEARING OFFICER: Question 17.

MR. KIM: Thank you.

HEARING OFFICER: Thank you, Mr. Nelson.

MR. BONEBRAKE: I'm just wondering, we've been at it for about an hour and 40. Time for a break?

HEARING OFFICER: I'd like to go another ten minutes or so.

MR. DePRIEST: Question 17.

On Page 11 you also state that: "The capabilities of these existing ESPs to capture these sorbents without exceeding particulate/opacity limitations will vary significantly across the coal-fired units in Illinois."

Question A. Does that suggest that you believe that some units will have acceptable performance while others do not?

My answer is, it is possible, although guarantees may not be available from suppliers.

Question B. Doesn't the temporary technology-based standard address the concerns for those that may have difficulty?

And my answer is, the TTBS

provides limited relief, but only for a fraction of the units. We do not know if this will be sufficient.

HEARING OFFICER: Question 18.

MR. DePRIEST: Regarding your stated concerns on Pages 12 through 14, No. 2 through No. 6, are these not largely the result of your client's position that the only way to comply with the proposed Illinois Rule is by retrofitting fabric filters on every unit?

My answer is, the concerns would apply to any individual unit that would require a fabric filter or compliance. In other words, where the ESP would not be able to achieve mercury capture.

HEARING OFFICER: Go ahead, Mr. Kim.

MR. KIM: So, I guess, to turn that answer around, if compliance with the Illinois Rule were possible without the need for a fabric filter, would those stated concerns that were identified largely go away?

MR. DePRIEST: Oh, yes, they would. Right.

HEARING OFFICER: Question 19.

MR. DePRIEST: Question 19.

Regarding your stated concern No. 7, "Waste Disposal Limitations," if a fabric filter is used as you have testified power plant owners believe it's necessary, does this concern not largely go away?

Answer, with the mercury-specific fabric filter, the waste disposal concern goes away if the existing precipitator can be kept in service to capture the fly ash prior to carbon injection. Clearly, the spent activated carbon injection captured in the fabric filter would need to be disposed of if the contamination of all the fly ash would be avoided.

No. 20. Regarding your stated concern No. 7 -- same thing. And your statement, "If the existing ESP is used to collect the mercury sorbent, the operator will need to make the necessary provisions for landfill of the unmarketable fly ash, with the attendant costs and secondary environmental risks."

Do you agree that these additional costs are already included in the estimated cost

of the rule in the Technology Support Document?

I have not done a detailed analysis of the Technical Support Document to determine whether the costs are realistic, but understand that it was the intent to account for landfill costs in that document. We understand that another witness is addressing, or I guess did address, this ash disposal issue yesterday.

No. 21. Regarding your statement on Page 15, "Current projections for flue gas desulfurization projects required to meet the SO2 requirements of Phase I of CAIR will require the installation of over 150 new FGD systems representing over 60,000 megawatts of coal-fired capacity in the U.S. These new FGD systems will go into service between 2006 and 2010 and represent a market that is more than seven times the size of that which was achieved in all of the 1990s.

"This environmental market, in conjunction with the ongoing SCR program for NOx and the accelerating construction of new coal-fired plants across the country, is straining the capabilities of industry resources

to keep up with both the quality and quantity demands of the utility industry."

Question A. If it were possible to comply with the Illinois Rule through sorbent injection alone, without the need for fabric filters, except on the two units with hot-side ESPs, would that not largely mitigate the issues you discuss here and in the following pages through Page 20?

And my answer is, yes, if it was possible to comply with sorbent injection alone.

Question B. With specific regard to your statement "These new FGD systems will go into service between 2006 and 2010 and represent a market that is more than seven times the size of that which was achieved in all the 1990s," do you think suppliers of FGD technology consider the 1990s a particularly robust period of business, or would it be better characterized as somewhat of a disappointing level of FGD activity?

Wasn't the '90s a fairly slow period for the scrubber business with most of the compliance activity associated with coal

switching?

My answer: We are not able to speak for the FGD system suppliers' perspective on the 1990s. We do know that the major FGD suppliers have indicated that the current market is extraordinarily busy and that their ability to respond to all requests for equipment has become very limited.

Question C. In contrast to the low level of FGD business in the 1990s, roughly how many megawatts of coal-fired SCR systems were installed in the period 1998 through 2005?

My answer is, I do not have these figures immediately available, but I believe that -- and I may be wrong here -- I believe that Mr. Cichanowicz has spoken to this issue in the previous couple of days. And I do understand that the U.S.EPA has information along the lines of your request.

Now, I can say, as an additional comment, that Sargent & Lundy worked on 53 different SCR projects during that time frame. And then, of course, there was a number of other ones going on.

HEARING OFFICER: D.

MR. DePRIEST: D. Roughly how many combined cycle plants, which nearly all required SCRs and many man hours of boilermaker craft labor, were brought on line in that same period?

Again, I do not have the answers to these figures particular -- I do not have these figures. But there is no comparison between the labor requirements for a combined cycle construction and coal plant construction and retrofit projects.

HEARING OFFICER: E.

MR. DePRIEST: E. By and large, were these air pollution control projects, admittedly costly and difficult, performed satisfactorily by the air pollution control industry?

Yes. But, as discussed, an unprecedented number of projects will be competing for, essentially, the same resources that were available in the 1990s. Granted, these resources are responding to the demand of expansion of their capabilities, but the strain is evident and a significant concern to all that participate in this business.

F. Doesn't the air pollution control industry include some of the largest pollution control companies in the world?

My answer: Even the largest air pollution control companies have indicated to us that they are being selective about which projects they bid due to the busy market.

Also, many of the air pollution control companies are not in the business of actually fabricating or constructing their own equipment, and therefore, rely heavily on other less substantial companies for many of their system components.

HEARING OFFICER: Mr. Kim.

MR. KIM: Oh, I was going to say -- I was jumping ahead to No. 22, and I was going to say that I think it's already answered. But if Mr. Harley has a follow-up...

HEARING OFFICER: Mr. Harley.

MR. HARLEY: In your statement on Page 15, which was quoted in the question, these upgrades in pollution control equipment are represented as being done in order to satisfy CAIR requirement; is that correct?

MR. DePRIEST: Well, I think, principally, you're right. Principally CAIR. There are other projects that are ongoing for other reasons, but principally CAIR.

MR. HARLEY: And regardless of whether or not there were a Mercury Rule, either on the federal or state level, it would still be required to make these upgrades in order to meet the requirement of CAIR; is that correct?

MR. DePRIEST: That's correct.

MR. HARLEY: And later you talk about upgrades which are being done in the industry -- pollution control equipment offerings that are being done in the industry, in order to meet NOx requirements; is that correct?

MR. DePRIEST: That's correct.

MR. HARLEY: And those upgrades would have to be done by utility operators, regardless of whether there were a Mercury Rule or not; is that correct?

MR. DePRIEST: That's correct.

MR. HARLEY: Of the 150 new FGD systems which are being installed, are you aware of any which are being installed in Illinois?

MR. DePRIEST: Yes, I am.

MR. HARLEY: And those projects are being done in order to satisfy CAIR requirements; is that correct?

MR. DePRIEST: Well, I think it's public knowledge that Dynegy is operating under a consent agreement on another subject, but they also have CAIR requirements also. So whether or not they're doing it for CAIR -- they're doing it, nonetheless.

MR. HARLEY: It's correct then to state that CAIR imposes an independent set of requirements that will lead to pollution control upgrades at many electric generating units across the country?

MR. BONEBRAKE: Independent of the Mercury Rule?

MR. HARLEY: Yes, that's correct.

MR. DePRIEST: That's correct.

MR. HARLEY: And requirements relating to NOx, will, similarly, create an independent basis for significant investment in pollution control equipment and coal-fire power plants across the country, by independent, and

Mr. Bonebrake will clarify, independent of what the Mercury Rule would apply to?

MR. DePRIEST: That's correct.

MR. HARLEY: Thank you.

HEARING OFFICER: And I agree with you that No. 22 has been answered. So let's go on to 23 and we'll take a break.

MR. BONEBRAKE: I'm wondering if 23 has also been answered, at least in part, because there was some discussion earlier about assessments that had been done for various companies.

MR. KIM: I would agree that 23A, likely, has been asked and answered. And assuming that for proprietary concerns, would continue to be an issue, likely 23B has been asked and answered.

I'm assuming 23C has been asked and answered and I don't know that 23D has.

MR. DePRIEST: It's going to be the same answer, but I'll read it.

MR. KIM: Okay.

