NUCLEAR REGULATORY COMMISSION

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In the Matter of:

BRIEFING ON PWR STEAM GENERATOR PROBLEMS

PUBLIC MEETING

DATE: December 4, 1981 PAGES: 1 thru 79

AT: Washington, D. C.

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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BRIEFING ON PWR STEAM GENERATOR PROBLEMS

PUBLIC MEETING

Room 1130

1717 H Street, N.W.

Washington, D.C.

Friday, December 4, 1981

The Commission met, pursuant to notice, at 10:00 a.m.

BEFORE:

NUNZIO PALLADINO, Chairman

VICTOR GILINSKY, Commissioner

PETER BRADFORD, Commissioner

JOHN AHEARNE, Commissioner

THOMAS ROBERTS, Commissioner

STAFF PRESENT:

HAROLD DENTON

DARRELL EISENHUT

AL HERDT

JOHN OLSHINSKY

MR. McCRACKEN

MR. MURPHY

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P R O C E E D I N G S

CHAIRMAN PALLADINO: The meeting will please come to order.

The subject of this meeting is a briefing on PWR steam generator problems. The Commission has been receiving reports on various types of problems with steam generators and the purpose of this meeting is to receive from the staff a briefing on the nature and scope of the problems and their implications.

I do not know whether any of the Commissioners have any opening remarks.

MR. DENTON: I have with me Darrell Eisenhut, who will make about a 20-minute presentation and make a response to your questions. We also plan to show a videotape made by the Florida utilities out there on steam generator replacement. And we also have John Olshinsky, who is the deputy director of the Atlanta office, and he will describe that.

I would like to start just by pointing out --

COMMISSIONER AHEARNE: Harold, during the morning I hope you address at some point one question which came to my mind. The reason I originally asked for this briefing and asked for the review is, in looking back over several years of history it seemed that about 25 percent of the PWR outage time was related to steam generator problems.

I recognize there are a variety of reasons in your paper, which lays those out. Nevertheless, I had a growing concern that if there are that many problems costing that much time, at some point it may transfer from being an economic problem to a safety problem.

It was not obvious to me that that is the way at least the industry had been looking at it, and I was not sure that that was the way we were looking at it. So some time during the morning I hope you could address that question.

MR. DENTON: I think it is a major industry problem. At least three-fourths --

COMMISSIONER AHEARNE: I recognize it is an industrial problem and I am interested in the safety side.

MR. DENTON: I would go beyond the 25 percent. I would say three-fourths of all of the PWR steam generators have had problems with the integrity of the steam generator tubes. So I think it is a very high fraction.

I think the main purpose of our review of steam generators over the years has been to assure that the integrity of the tubes were maintained. This has led to a program of plugging, inspection and replacement of steam generators.

We have not focused on trying to understand the basics, and we are always trying to understand and review in

advance the basic design, but rather to approve steam generators which look like last year's versions and had fixes for the problems which occurred last year.

I think one of the observations about steam generators is that they are such big pieces of equipment that they tend to be tested in the field. So the steam generators going into service today at Maguire, for example, were designed years ago, without the benefit of full flow testing, and the testing is being done on those for vibration problems occurring in the reactors in which they are installed today, for example.

So it could become a safety problem, and it certainly today is leading to increased personnel exposure. It averages maybe 150 man-rems just for the inspection program to keep tabs on the integrity. Replacement takes thousands of man-rems of exposure, and it is a continuous problem.

The very latest steam generators continue to show new and novel problems. It takes a lot of down time for the utilities to carry out these inspections, and our role has been focused on preserving the integrity through this program of inspection, plugging and replacement.

Darrell, why don't you respond specifically to the question.

COMMISSIONER GILINSKY: The maturity of the tubes

is certainly an important point from the standpoint of safety.

MR. DENTON: Yes, and that is why all of the attention on the inspection program. We have requirements for inspection and plugging and replacement, and it leads to personnel exposure, but that is basically the way we have been controlling the integrity of the tubes, is through frequent testing of the integrity.

Our biggest concern is not the failure of one isolated tube, because the plant is designed for such things, although you want the frequency load. It would be a catastrophic failure of a number of tubes that might lead to steam binding.

COMMISSIONER GILINSKY: It does not take an awful lot of them to cause problems.

MR. DENTON: That is right, if you had undetected degradation of the tubes, such as water hammer or seismic events or some undetected problem causing the tubes to fail further. It is fairly easy to detect one tube failing and it has happened at several reactors without incident. But our main concern has been undetected degradation such as you would get in failure of several tubes all at once unexpectedly, and compound possibly a steam line break or loss of cooling.

MR. EISENHUT: The program as set down had some

rather detailed questions in it. Those detailed questions we tried to summarize in the SECY-81-664. And what we tried to do there, as I said before, we were putting together a document ourselves summarizing the experience to date. So we tried to marry the two together rather than do a separate effort, using one for the other purpose.

The document was sent down to you was sent down in a draft form because, as you can tell, it contained an awful lot of detailed information about experience in plants. We are circulating that through and checking with each plant and being sure it is up to date and right.

It will be finalized over the next couple of weeks. What I would like to do is sort of summarize in an overview fashion some of the basic factors. The details of course, as I said, are in 664.

Could I please have the first slide.

This is just an outline of the pieces that I will try to be touching upon, just going through, and I will just be working straight down the list.

To go to the next slide, this focuses on what we already discussed. From a safety standpoint, the tubes are the primary pressure boundary. They do have requirements to have a high integrity. The way we basically do that is the tubes originally have the high integrity and we continue to ensure that they have adequate integrity by focusing on

inspections, focusing on what is going on in the steam generators.