MR. DePRIEST: What are the expected reductions, if any, in mercury emissions in

pounds reduced per year, presented to reduce per year from a given base year as a result each plant's federal CAMR compliance strategy in Phase I, same question for Phase II of CAMR. Please use a year from 2002 to 2005 as the base year available. If not, please identify the base year.

MR. BONEBRAKE: I first just wanted to put an objection on the record that the question seems to assume that each plant, I'm assuming that's in Illinois, has a federal CAMR compliance strategy in place. And I don't know if there's been any factual predicate for that.

And I don't know if these witnesses' positions speak to what all of the companies have done or are doing given prior testimony about providing data but not specific to certain companies. So there's some foundation assumptions that are built into this question that I think are either open or inconsistent with the testimony to this point.

MR. KIM: And I think, as long as the question -- the context of the question is limited to companies that you have identified

previously as being clients of yours, then I think, you know, with that understanding, that I think Mr. Bonebrake's concern would be resolved.

MR. BONEBRAKE: You can go ahead and answer.

MR. DePRIEST: Does that require an answer?

MR. KIM: Well, no. I'm just saying that we would agree that if you do agree that your answer is conditioned on the fact that you're only answering as to the companies that are clients of yours; is that correct?

MR. DePRIEST: Yeah, and I probably won't answer it.

MR. KIM: The nonanswer answer you're providing.

MR. DePRIEST: I'm just looking at the detail here, and I guess we go back to my earlier testimony on this subject.

If you look at the work that we did for Dynegy and Midwest Gen, we specifically developed the cost performance, O&M, capital, et cetera, to the application of a host of different technologies and all their sites. We

didn't make those type of calculations you're talking about as to, you know, how many pounds of mercury might have been reduced or in their strategy, because we didn't develop a strategy.

MR. KIM: The only one follow-up I have then is just to go back and clarify.

I think you testified earlier when you did this analysis work -- well, maybe you can clarify for me.

You testified that you had done some analysis work on a plant by plant basis, I believe, to determine how they stood and compared with CAIR/CAMR and the Illinois Mercury Rule; is that correct?

MR. DePRIEST: I'd said the assessment that we did was the assessment of what it would cost capital and O&M-wise to apply a technology to that station to perform in a fashion of either reducing SO2, NOx or mercury. But not an assessment of how that particular station might fit into their overall strategy for compliance of the rule.

MR. KIM: And when you say "the rule," the three rules that I just described?

MR. DePRIEST: That's correct.
MR. KIM: Okay.
Nothing further on that question.
HEARING OFFICER: All right.
Then let's take a short break, about ten minutes, and come back and finish.
(WHEREUPON, a recess was had.)
HEARING OFFICER: And I believe we are on Question No. 24.
MR. DePRIEST: Question No. 24.
Have you conducted an assessment of which coal-fired power plants and electric generating units in Illinois would likely delay or completely avoid installation of mercury controls, such as they would need to purchase or use bank allowances for a period under the federal CAMR Rule due to installation of controls being uneconomical, difficult or for any other reason?
And I think, you know, in a way I've kind of answered this before, in that we developed the costs and the capital and O&M costs and performance expectations for the application of technology to all the units in

question. But we did not develop a strategy that said you're going to operate this one with the technology and that one without and therefore answer this question.

I do not know the answer to that question. That particular strategic plan was developed by the utility itself.

MR. KIM: So that is separate from -- that's all right, strike that.

HEARING OFFICER: Do you have an opinion, though, that there are utilities out there that it's so uneconomical, difficult to even meet the CAMR requirements, they would have to purchase allowances?

MR. DePRIEST: Well, yeah. Operating under CAMR, I think it's pretty clear, even though not absolute, that the smaller units, older, less heavily used units, would probably be the best candidates for those not to put technology on and to rely on over compliance and/or the purchase of allowances from other units, mainly because of the cost benefit of applying expensive technology and capturing very few pounds of mercury, it just doesn't make

sense.

HEARING OFFICER: Mr. Kim.

MR. KIM: But those smaller, older units that you described, at least in Illinois, those would be the units that would potentially be eligible to participate under the TTBS provision of the Illinois Rule; is that correct?

MR. DePRIEST: That's correct. As I mentioned earlier, that's a -- some additional flexibility is nice to have, even though it may or may not accommodate all the nuances that we might encounter.

MR. KIM: Thank you.

HEARING OFFICER: Twenty-five.

MR. BONEBRAKE: I think 25 has been answered by his answer to 24.

MR. KIM: That's correct.

MR. BONEBRAKE: And I believe 26, as well. Does that relate back to Question 24; Mr. Kim?

MR. KIM: Yes. We would agree.

HEARING OFFICER: Twenty-seven.

MR. DePRIEST: Twenty-seven. What would be the actual "additional and financing

costs" associated with installing a baghouse six years early, as referred to on Page 6 of your testimony?

And the answer is, the cost would be the interest costs associated with the capital budget, and, of course, the cash flow for spending that budget, but for each unit subject to the current interest rates available to the specific unit owner. So I would expect that number would be different for every unit and for every different utility, depending on their ability to borrow money to finance the project.

It's, essentially, financing it and installing it earlier than they have to.

HEARING OFFICER: Question 28.

MR. DePRIEST: Twenty-eight. Please provide documentary evidence of the "conclusion" of the owners of the Illinois' electric generating units, including the lack of precipitator margin as discussed on Page 10 of your testimony.

I believe we have gone over this in quite a bit of detail.

MR. BONEBRAKE: I think the sentence in question was referenced in an earlier question, as least as I understood this question.

MR. KIM: So your answer, I guess, would be what? Would this --

MR. DePRIEST: I think you'd probably go all the way back to the answer to Question No. 6.

MR. KIM: Okay.

HEARING OFFICER: Twenty-nine.

MR. DePRIEST: What ESP upgrade projects have Sargent & Lundy been involved with for existing ESPs other than adding additional collection area? See Page 12 of the testimony.

My answer is, we do not track our experience according to which modifications added collection area and which did not. However, our total experience includes 84 precipitator retrofits to existing boilers, precipitator performance improvement at 85 different existing units, 20 of them since 1990 and precipitator structural improvements at 42 units.

MR. KIM: Is that Illinois specific or is that your national clientele?

MR. DePRIEST: It's the national clientele.

MR. KIM: Do you have a breakdown as far as Illinois clients on that answer?

MR. DePRIEST: I could get that for you if you'd like, I do not have it with me.

MR. KIM: Maybe a written comment, that might be helpful to us.

HEARING OFFICER: Yes, please.

Mr. Harley.

MR. HARLEY: In performing these ESP retrofit projects, modification projects, is it ever necessary to install additional ductwork?

MR. DePRIEST: It might be. Some of the upgrades and/or retrofits -- certainly the retrofits -- would be additional ductwork.

The upgrades would include additional ductwork if we had to modify the field with a precipitator in some fashion that it ended up changing the arrangement of the ductwork coming through or leaving the precipitator.

MR. HARLEY: And so this could include installing extensions of existing ductwork?

MR. DePRIEST: If the arrangement dictated that.

MR. HARLEY: Thank you.

HEARING OFFICER: Off the record.

(WHEREUPON, discussion was had off the record.)

HEARING OFFICER: Back on.

Question 30.

MR. DePRIEST: Do electrical upgrades to the electrical system at a power plant provide an opportunity for electrical reliability or efficiency improvements? See page 12 of the testimony.

Generally, these types of upgrades are undertaken, at least with regard to environmental system upgrades, to handle the specific additional loads of the fans and other environmental-related control equipment. Certainly, we would take the opportunity to improve electrical reliability if there were existing issues that could be resolved with economic justification. However, these

opportunities for improvement are very rare.

HEARING OFFICER: Thirty-one.

MR. DePRIEST: Thirty-one. Are outage schedules adjusted when unforeseen problems arise with a generating unit?

The answer is, unit owners will take unscheduled outages when unforeseen problems arise, but only when absolutely necessary for as short a period as possible, due to the financial losses associated with being offline.

HEARING OFFICER: Thirty-two.

MR. DePRIEST: How many new FGD systems will be installed in 2008 and 2009 in Illinois out of the 150 new FGDs identified in your testimony?

And the answer is, the Illinois utilities' plans to install FGD units are confidential to the owners, and this question would be best directed to them. But I would add, you know, I think Ameren made it pretty clear which ones they intend to do, Dynegy has publically announced which ones they intend to do.

So the information is available and is becoming more public, I think.

HEARING OFFICER: So you can't, generally, answer how many of the 150 are Illinois based?

MR. DePRIEST: I can add them up in my -- I can think of 12.

MR. KIM: Can you -- I don't have the numbers available, as happens. Can you give a breakdown of the 12, how those were assigned by company? You said you identified Ameren and Dynegy.

MR. DePRIEST: You know, Dynegy has identified four.

MR. KIM: Right.

MR. DePRIEST: And it's clear, the consent decree, obviously, says what it says.

MR. KIM: Sure. I guess what I'm saying is, I guess, looking at it this way, aside from Ameren and Dynegy, and probably a balance, do you know what the remaining FGDs would be, who is going to be responsible for those outside of Ameren and Dynegy?

MR. DePRIEST: Well, I think if they

build that unit in Dallman, there's going to be a scrubber in that one, include that one in the list. I'm trying to think, I don't think there's anybody else.

I mean, Midwest Gen hasn't decided what they're going to do. Prairie State, if they build that, of course, there will be a scrubber and associated equipment on that one.

HEARING OFFICER: Mr. Harley.

MR. HARLEY: In your prefiled testimony on one of the final pages, you indicate that an FGD, in combination with carbon injection, is likely to meet the requirements of both CAMR and also the Illinois Rule.

Do you recall that?

MR. BONEBRAKE: Can you point us to a particular page, Mr. Harley?

MR. HARLEY: Yes, I can.

HEARING OFFICER: I think Page 25, Mr. Harley.

MR. HARLEY: Correct, Page 25. It's the first sentence.

MR. DePRIEST: Oh, where I say implementation of dry FGD with a fabric filter

for CAIR, SO2 compliance?

MR. HARLEY: That's correct.

MR. DePRIEST: In conjunction with a sorbent injection. Achieved in mercury control compliance with CAMR.

MR. HARLEY: Please continue reading.

MR. DePRIEST: And should achieve compliance with the proposed Illinois Mercury Rule.

MR. HARLEY: Thank you, that's fine.

In coming up with your cost estimates, where you have a piece of technology, like an FGD, which will both help achieve CAIR compliance and also will provide a co-benefit of additional mercury control, how did you allocate out in making your cost estimates? What portion of the cost of installing that FGD should be allocated to mercury compliance alone?

MR. DePRIEST: We did not allocate. We didn't try to differentiate the dollars that might go through SO2 control and specific technology.

We simply identified the costs of their technology, capital and O&M, and what we

expected its performance to be, SO2 and mercury.

MR. HARLEY: And so, if you were asked to provide an estimate for mercury control alone, you would include both the carbon injection system and also the total cost of the FGD unit?

MR. DePRIEST: Well, we didn't perform that exercise. I guess we could, even though I'm not sure it would make sense.

MR. HARLEY: Thank you.

HEARING OFFICER: A.

MR. DePRIEST: A. Why would 50 percent of Illinois' coal-fire generators take an outage in the spring of 2009?

Every unit that would require fabric filters to meet the proposed rule, would need to take an outage in early 2009. The 50 percent figure was used to illustrate the potential impact if installation of fabric filters affected only half of the Illinois units.

B. Why would this affect power availability if outages were staggered?

The outages can only be staggered

up to a point, due to the outage duration required, and due to the long lead time for fabric filter equipment.

Essentially, what I'm saying there is the long lead times for fabric filter equipment and design pushes us all into the spring of 2009 as to when we would be able to cut these into service, and it would all happen at once.

MR. KIM: I have only one follow-up. And it's not in response to this, but it just tags up to some of the earlier testimony.

And that was, I believe you testified that you gave some dates as to when your company began doing assessment work for Ameren, Midwest Gen and Dynegy. For example, I think Ameren you said began in 2003, 2004.

And I believe you testified that, since that time, you have been updating the information; is that correct?

MR. DePRIEST: That's correct.

MR. KIM: Could you just describe what you meant by "updating"? In other words, what actions are you taking or what kinds of things

are you taking into account when you update information? Starting from that initial -- whatever your initial results of your assessment.

MR. DePRIEST: Well, if you look at the market forces that are in play here, to go back to 2003, we started seeing some inklings of resource constraints in which we're driving the costs up, particularly in the craft labor area. And so as we moved along, taking that component of our cost estimates and advised our clients as to how that has changed since the initial work that we have done. That's one way.

Other ways that are, you know, probably a little more concrete, would be to actually take bids for some of the hardware, especially if you look at the work we're helping Dynegy with on the FGD program with the fabric filter. Some of those projects are actually under contracts, so those costs are much more firm today than they were when we initially started that work.

MR. KIM: Would those updating activities include revised cost estimates to

reflect changes or improvements in different, for example, carbon injection technologies?

MR. DePRIEST: Principally, in that the -- I'm trying to think of these -- in some cases it would be true. When we've included the requirement in our contract that the devices that we're purchasing actually do some mercury control, then it would.

Now, there's been a number of cases where we've purchased, or are under contract for FGD systems and fabric filter systems that don't require -- currently have a requirement in the contract for mercury control, so those would not. But those that did would.

MR. KIM: And is this updating done on an as-requested basis by the client, or is this -- how is this -- is there just sort of an understanding or a periodic kind of thing?

MR. DePRIEST: Well, we work very closely with these clients, so I guess you'd say it would be an on as-requested basis.

MR. KIM: That's all I have.

HEARING OFFICER: Mr. Bonebrake.

MR. BONEBRAKE: I did have a couple of

follow-up questions.

I think you mentioned the term lead time in connection with baghouse installation in a prior answer. Can you describe for the Board what lead time means and what the lead time period, generally, would be for baghouse installation at this particular point in time?

MR. DePRIEST: If baghouses were required for compliance with the 90 Percent Rule, we look very closely at the lead time required to get those into place on the Illinois units. And our assessment, speaking to the equipment suppliers, would be that it's somewhere in the neighborhood of 30 months, maybe a little bit more, from time of actual award to the equipment supplier to where he would have his equipment operating at commercial fashion.

So you have to put a few months in front of that, for us to write a spec and do some studies in order to define the hardware that we intend to purchase.

So it's somewhere between 30 and

36 months from get started to inservice and running commercially. So if you look at the schedule of a November of this year's final rule and then we get started on that date, and then we have a July of 2009 commercial operation date, it pretty much says that we're doing everything in the spring of 2009, from the standpoint of cutting it in to the existing equipment and infrastructure at the site.

MS. BASSI: Mr. DePriest, does that time include permitting?

MR. DePRIEST: It should be adequate to cover permitting.

MR. KIM: Because we're very quick with that.

MS. BASSI: Yeah, right.

MR. DePRIEST: I was going to say, I'm sure you'll be very cooperative.

MR. BONEBRAKE: One other follow-up, Mr. DePriest. Mr. Harley earlier asked you some questions regarding obligations to install NOx and SO2 control technologies under CAIR. And as you consider CAIR requirements, does the Illinois Rule pose some technical and cost

challenges that CAMR does not, because CAMR permits trading while the proposed Illinois Rule does not?

MR. DePRIEST: Clearly, the CAMR Rule that has a trading program involved in it offers a lot more flexibility to utilities to find the compliant strategy. And, in my opinion, it also significantly reduces the risk of lack of performance of a mercury-controlled technology applied to these coal units.

So if you look at the Illinois Rule, if the technology you put in, as currently proposed, could put in -- did not achieve the 90 percent reduction, there's virtually no recourse as to -- the way I read it -- as to an alternate solution. Whereas, the CAMR Rule, if you put in a technology expecting it to do 75 percent reduction of mercury and it only did 65 percent reduction, well, then you just go to the market -- the mercury allowance market and purchase some allowance to cover your shortfall.

So the risk is significantly different with the CAMR Rule than it is with the proposed Illinois Rule.

HEARING OFFICER: Mr. Harley.

MR. HARLEY: Just one further question to help clear the record up a little bit. You had previously testified in response to Mr. Nelson's inquiry about your knowledge of the use of brominated carbon injection. And although you were not personally aware of this results, there were individuals within your firm who were aware of those results and would be keeping your clients up to date on those results. For purposes of the record, can you identify who those individuals are?

MR. DePRIEST: Sure. Rise Gatewadd is one, Paul Farber is another, Steve Catsberger in another, Dave Sloat (phonetic). I could get you my work chart.

MR. HARLEY: No, that's fine. Thank you very much.

HEARING OFFICER: Mr. DePriest, I also note that Prairie State Generating Company filed a couple of questions for you. And although we may have touched on them, I'm not sure we specifically answered them.

The first question from Prairie

State was, what are the technical problems of reducing mercury emissions from high sulphur coal?

MR. DePRIEST: Yes. And I have a answer.