The primers we basically change are the frequency of inspection, that is on plants that had a lot of adverse inspection. And it has gotten down to the point on some plants where we require inspections every three or four or five months.

The second piece is the scope of inspection, that is you require more detailed inspections when you do them. Ultimately you end up with either plugging the degraded tubes that are above some threshold or repairing the steam generators, either by putting in sleeves or replacing the steam generators.

The other side of that is the occupational considerations. It is resulting in considerable down time in plants. The repair costs for sleeving is a consideration to the industry. You can see these are a big ticket item. The replacement of steam generator costs are running up to the order of $300 million for the whole package.

COMMISSIONER AHEARNE: On the sleeving itself, does that solve the problem?

MR. EISENHUT: We will touch on that in a little bit. Yes, the sleeving that has been done and all of the repairs that have been done to date, following those we have not seen new problems coming up.

MR. DENTON: I guess it is too early to tell you they are not leaking in the last exam.

MR. EISENHUT: Well, as it turns out also, Sandy Hope is not the oldest one. The Palisades sleeves have now been in for three years.

COMMISSIONER AHEARNE: I was not talking about sleeving in general. I was just talking about that particularly.

MR. DENTON: I think re-sleeving was an attempt to maybe have another approach rather than a replacement. There have been four utilities which have announced plans to replace steam generators and there are probably a number of others who may be facing that choice if sleeving does not show promise.

CHAIRMAN PALLADINO: Darrell, are you going to discuss the Palisades experience with sleeving?

MR. EISENHUT: Yes. I will just mention it, and basically I think it was put in in 1978 and there has been no adverse experience since then.

CHAIRMAN PALLADINO: Has it solved their problems?

MR. EISENHUT: It has pretty much solved their problems. You will see this in just a moment when I go to the next slide. There have been different types of problems evolved over the years. One problem comes up and gets

fixed, and perhaps even the fix of the first problem, that is the basis of the second problem.

MR. DENTON: I think it is really the inability of the industry to test in any way except in an operating reactor. They don't have a test facility capable of getting these kinds of flows and chemistry, and so they build them and they hope they have solved last year's problems. And we find new ones keep cropping up.

I guess based on trends, there is no reason to think it is going away in the next few years. It is happening worldwide and not just in the United States.

MR. EISENHUT: If I could go on to the next slide, this is just a listing of some types of degradation. I don't intend to go through these. These are very complicated technical subjects when you go into each one of these. It is a very complicated type of chemistry, et cetera.

COMMISSIONER AHEARNE: And in some cases we don't understand it.

MR. DENTON: That is right, in many cases we don't understand it, certainly we the staff.

MR. EISENHUT: These phenomenon, as Harold just mentioned, have occurred worldwide. In fact, in a couple of these wastage first occurred in the early 1970's in Japan, and that is where the staff first heard of it. It was

strictly a chemical problem.

As a result of that we changed the chemistry, and some of the change in chemistry certainly perhaps led to the severity of the second problem, the second problem being of course the denting phenomenon which I briefed the Commission on a couple of times. It has a number of associated aspects of it, where they get additional corrosion of the carbon steel support plates.

There have been different forms of stress corrosion cracking. It is really stress corrosion cracking which occurred back in the late 1960's, and in the late 1960's there were tighter pH controls put on the steam generators, and that went down the line sequentially through a number of other kinds of cracking.

That is really coriou cracking. There is a type up here, and it was first, I guess, identified and pinned down in France, and it was pinned down in the lab. It is pure water. It turns out that in pure water under certain conditions, under a very tight range of parameters you can have a different kind of cracking.

So it's a very complicated technical phenomenon that's going on worldwide. There has been a considerable amount of research in the labs. There's been a number of people that are trying to understand these phenomena. I think it's fair to say that there is no clear understanding

of all these phenomena.

Just going on down the list, I will focus on a couple of these as we go through a little bit more. The erosion corrosion was a once-through steam generator problem which occurred at Oconee and it was limited to a certain number of plants.

Pitting, here, this kind of pitting, the main kind of pitting, is a new phenomenon. It's something that really came up in 1981, earlier this year, mostly. When Indian Point 3 was doing a hydro, they discovered a leak. They went in and started doing some looking at the steam generators and found that they have problems on the cold side of the steam generator. Remember, the steam generators are mostly U-tube on Westinghouse and CE. The water goes in through the loop and comes out the other side. We call them the hot side and the cold side.

And they found a number of problems. There's a lot you may see circulating, PN's, et cetera, in the last few months on this problem. We're following it very closely. Again, it's not completely understood, or it's not understood; drop the "completely."

It may be tied to some boric acid treatments that were there to limit denting. It may be tied to a number of things. There's very complicated chemistry phenomena and the industry is working on it. They are doing some

additional inspections. They had done a 100 percent inspection of the cold side and they will continue. I think it's about three or four months we're requiring another inspection at Indian Point 3.

The solution at this point really is speculation. That's my opinion.

The last problem on there was a vibration problem or vibration problems. It was called vibration wear. Historically, at plants like San Onofre there had been vibration in the upper parts of the bundles that led to problems. There has been another form of a problem which I'll mention, which the PN actually came out a couple of days ago, and that is some data from Three Mile Island 1.

Let's see, do we have a Three Mile Island slide just summarizing the results?

Why don't you skip the figure and go on to the Three Mile Island slide if you would, please.

Very recently, Three Mile Island 1 was doing some inspections at their plant and they have identified 86 leaking tubes in steam generator A and about 38 in steam generator B. This has all happened in the last couple of weeks. They expect to begin eddy current testing a couple of days from now.

COMMISSIONER ROBERTS: Excuse me. 86 out of how many?

MR. EISENHUT: There are a couple of thousand. 15,000 per steam generator. I'm sorry. There's 15,000 steam generators on B&W's and there's a couple thousand on the U types.

COMMISSIONER ROBERTS: How did they find these? How did they know there were 86 specifically there?

MR. EISENHUT: Does someone know the details? This just happened. I'm not sure we really know. The information came in by a phone call and PN in the last -- two days ago, I believe.

And the utility is -- you can go in and there are several ways you can do it.

MR. DENTON: I think they did it in helium testing. I really don't know the answer, but a typical way to do this would be helium sniffing.

COMMISSIONER ROBERTS: In other words, they could tell whether they were leaking. But to get some number such as 86 --

MR. EISENHUT: Yes, they have to either look at the tubes on the bottom, either from leaking of water, water levels, or helium sniffing.

COMMISSIONER ROBERTS: Well, it's not that important.

MR. DENTON: I don't think we have anyone that's right up to speed on that here.

MR. EISENHUT: The steam generators have been in a layup condition for some time and in the past when you lay up steam generators, when you go to restart them you find problems. It's fair to say that we're looking at this very closely. And they now have them partially drained and have them under a nitrogen blanket.

This is clearly the most extensive problem tied to layup of steam generators, if in fact that's what it is. But the inspections are due to begin next week. I only again mention it because there was a press announcement out, I think yesterday, and there is a PN out two days ago.

COMMISSIONER AHEARNE: Of course, they've been laid up about as long as any others, haven't they?

MR. EISENHUT: They've been laid up longer than any other plant has been laid up.

COMMISSIONER AHEARNE: Yes.

MR. EISENHUT: Could I go to the next slide, which is the slide on the plants, the extent of the problem. Move it over to the other side so you can see the Westinghouse line. Can you move it a little bit further?

This slide just summarizes three of the tables out of the SECY document we sent down, and we just added across the plants. There are 32 plants with steam generators that are Westinghouse designed, et cetera, down the page. About 22 out of 32, 7 out of 8, 8 out of 8, have exhibited some

form of problem.

COMMISSIONER AHEARNE: These are just the U.S. plants?

MR. EISENHUT: These are just the U.S. plants. There is a table in the SECY document that also summarizes foreign plants and foreign experience. We have -- since that data quite often runs old perhaps by a year or two, we are undertaking to send that summary to those foreign countries and asking them to update the document.

In the SECY document there's also a couple of columns that are vacant, that are empty, for example numbers of leaking tubes. We just haven't had them filled in by the time we wanted to complete the document.

The point to be made here is it's a wide variety of problems and it covers, as Harold mentioned, something on the order of 75 percent of all the plants in the U.S., that have had problems.

The other thing I should caution is, some plants which are the ones that don't have problems on this list are plants like Farley 2, Salem 2, Sequoia, North Anna 2. They're very new plants. They may well go in the other column with plants that have problems eventually.

COMMISSIONER AHEARNE: Such as McGuire.

MR. EISENHUT: Such as McGuire, which in fact on our table was not listed as a plant with a problem, only

because events have overtaken us.

CHAIRMAN PALLADINO: Wastage. I was trying to go back to your definition. It's a secondary side corrosion?

MR. EISENHUT: It's a secondary side, actually a removal of the material. The material thins and just disappears due to a chemical attack. And it is a problem that, of course, started in the center of the steam generators on the bottom, in the center on a cross layout. And it mainly was a problem that occurred back in the early 70's.

The solution to that problem was to change chemistry, and most plants changed from sodium phosphate chemical treatment to an all-volatile treatment in about late '74 or early '75. And then about a year later we started seeing the denting phenomenon.

But that problem is pretty much dormant right now. I should say, the denting phenomenon is pretty much dormant right now, too.

COMMISSIONER AHEARNE: Although I guess the St. Lucie is a wastage problem, isn't it also, except it's non-phosphate?

MR. EISENHUT: Yes, it is. And that is also one of the recent pieces of data that we're really taking a hard look at.

Now, again our thrust is not -- we're certainly

trying to understand as much as we can about it. But again, really the industry is trying to look at the problem, understand and solve it. We have consultants looking at it in some of the national labs.

But the real thrust is, we took that uncertainty into account in terms of defining the inspection intervals. If you don't have a good technical understanding of how fast the degradation is proceeding and how it is, you just have to have more frequent inspections. We define that such that the safety problems are not of paramount concern and we make it short enough to trade off against that concern.

But it becomes a major industry problem both economically and man-rem exposure, et cetera.

COMMISSIONER BRADFORD: When you say that safety problems are not the paramount concern, you're saying that the inspection program is such that they never have time to become the paramount concern?

MR. EISENHUT: That's correct. That is in fact, even to the point where on some plants we've required shutdowns on the order of two or three months.

MR. DENTON: That's the intent, is to inspect often enough so that you stay abreast of the change. At McGuire, I think something like eight or nine days of operation between inspections, for example. Once degradation is detected, we require a pretty rigorous

inspection program.

It does have a side effect of increasing exposure. So there's been no magic solution to these types of problems found on the present type of steam generators. Perhaps with entirely new materials and new design some of this could be avoided.

COMMISSIONER BRADFORD: In the cases where rupture has occurred, do they fall into any one of those problem sources?

MR. EISENHUT: Well, it's hard to say. There's only one that the tube has actually been removed following the rupture and really examined. That was the Surry plant where it was the cracking of the U-bend. Point Beach and Prairie Island events -- not Point Beach.