The most significant problem of mercury control with ACI and high sulphur coals is the potential for a high level of SO3 occurring naturally in the combustion process or being formed in the SER reaction, interfering with the absorption of mercury on the surfaces of the activated carbon.

HEARING OFFICER: Thank you.

MR. DePRIEST: I see that as being the -- by far, the most significant technical issue on high sulphur coal.

HEARING OFFICER: And the second question, go ahead and read it in.

MR. DePRIEST: Has it been demonstrated that 90 percent mercury control of high sulphur coals can be achieved over the long term? If not, what level of control do you believe is possible?

And my answer is, no long-term

demonstration of mercury control on high sulphur has been documented. In all likelihood, wet FGD systems on high sulphur coal, have been capturing a significant quantity of the oxidized mercury in the flue gas, although, there is little data showing this over a long period of time.

However, there are still some significant questions to be answered regarding FGD capture of mercury, including, one, potential for readmissions due to reduction of oxidized mercury in the FGD system. Two, degree of oxidation of mercury in the flue gas and its dependence on coal chemistry.

Three, the impact of various additives to the fuel on its oxidation level. Four, the impact of oxidation catalyst on mercury oxidation.

And Five, other -- I just threw in kind of a broad thing -- other developing technologies to promote oxidation and facilitate capture in the FGD system. Therefore, there is no one answer to this question and it will be evolving as more development of technology

occurs.

HEARING OFFICER: And I -- just as a point of clarification, you talked about long-term testing. What would you consider a long-term testing, what length?

MR. DePRIEST: Depending on the technology involved, I think, you know, operation, let's say, with activated carbon injection and upstream of a fabric filter. I would expect somewhere in the neighborhood of a year or more would be required to fully understand the impact that activated carbon injection has on bag life, for instance, because the cleaning process of the bag is what really determines its life.

And activated carbon, and its ability to clean it off the surface of the bag, is still not fully understood. And if we have to clean the bags very frequently, we're going to shorten the life of the bags, which might drive us to the installation of a larger baghouse to accommodate that to control bag life. Because bag life is a significant cost factor in O&M costs over the years.

As far as injection into an ESP, I think the testing requirements or demonstration requirements are far shorter, because I think we're going to know pretty soon whether or not that works. And the only real variables are variables in the ash chemistry that might affect that.

So getting some experience, as I mentioned earlier, the ash in coal is not very consistent, it varies significantly over time. And, you know, just to kind of get a feel for how all those variations might be experienced in the performance of mercury and particulates captured, particularly, nine months -- maybe, six, nine months.

It's hard to say. It's an emerging issue, you know, we'll learn things as we go.

HEARING OFFICER: Thank you.

Anything else?

MR. KIM: Thank you, Mr. DePriest.

HEARING OFFICER: Thank you very much, Mr. DePriest.

Mr. Marchetti is next.

Off the record.

(WHEREUPON, discussion was had off the record.)

HEARING OFFICER: Before we have Mr. Marchetti sworn in, I do want -- one housekeeping thing to take care of. I marked Exhibit 116 but had not entered it into the record. I will enter it into the record.

116 was the chart from Mr. Nelson, the Great River Energy's Stanton Station Unit 1 that had been taken from the draft report. I marked it and Mr. Bonebrake had reserved an objection, so I didn't actually enter it, so I'm going to enter it into the record now.

(WHEREUPON, said document, previously marked Exhibit No. 116, for identification, was offered and received in evidence.)

MR. BONEBRAKE: I would just make two points on that document. First, I believe Mr. Nelson testified that it was an extract from a document, which itself is entitled Draft, and second, I believe Mr. Nelson also indicated that he had made at least one or two changes to the

version of that document as set forth in the report.

HEARING OFFICER: All right. Can we have Mr. Marchetti sworn in, please.

(WHEREUPON, the witness was duly sworn.)

HEARING OFFICER: And if there's no objection, I will mark Mr. Marchetti's pretrial testimony as Exhibit 118.

Seeing none, it's marked as Exhibit 118.

(WHEREUPON, a certain document was marked Exhibit No. 118 for identification, as of 8/18/06.)

MR. AYRES: Mr. Marchetti, good morning, afternoon, whatever it is.

MR. MARCHETTI: Yeah. Good day.

HEARING OFFICER: Mr. Marchetti, did you want to give a brief summary, or did you want to go directly to the questions?

MR. MARCHETTI: We can go directly to the questions.

HEARING OFFICER: Okay.

MR. MARCHETTI: That would be a good

start.

Question 1.

MR. AYRES: Could I ask a question before he answers Questions 1?

HEARING OFFICER: Sure.

MR. AYRES: Because the decision was not listed.

HEARING OFFICER: Sure.

MR. AYRES: And that's simply -- Mr. Marchetti, are you an economist?

MR. DePRIEST: I've done graduate work in economics. And I've been doing environmental economic policy analysis for about 25 years.

MR. AYRES: Are you a member of the American Economic Association?

MR. DePRIEST: No, I'm not.

MR. AYRES: Okay.

MR. MARCHETTI: Okay?

MR. AYRES: You can go ahead, Mr. Marchetti.

MR. MARCHETTI: Okay.

On Page 4 of your testimony, you describe the control options in the Emission-Economic Modeling System model.

A, please describe the cost and operational assumptions for each of the emission control technologies listed on Page 4 of your testimony, specifically as implemented in the EEMS model analysis.

The cost and operational assumptions that were the basis into the EEMS are discussed in detail in Appendix A, mercury controls, and Appendix B, SO2, NOx control of Ed Cichanowicz's testimony. The mercury control assumptions begin on Page 55 of Ed Cichanowicz's testimony and conclude on Page 74 and assumptions defining SO2/NOx/PM controls begin on Page 75 and conclude on Page 91 of Ed Cichanowicz's testimony.

HEARING OFFICER: Mr. Marchetti, could you slow down a little bit?

MR. MARCHETTI: Oh, sure.

MR. AYRES: Maybe get the mic a little closer, it's hard to hear over here.

MR. MARCHETTI: Let me just put this over here. I will start all over.

HEARING OFFICER: For the record, when he says EEMS, it's E-E-M-S.

MR. MARCHETTI: Okay. Question A.

Please describe the cost and operational assumptions for each of the emissions control technologies listed on Page 4 of your testimony, specifically as implemented in the EEMS model analysis.

Response. The cost and operational performance assumptions that were incorporated into and discussed in detail in Appendix A, Murphy controls and Appendix B, SO2 and NOx control of Ed Cichanowicz's testimony. The mercury control assumptions begin on Page 55 of Ed Cichanowicz's testimony and conclude on Page 74. The assumptions defining SO2/NOx/PM controls begin on Page 75 and conclude on Page 91 of Ed Cichanowicz's testimony.

HEARING OFFICER: B.

MR. MARCHETTI: B. Please provide specific environmental retrofits selected by the model for each coal-generating unit in Illinois along with the associated capital and variable operating costs.

Response. We are providing the technology assignments for CAIR/CAMR and CAIR

Illinois Rule, as exhibits.

MR. ZABEL: This one (indicating)?

MR. MARCHETTI: Yes.

HEARING OFFICER: The first document is CAIR-CAMR tech. And I'll mark this as Exhibit 119, if there's no objection.

MR. AYRES: Madam Chairman, I would just note that this document, along with a number of others, was requested in our written questions. And receiving it the moment before the testimony is given makes it very difficult for us to respond to.

We would like to have the opportunity to study the document. And I'm sure we're going to get in the stream today before our opportunity to cross-examine this witness is closed.

HEARING OFFICER: Within reason, I'm willing to allow that. I would just --

MR. ZABEL: That pattern was set in Springfield, Madam Hearing Officer. Our written questions asked for documents, we did not get any in advance.

We assumed that would be the

pattern following throughout. And there was, of course, much less time to prepare these than to prepare the documents requested in the written questions used in Springfield.

HEARING OFFICER: And that's why my answer is within reason, we'll allow that.

MR. AYRES: This set of assumptions, for example, were clearly available some time ago, because these are the assumptions that were within the model, which the results of which you had, so...

MR. ZABEL: As were the IPM briefs that we asked for.

HEARING OFFICER: Let's just agree that in this proceeding there's been a lot of documents handed out at the hearing without the opportunity for either side to -- and as I said, within reason, I will allow you to cross -- will allow you some leeway on cross-examination. I loathe to ask Mr. Marchetti to come back on Monday, for example, to answer any additional questions.

So, within reason, we will try to do that. I also remind you that, certainly, any

comment you have on this information is gathered and can be filed in comments later on, if not, by the end of the process in this hearing.

MR. ZABEL: Thank you.