The Prairie Island rupture of a couple years ago was a different phenomenon, believed to be a different phenomenon, because it was in a different location in the steam generator. But I think that by and large --

COMMISSIONER BRADFORD: Different from any of these?

MR. EISENHUT: No, it would be in different columns. I'm sorry.

COMMISSIONER BRADFORD: Oh, I see.

MR. EISENHUT: They would fall in one of these different types.

COMMISSIONER BRADFORD: But they're different from each other?

MR. EISENHUT: But they're different from each other.

The biggest failure to date I believe has been -- or one of the biggest, has been the Surry U-bend cracking, for example. That's the fifth column over. It's cracking in the U-bend regions. It's a spinoff of denting where the legs of the tube get bent together on the inside row of tubes. It gets squeezed when you put it under high stresses. And they had a four and a half inch crack develop.

MR. DENTON: I would think if that were the only problem, where you didn't have to worry about more than one at a time, that probably is no more frequent than say pump seal failures, which induce small LOCA's. And it's not the individual tube that contributes to risk, but it's the fact that if several fail at one time.

COMMISSIONER AHEARNE: What about the problem if a tube severs and because of the pressure now in the tube you begin to get a whipping? Is that a concern?

MR. DENTON: If it failed more tubes.

MR. EISENHUT: Yes, that is a concern.

COMMISSIONER AHEARNE: It could now take out tubes around it?

MR. EISENHUT: You remember the Point Beach briefing we had. That was basically the concern. If the tubes -- for example, right above the tube sheet, if you postulate the phenomenon is such that it starts wearing tubes away in a big area and they're all, let's say, 95 percent worn away, so that when the first one breaks it can flail around and break the others. You can get a multiple type accident.

But again, that is a consideration that we look at in our review.

CHAIRMAN PALLADINO: But would you not know if it one broke that completely?

MR. EISENHUT: We certainly would know it, yes.

CHAIRMAN PALLADINO: Suppose you find one broken. Suppose one were to break. Would you shut down? What's the --

MR. EISENHUT: Oh, sure. We've got a hearing going on Point Beach.

CHAIRMAN PALLADINO: What's their instruction? Shut down?

MR. DENTON: I think you're asking general questions.

MR. EISENHUT: No, I understand. I forgot myself.

We do have a hearing going on on this issue on

Point Beach.

MR. DENTON: Certainly you'd know it immediately if you had a tube failure.

CHAIRMAN PALLADINO: You would shut down?

MR. DENTON: Oh, yes.

CHAIRMAN PALLADINO: What I'm getting at, you would not allow that situation to --

MR. DENTON: Oh, no, you would not. But it might persist long enough to damage other tubes.

CHAIRMAN PALLADINO: Yes, I understand.

MR. EISENHUT: There's two aspects. One of the actions we required is we put very tight tech specs on plants. Plants that have exhibited problems, we in fact tweaked the tech spec on leakage through tubes down. The lowest I remember is .3 gpm. And the thought being, before a tube breaks catastrophically you generally will see it to be a small leaker. There can of course be some catastrophic type failures, as there have been.

We require there be a plant procedure to get the plant down and shut the plant down. And we require immediate shutdown in that kind of an event. And the point is, we even require plant shutdown on some plants when the leakage exceeds .3 gpm, which is a very small -- it's down to the point where you can't really detect the leakage much below that. We require the plant to come down.

COMMISSIONER AHEARNE: So you have looked at this question, in addition to the specific on Point Beach, you have looked at this question of the possibility of a severed pipe then taking out some around it?

MR. EISENHUT: Yes.

COMMISSIONER AHEARNE: And your conclusion at the moment seems to be that the probability of that is sufficiently small?

MR. EISENHUT: Yes.

COMMISSIONER AHEARNE: Is that correct?

MR. EISENHUT: That is correct.

Does anyone want to add anything to that?

(No response.)

MR. EISENHUT: They don't have to if they don't want to.

And again, that is the very question at the Point Beach hearing.

COMMISSIONER AHEARNE: But I seem to recall, was it Rancho Seco or Oconee, they had some split-through pipes.

MR. EISENHUT: Yes.

COMMISSIONER AHEARNE: So it doesn't have to be Point Beach.

MR. EISENHUT: No. That is one of the basic questions that we have looked at now for a number of years,

is, you have to look at the failure mechanism and you have to be sure that that doesn't lead you to multiple failures, to where we've even looked at how can they move around. Can you get them moving in such a way that you can get very large flows?

But you have to also remember that when we postulate one complete offset rupture of a tube, you move two tubes apart, and they physically really can't do that. So that gets conservative by itself.

MR. DENTON: If they haven't wasted, they're pretty substantial tubing.

MR. EISENHUT: That's correct.

MR. DENTON: The thickness is 3/10 of an inch or so, if they haven't deteriorated.

MR. EISENHUT: That's right. And the inspection program is such that we believe there will generally be enough tube left from inspection to inspection that the rate of degradation will not get you there.

MR. DENTON: About 3/10, something on that order.

MR. EISENHUT: So what they do is they want to be sure that they don't, whatever the vehicle is, degrade enough.

And the other thing is, those phenomenon where you really can erode a tube, there's very few that get it circumferentially or very few that attack on all sides to

the point where you expecdt it to fail in that mode. There are only a couple of phenomena that do that.

COMMISSIONER AHEARNE: Right. But there have been a couple of cases, I thought --

MR. EISENHUT: Yes.

COMMISSIONER AHEARNE: -- in which we did find that the tube, 360 degrees.

MR. EISENHUT: Yes.

If I could go on to the next slide, this just is a summary to point out that the industry does have a major program under way in this area. These are very rough numbers. They're a little old. But the industry is putting -- is undergoing -- has a pretty major program, both in the lab -- they're removing samples, they're studying these phenomenon.

There is quite a bit of cooperation, not just in the United States but with foreign countries. And the industry is putting in a total of something on the order of $30 million a year in research on these degradation modes. Again, their biggest driving motivation I believe is more -- is as much economical, certainly, economics as safety. The impact of shutting down these plants for these fixes is very large.

CHAIRMAN PALLADINO: You said earlier, Darrell, that there was no facility for full-scale testing of any of

these generators. Is no consideration being given to that by the industry? Maybe it was you, Harold?

MR. DENTON: I think I said that because I had asked at one time and was told that the maximum flow capacity in the U.S. today was about 80 percent of full-scale flow. I don't know of any plans for this country to build it.

The practice seems to be to use in-plant experience.

MR. EISENHUT: That's right. I believe I asked the same kind of question on McGuire, were they ever flow tested at full flow. And the answer was no, it just can't be done with a full-scale steam generator.

CHAIRMAN PALLADINO: But you said they could do 80 percent?

MR. DENTON: That number sticks in my mind. I'll check it and get back to you.

CHAIRMAN PALLADINO: It seems strange to take a risk on a big plant, on all of them basically, in order to get your test data.

MR. EISENHUT: But most of these --

CHAIRMAN PALLADINO: That's like doing a dissertation on roast pig, burning down a house to find out if roast pig tastes good.

(Laughter.)

MR. EISENHUT: But most of these problems wouldn't show up in just a flow.

CHAIRMAN PALLADINO: I agree.

MR. EISENHUT: It's a chemistry that's active for years.

CHAIRMAN PALLADINO: It would have to be a very long test program even if you were trying to do it on full scale.

MR. DENTON: I think that they are very big, they are designed many years in advance, and by the time a plant gets built new information has been learned. And quite often one solution to a problem creates another problem.

For example, I understand part of the reason for having baffles in the new McGuire design was to reduce the probability of water hammer. And then the baffles begin to vibrate. So each fix they put in seems to induce still another unexpected problem.

MR. EISENHUT: All right, if I could go on, and I'd like to skip the slide on replacement and repair.

CHAIRMAN PALLADINO: Are these R&D programs on individual problems or looking at the impact of solutions from these problems? As you pointed out, solutions often lead to other problems. Are those being considered as part of it?

MR. EISENHUT: Yes, I think they are. And I think

that the PWR Owners Group as a major entity has been now in existence for a few years, and it has a pretty good-sized program under way. And I think they're looking at it in an overall sense. The program looks at all the problems.

Of course, new things will be found as new things come along. I think I told the Commission once the half-life is about a year and a half. Every year and a half there's at least one new phenomenon. It has grown somewhat shorter in recent times.

But it is a major integrated program, run under EPRI.

COMMISSIONER AHEARNE: Could I ask a question on the slide you want to skip?

MR. EISENHUT: I was going to say, I'm going to come back to it. John Olshinsky is going to cover that slide.

COMMISSIONER AHEARNE: Fine.

MR. EISENHUT: And it's going to be tied to a videotape that we have. So I'd like to move on to it.

The next slide we really already discussed. The last point I'll point out again is, there is an ALARA consideration. If you look at the entire industry as a whole, even the clean plants, you know, balance out an average, it's something on the order of 100 man-rem just to do routine maintenance inspections. Of course, plants with

problems it goes up higher and higher and higher, up to the point were you're running between 2,000 and 3,000 for extensive repairs.

The replacements at Surry and Turkey I believe we estimated on the order of 2,000 man-rem, and that's bearing out pretty well.

MR. DENTON: And the lack of waste facilities has resulted in the utilities' need to keep the steam generator on side. So the practice has been, since they can't find anyone to take it for disposal, they end up building facilities to store it there, with some level of contamination still present.

COMMISSIONER AHEARNE: But not only just the steam generator replacement. San Onofre in 1980 had 2400 man-rem, which put it number two in PWR's.

MR. EISENHUT: Right. That's what I said, it goes all the way up to the time of the problems, and the end is that order. There are other problems.

MR. DENTON: We did review some of these testing and sleeving operations from the standpoint of minimizing exposure and pushed automation to the extent to be done. But even so, it's a very messy job, even with the maximum automation, to do the eddy current testing, and especially the resleeving. They automated a large part of it, but it does result in high personnel exposure.

COMMISSIONER GILINSKY: Are you saying, then, that the steam generators are going to remain at the sites, I mean, as far as we can tell?

MR. EISENHUT: Yes. That is in fact what was the proposal and what is being done on Surry and Turkey Point, except there was one that was removed at Surry.

MR. DENTON: Well, that one was only because it went to --

MR. EISENHUT: It went to the BNL.

MR. OLSHINSKY: There are special storage buildings that have been placed there, concrete high-quality storage buildings that they're being housed in.

MR. DENTON: I didn't mean to imply that they can't be safely stored. But it's just --

COMMISSIONER GILINSKY: No, no, I understand. I mean, is there no way to clean them up and salvage the materials?

MR. EISENHUT: Not really. It was felt it was not a feasible thing to salvage it without a major facility. You'd have to ship them off to a major facility. It'd be probably a major operation by itself.

MR. DENTON: I'm sure they could be decontaminated. But they must do a cost-benefit balance, and let it sit and let decay take place for a while. And the net result of that has been proposals from most

utilities just to store them in a confined area.