HEARING OFFICER: So I've now been handed CAIR-IL -- which I assume is Illinois -- Rule Tech. And if there's no objection, we'll mark this as Exhibit 120.

Seeing none, it's Exhibit 120.

(WHEREUPON, a certain document was marked Exhibit No. 120 for identification, as of 8/18/06.)

MR. MARCHETTI: However, we cannot provide capital and O&M costs for these technology assignments, other than in the aggregate. Some unit specific costs then would develop from proprietary data from individual generators, and this data was not even shared among the Illinois generators.

So what I'm saying is that we did -- in doing this analysis, we did receive some proprietary data from various generators in the state.

MR. AYRES: And can you identify which

companies that was from?

MR. MARCHETTI: Yeah. Midwest Generation, Ameren and Dynegy and Kincaid.

HEARING OFFICER: Proceed.

MR. MARCHETTI: Okay. C.

Also on Page 4, you describe the rationale for "50 Year Old Rule." Please explain what you mean by a major capital investment in this context.

What I would mean by a major capital investment are improved investments in FGD, SCR, SNCR, ACI and COPH systems installed on a coal-fired power plant.

HEARING OFFICER: Mr. Marchetti, I think, because you're looking down this way (indicating) when you read, it might be more helpful if the microphone is on the other side.

MR. MARCHETTI: This way (indicating)?

Can you hear me now?

HEARING OFFICER: Yes.

MS. MOORE: Excuse me. How many 50-year-old coal-fired plants are in Illinois?

MR. MARCHETTI: I believe we have about 51. Let me just get that number.

MR. ZABEL: I think that's a later question, but...

MS. MOORE: Is it? Okay.

MR. AYRES: I think it is later, not much later.

HEARING OFFICER: Okay. We will defer to that then.

MR. MARCHETTI: If the installation of HPAC injection systems, as described by Dr. Staudt and Mr. Nelson in their previous testimony, were all that were required for a given unit to meet the Illinois Rule, would you consider this to be a major capital investment?

"If," of course, is a critical word. And since I do not agree -- we did not agree to Mr. Staudt's and Mr. Nelson's control assumptions, because they did not take into account other unit modifications, operational constraints and performance associated with ACI, I really can't respond to that question.

Twenty-one units, okay.

HEARING OFFICER: Mr. Harley.

MR. HARLEY: In Exhibit 115, which is the prefiled testimony of Mr. William DePriest,

on Page 21, he indicates that the estimated installed cost of a sorbent injection system, such as activated carbon injection system, to be between 1.5 to $3 million per unit. Using those figures, would you consider this to be a major capital investment?

MR. MARCHETTI: Yes.

MR. HARLEY: On what basis?

MR. MARCHETTI: On the basis that, I believe, anything that's -- in terms of the capital investment of the operational control costs that go into these types of systems, adds to your generation costs. And I believe that would be a major capital investment.

Specifically, if it's going to be employed on a very small or older unit.

MR. HARLEY: Thank you.

THE VIDEOGRAPHER: Question No. 2.

MR. AYRES: I'm sorry, before we get to Question No. 2, I'd like to ask some questions about the 50 Year Rule.

HEARING OFFICER: Okay.

MR. AYRES: In the analysis that you did, you're talking about this 50-year

assumption. It's a little unclear to me, exactly what that means in terms of what the model does in 50-year old claims.

MR. MARCHETTI: Okay.

MR. AYRES: Does this mean that the units are shut down --

MR. MARCHETTI: No. No. Let me just explain this 50 Year Old Rule then.

It's a presumption we have in the model that any unit that has to face a compliance decision, if it's going to be greater than 50 years old at that time, would not receive a technology deployment, would not get retrofitted. And, basically, under a cap and trade regime, would buy allowances to meet compliance.

And we have used this 50 Year Old Rule with a number of simulations in a number of states. But not many utilities have reviewed our information, and no one has come back and said, well, I think we should get 60 years or something like that.

So I think we've had a consensus that, among the people that have reviewed our

outputs that the 50 Year Old Rule is kind of a barometer about deployment and technology. And the other, too, is that when you get units that are 55, 60 years old, and you put any kind of a major capital investment on it, you're probably going to be covering that capital -- the unit is going to have to be operating into the 65, 70-year-old range. And there's a question whether that is going to be -- if that unit is going to be economically viable with something like that.

MR. AYRES: So could you answer the question about what happens to the 50-year-old units in your model?

MR. MARCHETTI: They buy -- under a cap and trade system, they would buy allowances to remain in operation.

MR. AYRES: And under the Illinois?

MR. MARCHETTI: And the Illinois Rule, that rule is somewhat violated. And we do put technology on those older units, because you have to meet a much more stringent reduction target.

MR. AYRES: And which Illinois units

are shut down according to your model?

MR. MARCHETTI: No Illinois units are shut down.

MR. AYRES: Would they be mothballed or put out of service, or? I'm not sure of what the technical term is.

MR. MARCHETTI: There were no -- let me just repeat myself. In this particular analysis, the generation forecast can be used -- that we used in our analysis, was provided by Charles River, CRA International.

They ran a simulation CAIR/CAMR, they ran a simulation CAIR Illinois Rule. They used our control assumption as part of this analysis.

No units will shut down, okay? And no units will shut down.

MR. AYRES: Are you aware that the Tennessee Valley has already recently installed SCR and all nine units of the Kingston Plant have been put online in '54?

MR. MARCHETTI: Yes.

MR. AYRES: All right. And likewise, commitments made to the state of Massachusetts

regarding the Salem Hardwood plants, units one and two, are in service in '51 and '52?

MR. MARCHETTI: Yes.

MS. BASSI: Excuse me, what -- Mr. Marchetti just testified that his assumptions are that there would be technology added to 50-year-old plants, so what is the point of your questions?

MR. AYRES: I think he testified that it would be in some cases and not in others. And --

MS. BASSI: I don't think that's what he said.

MR. AYRES: His testimony pronounces this 50 Year Old Rule, I'm just trying to understand with it means. It's also true --

MR. ZABEL: How does that relate to Salem? Your understanding of what 50 year old means, how does it relate to Salem? I guess I lost it.

MR. AYRES: This has provided a generalization, which can be placed in this model, which assumes that plants over 50 don't do something, although I'm not exactly sure

what.

MR. MARCHETTI: They do not -- let me just clarify.

They do not deploy technology under a capital trade regime. Under CAIR or CAMR, where there's the availability of allowances to be purchased, they would not deploy the technology, they would buy allowances to do some system-wide training.

Under the Illinois Rule, because of the stringent reduction, which is significantly more stringent than CAMR, we did deploy technology on units greater than 50 years old. I think I would believe that there were like 21 units in Illinois that are greater than 50 years old in 2009.

I believe 20 of those units received technology under the Illinois Rule.

MR. AYRES: Isn't it true that models that are used for this tend to -- let me back up.

Models, like the one used by Ms. Smith, allocated reductions or buying up credits to units, simply depending on the cost

of control versus the cost of allowances?

MR. MARCHETTI: Yes.

MR. AYRES: They usually don't have a 50-year constraint, they simply look at the costs; correct? There may be some correlation, but that's not a factor?

MR. MARCHETTI: They may -- I don't know what Dr. Smith's, in terms of her modeling, in terms of what kind of presumption she has on older units. Yes, they do look at the costs of technology versus the costs of allowances, and we do the same in that manner, too.

MR. AYRES: But you added another variable.

MR. MARCHETTI: We added another -- because the model structures of NEMS, which is Dr. Smith's model, and EEMS, which is ours, I mean, you've got to switch the letters around. Ours is a much more unit-specific analysis, and you have much more unit-specific data than you would probably find in a NEMS model, a much more broader aggregate.

HEARING OFFICER: I didn't hear all that, I'm sorry.

MR. MARCHETTI: That our data in EEMS, meaning emissions, we would get out of the system is much more unit specific, whereas in the NEMS model, from what I understand there's much more aggregation in there because they do much more broader national analysis.

MR. AYRES: Could we talk a bit about that, the EEMS or EEMS model, I don't know which way to pronounce it.

MR. MARCHETTI: Sure.

MR AYRES: E-E-M-S, all capital letters. Has this model been benchmarked against other models or historical market behavior?

MR. MARCHETTI: No.

MR. AYRES: Is it in the public domain?

MR. MARCHETTI: It's -- in terms of what you mean by "public domain," has it been used in other reports or in terms of other rulemakings or?

MR. AYRES: Well, no. What I mean is the IPM model.

I guess, to some extent, the

Charles River associate models have been published, they've been available for people to comment on, make suggestions for, et cetera, for some time.