COMMISSIONER GILINSKY: Would they just dispose of them if they could? In other words, they have no salvage value at all?

MR. EISENHUT: Based only on the one plant that we had this discussion with, was VEPCO. They were delighted that we were willing to take one steam generator off their hands. We required them to build a facility. We required that facility. We reviewed and approved the facility. Because it's housing low-level radiation, it has to have the radiation controls over it because it's a radiation area. I&E has to continue to keep going in and inspecting the facility.

So it would be much easier for them. They'd be happy to, based on the one piece that we have.

MR. DENTON: It's sort of early decommissioning.

COMMISSIONER GILINSKY: Is it practical to cut it up and bury it in a low-level burial?

MR. EISENHUT: I think they looked at that and there was in fact an option that was considered of doing that.

COMMISSIONER GILINSKY: Is that also too expensive?

MR. EISENHUT: I don't know what the answer was.

COMMISSIONER AHEARNE: At Turkey Point in fact

part of the hearing was specifically on that.

MR. EISENHUT: That issue.

COMMISSIONER AHEARNE: The kind of building that would be required.

MR. EISENHUT: That's right.

This slide, as I said, we've covered and discussed most of. It's points out the man-rem.

One more area I'd like to mention, and that is some recent foreign experience. This gets us to the McGuire thing --

CHAIRMAN PALLADINO: Before you leave that slide, could you answer a couple of questions on sleeving. You've indicated the sleeving that's been done so far has appeared to be successful. What does it do with regard to -- it increases the pressure drop, certainly, through --

MR. EISENHUT: Yes, a slight change there.

CHAIRMAN PALLADINO: It influences the heat transfer characteristics. Do you adjust power level as a result of that?

MR. EISENHUT: No, they've been able to go get full power out of it.

CHAIRMAN PALLADINO: Full power?

MR. EISENHUT: Because it really didn't affect that.

Do either of you --

MR. MURPHY: To the best of my knowledge, there's no significant effect on power as a result of sleeving per se. They may reduce power for other reasons.

CHAIRMAN PALLADINO: Even in San Onofre?

MR. MURPHY: Yes.

CHAIRMAN PALLADINO: But if you did a lot of it, I would expect it should require --

MR. DENTON: They're built with considerable margin.

CHAIRMAN PALLADINO: Yeah, I appreciate that. But when they plug tubes.

MR. EISENHUT: Well, I'll give you an indication on it to show why it's clearly not a problem. Plants plug tubes, and plugging tubes clearly fills up part of the flow path. They can I think plug up to 30 percent of the tubes, typically, and still reach 100 percent power. That's how much excess margin there is in steam generators.

We have in fact plants typically that have gone up to the order of 20 percent, I believe Surry and Turkey both.

CHAIRMAN PALLADINO: I thought some of them have had to reduce power because of tube plugging. I read that, I thought, in your document last night.

MR. MURPHY: Yes, 80 percent power.

MR. EISENHUT: Not directly because of the flow

problem, I believe.

CHAIRMAN PALLADINO: This was due to plugging.

MR. EISENHUT: Just due to plugging? I think it's probably at the end of the cycle if they were. You can get generally to 20 percent.

It's probably -- is it covered by ECCS?

MR. MURPHY: I don't believe that power has been reduced as a direct result of plugging. Power has been reduced to slow down corrosion rates and for other similar reasons.

MR. DENTON: It certainly could lead to it.

MR. OLSHINKSY: It has been reduced because of this pitting problem referred to earlier, to reduce or change the temperatures where we had the cold leg pitting.

MR. EISENHUT: That's right.

MR. OLSHINSKY: So there were some changes in power level due to that.

MR. EISENHUT: And there's been changes in modes of operation. But it's more -- it's not a direct result, I believe.

CHAIRMAN PALLADINO: And I gather when they do the sleeving they do pressurizing so that you get a contact between the two walls?

MR. EISENHUT: Yes, sir. You seal it and you raise it at the top and the bottom.

CHAIRMAN PALLADINO: Yes. But still, you'd like to get a direct metal to metal contact all the way along.

MR. EISENHUT: As close as you certainly can, yes.

CHAIRMAN PALLADINO: All right.

MR. EISENHUT: Could I go to the next slide.

I'm really here only going to focus on the last piece of this. As we mentioned, there's been considerable foreign experience. This is an area we've been working closely with a number of the foreign countries now for at least the last six years, because some of the problems are exhibiting themselves there as well as here. In fact, sometimes they're first.

Recently, in the last couple of months, we've had communications that there was a problem at the Ringhals 3 plant in Sweden. It was a most recent problem. That problem very shortly thereafter we found out also was occurring at Almarez in Spain.

The problem was identified as being associated with Westinghouse Model D steam generators.

If I could have the next slide, I'll just -- this is probably a little too much detail. The only significant difference between these plants and the plants that we've been talking about before is in the bottom of the steam generator they have what's called a reheater section. They

get a couple of more percent efficiency out of the steam generators. They have a different flow path. They put in these baffles and they just put in different support plates, support structure.

The plants in the United States that this would first exhibit itself on are shown on the next slide, and the first plant to use Model D steam generators in the Unites States is McGuire. As a result, I believe the sequence was that the problem was found in Ringhals in Sweden; as a result of that Westinghouse recommended that the Spanish reactor shut down and do an inspection, which they did, and found a problem.

Also as a result of that they made a recommendation to McGuire to, which was still coming up doing testing, to do an examination. McGuire has recently finished some examinations. On the very next slide it sort of summarizes basically where we are on this. We're closely following it.

They've done some limited look in the one steam generator and they've found no indications. They've since gone up for a couple of day test up to on the order of 75 percent power, instrumented on this one steam generator to see whether they could see vibration of the tubes, because it's believed to be a flow vibration problem.

They did in fact detect that the tubes hit

resonance peaks between 63 and 68 percent power.

MR. DENTON: It's my understanding that in Sweden they found over 100 tubes damaged, and it's the outer row. So there may be 300 tubes potentially involved.

One aspect of this problem is it can be detected by acoustic monitors outside the pressure vessel when vibration begins to occur, and then at McGuire they're actually attaching instrumentation inside some of the tubes to get a correlation between the outside noise and the inside.

And the problem can be repaired by going in through a feedwater heater. So I envision that the repairs will be done on McGuire as soon as its test program that it has outlined is completed to determine what repairs might be suitable.

COMMISSIONER AHEARNE: Is it correct -- I seem to recall for both the Ringhals plant and the Spanish plant that it's a damage that was occurring after only about 400 days or so of power operation?

MR. EISENHUT: Yes.

COMMISSIONER AHEARNE: And that it was about -- perhaps the tubes were 50 percent through wall?

MR. EISENHUT: Yes. I apologize, I missed my note here. We slipped by that.

It is 100 tubes on the edge. It is that after

some six months of operation, tied to the actual, how much flow they had, they found quite a bit of damage. They actually have two data points in time at Ringhals and they found that as a general rule of thumb -- I asked Westinghouse, is it appropriate to say that the depth of degradation doubled in six months from like 20 to 40 percent and the numbers of tubes doubled in six months? The only point being it's a rapidly proceeding phenomenon.

COMMISSIONER AHEARNE: Yes.

MR. EISENHUT: And that's why we were so closely monitoring McGuire.

CHAIRMAN PALLADINO: Is it primarily in the preheat section?

MR. EISENHUT: It's primarily in the preheat section on this one side, as Harold mentioned, right where the flow comes in.

MR. DENTON: Well, they've determined flow velocities are 20 feet a second or so in that area, and it incites vibration of this baffle plate, which directly then wears on it.

MR. EISENHUT: That's right. And late December and some time in January they will be installing these internal monitors.

MR. DENTON: So I think since it can be detected our goal in McGuire is to prevent any further degradation,

but at the same time run sufficient tests to pin down where it occurs so that modifications can be determined. I think the kinds of things we're talking about in the way of modifications are change the design of the flow restricter in the feedwater line, which determines some of the flow patterns, there are some impingement baffles we are considering changing to alter the velocity, and finally stiffening, perhaps, of those, and maybe even others.

But the program at McGuire is to run, as I recall, eight or nine days at a time.

MR. EISENHUT: Yes.

MR. DENTON: And then shut down and then re-examine, re-inspect, and install more instruments. And it's really an investigatory program. And we are preventing further degradation from occurring there, but at the same time gaining the data needed to make repairs.

MR. EISENHUT: The last slide just is a listing to show that this is a problem that's not just the United States. There's just a listing of the foreign plants that we're aware of and the related commercial operation dates. Crisco in Yugoslavia we understand is not going to be able to start in 1981.

The two that have started, Ringhals and Almaraz, we have been in contact with the licensing authorities in both of those countries, and in fact next week we'll be

meeting here with the Spanish authorities.

The next pant to come up is Unger 1 in Brazil, which is due to be starting early, very early in '82. And we've been asked to participate in a joint meeting of the Swedish, the Spanish, the Brazilians and the U.S. under the auspices of the IAEA, is actually having the meeting some time in January.

With all these plants coming down the line, it's something that we really need to be right on.

CHAIRMAN PALLADINO: Harold or Darrell, does stiffening these tubes help on the spreading problem or not -- or on the vibration problem?

MR. DENTON: My knowledge doesn't extend beyond what I've said about it. I know that stiffening of the baffles has been discussed. Now, I haven't heard Westinghouse discuss stiffening the tubes themselves. I guess that would alter the damping.

MR. EISENHUT: Well, I think the verdict's still out yet. If the tubes are vibrating or if the plate's vibrating against the tube -- you know, you have to look at what the phenomenon is. If it's a tube vibrating, certainly stiffening it would change the resonances of the tube. If it's a plate banging into a tube, if the tube is twice as thick it may still wear away pretty fast.

So I think that it's a question that we've asked

and I just think there's not enough data to know whether that would be a good solution or not.

MR. DENTON: It's obviously one that's got to be made sooner rather than later, to avoid personnel exposure and to avoid wear and rupture of the tubes. So I think in my conversations with all parties involved the objective has been to not let degradation proceed beyond where it is. That's been the objective in the foreign countries.

CHAIRMAN PALLADINO: I was thinking that stiffening the tubes has a number of impacts. One is vibration. Another one is that because they're stiffer you might have less stress corrosion cracking, that it would be reducing the stresses. And since sleeving seems such a -- has some potential, maybe stiffening them in the first place would help.

I don't know if anybody is looking at just making a thicker tube.

MR. EISENHUT: It may have a negative side, too, and that is when you put a sleeve in you've introduced a beautiful crevice.

CHAIRMAN PALLADINO: Oh, I know. That's why I'm saying, rather than sleeving why not start with making thicker tubes. And it may have a favorable impact both on stress corrosion and on vibration. But I don't know.

MR. DENTON: I'll check that out and get back to

you. I haven't heard it actively discussed.

MR. EISENHUT: All right, that completed everything we were going to say except the slide on replacement and sleeving. So could I go back to that slide on the status of replacement and sleeving. And John Olshinsky from our Atlanta office will be addressing that.