MR. MARCHETTI: Yeah. The NEMS model was first developed around 1997 and has been used in a variety of analyses, and has been discussed and used -- in going to the model, and various kinds of rulemakings, reports on various kinds of proposed rules or comments on the rules since 1997.

MR. AYRES: Are any of those public? I understand that you may have done an analysis, which related to a proposed rule, but that doesn't make your model up; does it?

MR. MARCHETTI: Well.

MR. AYRES: The public couldn't find out how you got there.

MR. MARCHETTI: It depends on what you term "public." I mean, like the ICF/IPM model is out of the public domain, the EPA uses it in a variety of other -- you know, agencies or institutions use it, but it's published in a -- they do have a little write-up, a description of

the model.

And in terms of public, it's a proprietary model. If you're asking for the computer code or something, you're not going to get it.

MR. AYRES: It has been tested against historical market behavior, though; hasn't it?

MR. MARCHETTI: I cannot answer that.

MR. AYRES: So your model is, certainly, a lot less available to the public than, say, the IPM model?

MR. MARCHETTI: Yes.

MR. AYRES: Could you please tell us the source for the cost estimates for mercury controls in your analysis?

MR. MARCHETTI: The sources of control estimates, I guess, you could find, you know, in Appendix A. For the various tables that Cichanowicz developed to develop the various kinds of control assumptions and the cost assumptions that went into an analysis.

Let me further clarify that we were provided some specific information by Midwest Gen, Dynegy, Ameren, for the control

costs, and they were -- which is that proprietary information I mentioned earlier. And that information was also incorporated into the analysis.

What we use control assumptions for, basically, is for units or utilities who do not provide us with any kind of unit-specific information.

MR. AYRES: And could you also tell us the source for the cost estimates for mercury controls that went into your analysis? You were talking about technology before.

MR. MARCHETTI: Well.

MR. AYRES: Perhaps it's the same. I don't know.

MR. MARCHETTI: It's the same. It's the same.

Basically, what I just said, for technology, would also apply for mercury control.

MR. AYRES: And you're not able to provide to us the details of either the cost or technology information that you received from the companies?

MR. MARCHETTI: That's correct.
MR. AYERS: Okay. What did Dr. Smith's model do with the data, which came from Mr. Cichanowicz, I guess, to her; is that correct?
MR. MARCHETTI: I believe she mentioned that in her testimony that she used Ed Cichanowicz's cost assumptions.
MR. AYRES: And those would be the same ones that we just talked about?
MR. MARCHETTI: Yes.
MR. AYRES: And then what did her model do with that? This is a very complex series of steps that you've gone through to produce your report, and I just want to understand.
MR. MARCHETTI: Yeah. She, basically, ran a simulation in terms of -- well, let me just back up.
In terms of Dr. Smith's -- with what she did with our -- Mr. Cichanowicz's subjects provided us with inputs, is that what you're looking for, or are you looking for some other -- something else that Dr. Smith did?

MR. AYRES: Well, I assume that -- I think you said that Dr. Cichanowicz's technology choices and cost numbers were conveyed to Ms. Smith?

MR. MARCHETTI: Yes.

MR. AYRES: And she ran a model, which she describes, generally, in her addendum.

MR. MARCHETTI: Okay.

MR. AYRES: And what was the output of that model that was then the input to your model?

MR. MARCHETTI: What Dr. Smith presented us was future generation, coal and oil gas-fired generation in the state of Illinois, on a unit-by-unit basis for a CAIR/CAMR scenario and a CAIR Illinois Rule scenario. She also presented us with future coal and gas prices, delivered gas prices, delivered coal and gas prices for Illinois units.

In this state it was from 2009 to 2020, I believe, for intermittent years. It was nine, ten, 13, 15 and 18. Those were the dates we used, so we internally could be in between.

She also provided us with future

SO2, NOx and mercury allowance prices for CAIR/CAMR and a CAIR Illinois Rule regime.

HEARING OFFICER: Excuse me. Mr. Ayres, before you go on, could we go off the record for just a second?

MR. AYRES: Sure.

(WHEREUPON, discussion was had off the record.)

HEARING OFFICER: We're back on the record.

And I would note that, the file that was a part of Mr. Marchetti's testimony is a document entitled Addendum of Anne E. Smith, Ph.D. to the testimony Krish Vijayaraghavan and James Marchetti, and that is a part of their testimony as a reference document and not a part of Dr. Smith's testimony, which she presented earlier in the week.

MR. ZABEL: But the point I think that Mr. Bonebrake was making off the record is it was a document prepared by Ms. Smith. And at the prehearing conference, which I didn't attend, so I'll let you --

MR. BONEBRAKE: And as, to which, it

was my understanding based upon our conference call before the hearing, that if there were questions for Dr. Smith pertaining to her addendum, those could be directed to her while she was present earlier this week, as well.

HEARING OFFICER: That is correct. And, to my knowledge, there were no questions directed to her directly on the addendum.

MR. BONEBRAKE: I don't recall any.

HEARING OFFICER: But that is correct, that your recollection and mine at the prehearing conference is exactly the same.

MR. ZABEL: We attached it to those testimonies because it's something that both of the other witnesses relied on.

HEARING OFFICER: Wonderful. Thank you very much.

MR. AYRES: The two documents that we received this morning, the CAIR/CAMR and the CAIR Illinois Rule Tech, those two tables, are these the output of Dr. Smith's model?

MR. MARCHETTI: No. To be honest, they are our outputs.

MR. AYRES: They're outputs from your

model?

MR. MARCHETTI: Yes.

MR. AYRES: Okay. So in what way did you use the output of her model then?

MR. ZABEL: I think he just described that. I'm happy to have him repeat it.

MR. AYRES: Okay.

MR. MARCHETTI: The only outputs of Dr. --

MR. ZABEL: Did you want him to go through that again?

MR. AYRES: No, that's fine.

MR. ZABEL: We'll save some time.

MR. AYRES: On Page 11, you state that your model predicts that 73 percent of the capacity, I believe it is, in Illinois, will install filters, meaning fabric filters, I'm assuming; is that correct?

MR. MARCHETTI: That would be filter technologies, kind of a -- for a category, would be for cold packs, halogenated cold packs and fabric filters.

MR. AYRES: But all would involve a baghouse for fabric filters?

MR. MARCHETTI: Yes.

MR. AYRES: So what you've described is then that Mr. Cichanowicz has developed technology costs and technologies, which then were entered into Ms. Smith's model to produce CAIR/CAMR prediction. And then carried over, in fact, into your model to produce your comparison of CAIR and Illinois Rule; correct?

MR. ZABEL: Just to be clear, I think what Mr. Marchetti described was Ms. Smith's model -- and correct me if I'm in error -- gave them future generation under CAMR/CAIR CAIR Illinois.

MR. AYRES: I said that.

MR. ZABEL: Okay. Well, just to be clear, what the limit of that was, is the way you phrased it.

MR. MARCHETTI: Yeah, we did not -- they didn't know CAIR/CAMR and CAIR Illinois simulations. We would not use any of their technology deploying the various inputs I described earlier.

We put them in our model and then did a compliance analysis there.

MR. AYRES: So would it be fair to say that the costs and impacts that you predict -- on the Illinois utilities that you predict, are largely determined by the technical choices and cost data supplied by Mr. Cichanowicz?

MR. MARCHETTI: Yes. As well as the unit-specific information that is provided by the various -- the utilities that I mentioned before.

MR. AYRES: Which we don't have before us?

MR. MARCHETTI: Yes.

Question 2.

HEARING OFFICER: Excuse me, Ms. Moore has a follow-up, I think.

MR. MARCHETTI: Oh, I'm sorry.

MS. MOORE: And I might need some help with this. This is something that I'm recollecting.

But with the 1990 Clean Air Act, I have this recollection that there were certain older power plants that were grandfathered, and unless they made a significant improvement, they could operate without meeting the standards.

Are you familiar with that?

MR. ZABEL: If I may, Ms. Moore, I'd be happy to -- I mean, it's more of a legal question, I think, than anything else.

MS. MOORE: Okay.

MR. ZABEL: There were certain grandfathered provisions in the 1990 amendment, they don't relate to CAIR at all. Whatever grandfathering there was in 1990 amendments, doesn't apply to any sources regulated under CAIR.

MS. MOORE: Okay.

MR. ZABEL: But they were regulated, and maybe the question you're getting at is new source reviews. But if they made certain modifications under the terms of those provisions --

MS. MOORE: Then they would have to meet standards.

MR. ZABEL: -- then they had to upgrade them.

MS. MOORE: Right.

My question is this: Are any of those plants still operating? The ones that

were grandfathered in 1990?

MR. ZABEL: Oh, yes, many of them.

Now I'm testifying. That's fact, not law.

But the fact is, you could look in the Clean Air Act, it actually lists plants in Phase I and Phase II, which were all operating in 1990. You'll find in the statute lots of plants whose names you're quite familiar with.

MS. MOORE: So the older plants that were exempted in 1990 are still operating?

MR. ZABEL: Many of them, yes.

MS. MOORE: Okay.

Do you know how many of our 50 year and older ones are still operating?

MR. AYRES: Well, if lawyers can testify -- based on what I know, almost all of them.

MS. MOORE: Thank you.

MR. ZABEL: The lawyers agree, actually.

HEARING OFFICER: Then I think the point of where Ms. Moore is actually going with it, too, with the 50 Year Rule, the legal

opinion is that CAIR doesn't apply, what about the Illinois Rule --

MR. ZABEL: No, CAIR does apply. I'm sorry.

HEARING OFFICER: Okay. I'm sorry.

MR. ZABEL: If I stated it the other way, I misstated it.

HEARING OFFICER: So the "50 Year Rule," as it's called, and I put that in quotes because that's the language that's been repeated here, those plants that were initially exempt in the 1990s are figured into the plants that are figured into this model; correct?

MR. MARCHETTI: Yes.

HEARING OFFICER: Thank you.

MR. ZABEL: Two.

Oh, I'm sorry, Doctor.

MR. GIRARD: Yeah, I've got a question then.

So, Mr. Marchetti, did you look at any of the assumptions that Anne Smith used in coming up with the price for the mercury allowances?

MR. MARCHETTI: The assumptions that

she used were based upon assumptions that Mr. Cichanowicz gave her. And it is mentioned in discussion in my testimony, and I believe in my appendix of my testimony, that the FGD cost assumptions that they used was based upon, I think, about $300 a KW for an FGD, $200 a KW for an SCR.

And I believe it also included a $35 per KW for an activated carbon system, there was a 250 megawatt activated carbon system with an SCA of 250, it was $35 a KW. Those were the control assumptions that Mr. Cichanowicz provided Dr. Smith for the simulations.

MR. GIRARD: So those are control assumptions. But how about the assumption of what it would cost you to purchase an allowance on the market under CAMR?

MR. MARCHETTI: She calculated those in her simulations. She calculated the allowance prices for both CAIR and CAMR.

MR. GIRARD: And do you think -- I mean, are the assumptions somewhere in Mr. Cichanowicz's testimony or we just don't know what they are? I'm trying to understand

how it would calculate numbers for what the theoretical mercury allowance would cost if you purchased it from another plant.

MR. MARCHETTI: Yeah. Well, the allowance prices that Dr. Smith calculated are presented here in the appendix, my appendix, Appendix A of the testimony, as well as the addendum that appears in my testimony from Dr. Smith. So those are the allowance prices that we used.

MR. GIRARD: Okay. Well, you know, I can see that, like on page -- we're looking at Page 35/35 of your testimony here, I'm looking at the addendum. But all I see is a spreadsheet with mercury in dollars per pound by year. So that's all we have, the calculations made?

MS. BASSI: The title of Table 9 on the page you're referring to, Page 39, this is from Dr. Smith's addendum to Mr. Marchetti's testimony. These are the allowance prices that were projected in her simulation, from her -- these are the allowance prices that she developed for NOx, annual NOx and SO2 and mercury.

So these are the allowance prices that he -- I'm testifying, I don't want to do that.

MR. GIRARD: No, I understand that. And that's what I'm looking at, I'm looking at that page.

But what I'm trying to find out is, whose testimony do I look in to find the assumptions that went into coming up with those values? So, I mean, there were assumptions made to be able to come up with figures to put into a model and spit out values.

MR. MARCHETTI: Yeah.

MR. GIRARD: And, you know, if I can find that in Mr. Cichanowicz's testimony and Ms. Smith's testimony --

MR. MARCHETTI: Well, the only way that it's going to refer to any kind of assumptions is the control substance to be provided. And then Dr Smith's model that takes that as one part -- is one portion of the information and plugs it in, and then she checks the allowance prices.

The model doesn't -- there are

other assumptions that go into the model, such as fuel costs, you know, dispatch order of units within a range. And so, I mean, it's, basically, who provided her with just one of the elements that was used in her projection of the allowance prices.

MR. GIRARD: Okay. So to understand it then, we would need to see how the entire model is constructed, in other words. That's what you're saying?

MR. MARCHETTI: Well, you would -- you would -- I mean, it's a projection on their part, based upon other variables besides, I believe, the -- I mean, instead of the control assumptions that we provide. I mean, control assumptions, certainly, are very critical, in terms of allowance prices, because they apply to units.

And using allowance prices, based upon their marginal cost and control, which is that last unit that's coming into compliance. And that's what -- you know, that's usually the price -- maybe that's just a price setting format, you know, for allowance price.

MR. GIRARD: Thank you.

HEARING OFFICER: Mr. Melas.

MR. MELAS: Mr. Marchetti, a slightly different matter. This 50 Year Rule that you have here, the lower paragraph, Page 4 --

MR. MARCHETTI: Yes.

MR. MELAS: -- I'm a little curious about the rule. Is that a nationally promulgated accepted rule or is that -- it says here it was MCH fields. Is this something you developed?

MR. MARCHETTI: Yeah, it's just a presumption that we've developed that we use. MCH is -- may pop up as Marchetti Chicago.

MR. MELAS: I see that.

MR. MARCHETTI: Okay.

MR. ZABEL: Would it be better to call it a rule of thumb, Mr. Marchetti? That's not a real regulation of any kind.

MR. MARCHETTI: No. It's no legal regulation. It's not been mandated in any kind of regulation about putting technology on units, under 50 or over 50 or any age.

MR. AYRES: But it is a legal rule --

well, forget the word "legal." It is a rule in your model, though, isn't it?

MR. MARCHETTI: It is a rule in our model. Specifically we use it when we use a cap and trade analysis.

MR. AYRES: And which, therefore, has an impact in determining the output of the model?

MR. MARCHETTI: Yes.

MR. AYRES: Thank you.

A slightly different topic: You testified on Page 15 that the ICFs costs tend to fall between MCH and TSD, between your costs and those of the technical support document. However, the ICF report provides very little information on their assumptions, which make it difficult to track their findings.

Have you looked at Page 24 of Dr. Smith's testimony that you include with yours, the Appendix A, where she describes CRAs, the model we'll call NEEM?

MR. MARCHETTI: Dr. Smith's testimony?

MR. AYRES: Yes. Page 24 of your testimony.

MR. MARCHETTI: Okay.

MR. ZABEL: Do you have a specific spot on this?

MR. AYRES: The bottom paragraph where she says, "NEEM is a similar model for the IPM model that is used extensively by the U.S.EPA and also has been used by the EPA in this proceeding. Both models are dynamic linear programming models of a US electricity sector. The models both minimize the present value incremental costs, subject to the set of operational constraints. The primary difference between the NEEM and IPM is in the exogenous assumptions used in the respective models, such as cost and effectiveness of control technologies, fuel prices and the electricity demand levels."

You knew that she wrote this; didn't you?

MR. MARCHETTI: I'm sorry, could you repeat?

MR. AYRES: Did you know that she wrote this?

MR. MARCHETTI: Yes.

MR. AYRES: And you knew that the IPM model was used by EPA?

MR. MARCHETTI: Yes.

MR. AYRES: And do you think Dr. Smith was clearly aware of these facts, that the ICF model was widely used and had been reviewed by many people?

MR. ZABEL: He's testified that she wrote it.

MR. AYRES: Right.

MR. ZABEL: So I think, beyond that, one can presume she knew it. But if you're asking what's in her mind, I think that's a difficult question to him.

MR. AYRES: I withdraw the question.

Didn't the ICF report describe the assumptions regarding how they capped emission levels at plants?

MR. MARCHETTI: In their analysis, they talked about their representations, yeah, how they capped emission levels at points.

MR. AYRES: And that's the way their model works; isn't it, it places caps on units?

MR. MARCHETTI: It depends on the

regulatory regime that we're looking at. If its like CAIR, where we did assign allocations for that particular regime.

In the Illinois Rule, I do have a response to a question, which I believe is No. 3, which talks about how we implemented in the Illinois Rule and how we modeled it.

MR. AYRES: That could help. ICF did it or --

MR. MARCHETTI: How we did it. I believe you just asked me how -- if we used caps, and we do.

MR. AYRES: So the ICF report described its assumptions, didn't Dr. Staudt describe his mercury control assumptions in the TSD?

MR. MARCHETTI: ICF, in terms describing your assumptions in a report, I don't believe it was clearly defined in that report that was a part of the GSD. Dr. Staudt was presented two tables at the TSD, which had controlled costs and removals and operation costs.

MR. ZABEL: In fact, if I may, Madam

Hearing Officer, I recall now going back and looking at the record, that some of the specific questions we asked of the agency concerned the input to the IPF model, but there was no witness from there tendered who could answer. We got some generality answers that the agency knew, we'd never get a table, such as this (indicating), or specifics on the model that was used.

MR. AYRES: But the report from ICF did describe their assumptions on this point; correct?

MR. MARCHETTI: They described the implementation of the Illinois Mercury Rules as best they could interpret at the time. They did not describe their control subjects.

MR. AYRES: Okay. Would those be on the EPA website, the Illinois EPA website -- I'm sorry, the U.S.EPA website?

MR. MARCHETTI: I believe they have some documentation that's called -- various years -- I think a couple of years they put out some documentation on inputs that they used in the IPM model. They can be found on a Clean Air

or Morton's division website.

MR. AYRES: Do they have cost assumptions and --

MR. MARCHETTI: They have various cost assumptions and algorithms there. Some of it is very difficult to follow.

It's not like you could go to a table and say this is the dollar per KW for a 500 megawatt unit that's burning bituminous coal and it has an emission rate of this or that. It's not that specific.

And you would have to -- sometimes you have to go read one document and then go back to a previous version of a document to get the control assumptions.

MR. AYRES: Well, it's a complex model, like the NEMS model, and so it comes up with complex outputs. But my question is about the inputs, and am I not correct, that the inputs, that model, are available?

MR. MARCHETTI: The inputs of that model are available.

MR. AYRES: And are you aware that Mr. DePriest was unwilling to provide them the

details regarding how he developed processes for Mr. Cichanowicz?

MR. BONEBRAKE: I think you're mischaracterizing his testimony, Mr. Ayers, both in writing and provided here to the Board.

MR. AYRES: I think the Board can be the judge of that.

You are aware that Mr. DePriest declined to provide information about his cost estimates yesterday?

MR. BONEBRAKE: You can clarify and say some information, Mr. Ayres, perhaps we can proceed with the question.

MR. AYRES: Some information?

MR. MARCHETTI: Yes. He mentioned that there was some confidentiality associated with some of the information that he was testifying.

MR. AYRES: And you're unable to provide some of the information that you use to develop technology assumptions for -- or that were used to develop the technology assumptions that went into your model?

MR. MARCHETTI: Yes.

MR. AYRES: Thank you.
HEARING OFFICER: Question No. 2.
MR. MARCHETTI: On Page 5, you note the "Capital and operating costs were developed based upon Illinois generators' experience in retrofitting recent SO2, NOx and mercury control technologies." Please identify the experience to which you refer, specifically with respect to the installation of mercury control technologies, and show how that experience was used to set the control cost parameters used in the EEMS model.
Several Illinois generators provided us --
HEARING OFFICER: Slow down, Mr. Marchetti.
MR. MARCHETTI: Okay.
Several --
MR. AYRES: Please speak up, it's hard to hear you over here.
MR. MARCHETTI: Okay.
Several Illinois generators provided us with unit specific capital operational cost information to retrofit SO2,

NOx and mercury control technologies. These costs were applied when considering technology choices for those specific EGUs.

Additionally, the supplied costs were used as the basis for estimating technology costs for other units in the state and did not supply specific cost information as described in Appendix A and B of Mr. Cichanowicz's testimony.

HEARING OFFICER: Question No. 3.

MR. MARCHETTI: Please explain implementation of the proposed rule in the EEMS model.

The Illinois Rule calls for EGUs to meet either a percent reduction for coal input mercury levels or an output emission standard beginning July 1st, 2009. Since the proposed rule allows for facility-wide averaging, annual plant mercury emission limits were computed for each facility, which acted as the reduction target each plant would have to achieve in compliance with the Illinois Rule.

The annual plant limits were determined by first computing annual plant limits used in two levels, percent reduction

from input fuel or emission standards based upon gross generation. The most lenient of the plant level limits was selected as the reduction for the specific plant and year.

It should be noted that the plant level limits could change from year to year based upon changes in generation. We then computed plant balances, which is the difference between future annual emissions and plant limits.

These differences were the level of mercury emissions that had to be removed to meet the reduction targets of the Illinois Rule.

A. Please describe exactly what constraints are placed on mercury emissions for each unit in the model implementation.

I believe the annual plant limits discussed above answers the question on the --

MR. AYRES: Pardon me, but you said annual what?

MR. MARCHETTI: I believe the annual plant limits discussed above -- which would be the previous question, okay -- answers the question on the Illinois Rule. However, if

you're asking about a cap and trade approach, such as CAMR, each unit receives a mercury allowance allocation as described on Page 18 of my testimony.

MR. AYRES: The question was about the Illinois Rule; wasn't it?

MR. ZABEL: I'm sorry, I couldn't hear you, Mr. Ayres.

MR. AYRES: I'm sorry.

I thought the question was that the Illinois restraints placed on mercury emissions in the Illinois model, since it's explained in the implementation in the rule in the EEMS -- the rule, proposed rule, in the EEMS model. Maybe I didn't hear it, but I didn't hear that explained.

MR. ZABEL: He said specifically that they calculated the more lenient of the two, that is, the percent reduction or the point of 0080. Okay?

MR. AYRES: All right.

MR. MARCHETTI: B. Please explain the decisions made by the model with respect to least-cost implementation of mercury controls.

To comply with plant level limits for mercury in the Illinois Rule, the different method is used to design the removal technology.

Because of a limited number of units at a facility, a maximum number of six in these cases, we are able to examine all combinations of the feasible technology options. Unit level annual costs and removals are calculated for all applicable control technologies for each unit.

The unit-technology combinations are stored in a two dimensional matrix a decision-making program goes through each set of options and totals the removals achieved to determine if a sufficient amount of mercury will be removed.

In these analyses, there are six different retrofit options along with a "no technology" option for each unit. Many of these are not applicable, such as the fluidized bed for COHPAC, steam unit.

But all combinations that are possible are explored. Each combination that yields a sufficient removal is stored and sorted

in the order of increasing cost.

Lastly, the combinations are examined, least cost option first and the proscribed combinations are thrown out. Units at each facility are assumed to avoid mixing standard carbon injection technology and halogenated carbon injection options.

Once a satisfactory mix is encountered in the order list, the units are assigned that retrofit technology or no tech and removals and costs are reported.

Another guideline in the decision is that once a unit is assigned a technology, it will not be removed or changed in a later year. In Illinois, there are a relatively unchanging limits for each facility. So the decision process starts in the first year of study, where cobenefits are the lowest and removal needs are the highest and move forward in time.

For CAMR, a cap and trade approach is used. For each unit, several technology options are assigned on a dollar per pound removal cost and a total annual cost.

Each feasible technology is

examined against the allowance price for that year. If the technology's dollar per pound removal basis is less than the allowance price or if the total annual cost after netting out excess allowances generated is less than the cost of the only allowance purchases, the technology is considered feasible. Each unit's decision is simply taking the lowest cost option among various technologies and purchasing allowances.

The same restrictions against mixing sorbents at one facility and against removing or changing installed technologies at a unit are imposed.

MR. AYRES: Are you finished?

MR. MARCHETTI: Sure.

MR. AYRES: I take it that the 50 Year Rule is also applied with respect to the calculation of the CAIR/CAMR case; is that correct?

MR. MARCHETTI: That's correct.

No. 4 --

HEARING OFFICER: If we're done with 3, I have almost 20 to 1:00, and I think we have

a different court reporter coming back this afternoon. So this is probably a good time to take a lunch break and give me an opportunity to look at the materials given out earlier.

And everybody be back in about an hour.

(WHEREUPON, a recess was had.)

STATE OF ILLINOIS)
) SS:
COUNTY OF COOK)

I, SHARON BERKERY, a Certified Shorthand Reporter of the State of Illinois, do hereby certify that I reported in shorthand the proceedings had at the hearing aforesaid, and that the foregoing is a true, complete and correct transcript of the proceedings of said hearing as appears from my stenographic notes so taken and transcribed under my personal direction.

IN WITNESS WHEREOF, I do hereunto set my hand at Chicago, Illinois, this 23rd day of August, 2006.

Certified Shorthand Reporter

C.S.R. Certificate No. 84-4327.