MR. OLSHINSKY: I'll be discussing the replacement process at Surry and Turkey Point, not the sleeving process.

I'm the Director of Engineering and Technical Inspection for Region II, and accompanying me from Region II is Al Herdt, who is the Chief of the Materials and Process Section in my division.

Replacements at Surry took place in '79 and '80 and have been completed. At Turkey Point 3 steam generator replacement is ongoing, scheduled to be completed, the actual replacement of the steam generator itself about February of '82, with the outage being complete, scheduled to be complete in April of '82.

Both Surry and Turkey Point are two-unit three-loop Westinghouse plants. The reason we wanted to brief the Commission on the replacement process is because of the size of the undertaking. It's been normally taking nine to ten months. It involves a great number of workers, on the order of 3,000 to 4,000 usually, and expends about

2,000 man-rem of exposure per unit.

The size of the job requires extensive preplanning and thorough management controls.

COMMISSIONER AHEARNE: John, is the number -- you said 3,000, 4000. Now, is the number because they have to cycle through a lot of people?

MR. OLSHINSKY: They cycle through a lot of people, for one thing. And there are a lot of support activities going on besides the people working directly on the steam generators. So they actually see an increase in work force of those type of numbers. It's a very, very large project.

MR. DENTON: The plants are not designed for ease of steam generator removal. Some of the early AEC plants, I recall, had steam generators mounted on carriages to facilitate removal. But the trend turned into not providing for steam generator removal in this country.

MR. OLSHINSKY: You'll see some of the process going on. My discussion will be just a slight discussion of the process and then show you a videotape of the process at Surry and Turkey Point, which we've edited down fairly short. I'll narrate portions of that.

We also provided, as a result of our inspection activities at various plants in Region II and during the replacement, we've provided part of the information support

supplied to you that dealt with exposure, ALARA techniques, and replacement process, as well as the operations history at Surry and Turkey Point, the operating history.

Each unit, as far as the replacement is concerned, is shut down and defueled and then the reactor vessel head is reinstalled. The replacement process includes removal of the upper assembly of the steam generator, which has the moisture separators, and those remain in containment and those are refurbished and partially replaced. And then the lower assembly is removed and replaced completely.

We have noticed a significant improvement, I think, in technique as the units have gone on. The first unit to replace steam generators was Surry Unit 2. During that replacement the overall exposure was 2,140 man-rem, which was about four percent over the Licensee's projected estimates for that project.

Surry Unit 1, which was the follow-on replacement, expended about 1759 man-rem, which about 15 percent under the projection. Now, there are various reasons for that improvement. They include changes in work scope and better dose estimations the second time around.

But we also believe that there is a significant increase in the learning curve and techniques. They used videotapes of the first unit replacement for better training and preparation for the second unit replacement. They

decided on the second unit to provide new reactor coolant piping as opposed to refurbishing old piping, and that saved exposure as well. So we have seen improvements.

We think that improvements carrying over to Turkey Point from what we've seen so far also -- there have been discussions and exchanges of technology between Turkey Point and Surry. Turkey Point personnel observed the operation at Surry. They're going to use some equipment at Turkey Point that was used at Surrey, and there have been quite a few discussions as far as the radiological aspects as well of limiting exposure during the process.

To date at Turkey Point they have expended -- well, not to date. But they have expended 1110 man-rem as of November 30th of this year, which is about 52 percent of the projected total. They have about -- they have completed about 60 percent of their activities, and right now the actual exposures they have are running about 30 percent below the projected estimates for the work they've done. So we think there is an increase in the learnint curve as they've gone through.

COMMISSIONER AHEARNE: Is that sharing of information being done on the basis of individual utility to individual utility, or is there any more general industry approach to try to retain that information?

MR. OLSHINSKY: I'm not sure. To my knowledge it

was individual utility to individual utility, and we do have -- there are some other utilities observing the replacement techniques at Turkey Point now.

COMMISSIONER AHEARNE: So as long as there is at least one utility that has to face a steam generator replacement, they can keep passing information along?

MR. OLSHINSKY: Well, they've shown an improvement throughout the process. We certainly don't want to lose the information.

As these major activities have taken place, we've also increased the scope and frequency of our inspections as well. The scope has been especially increased during the replacements at Surry and at Turkey Point in the area of radiological, welding and materials areas.

I think it's significant to note that throughout the Surry process and throughout the Turkey Point process to date no escalated enforcement actions have been taken and no worker has received over the allowable radiation exposure limits, even though it's a very major program.

We have some carryover, too. I'd like to note that inspectors from other regions also participated in the inspections at Surry while they were ongoing.

Before we show the videotape, I'd like to point out a basic difference in the replacement at the two plants. At Surry -- well, at both plants, as I mentioned,

the moisture separators were removed and refurbished. At Surry the cut was made in the reactor coolant piping and the entire remainder of the steam generator was removed from containment and replaced.

At Turkey Point, instead of cutting the reactor coolant piping, the cut was made in the steam generator wall itself, leaving the lower channel intact, the primary head intact. The cut was made just below the tube sheet. It was this portion of the steam generator that was removed and is now being replaced.

As we show the videotape, one thing I'd like to mention is I'd like to thank VEPCO for use of their training tapes. The first portion of the videotape is a portion of a more extensive tape that was put together by VEPCO for training, for worker training during the replacement process.

The second portion of the videotape we'd like to thank Florida Power and Light for allowing us to use the film. It's an unedited, unnarrated, unfinished tape. They're compiling the tape, editing it right now in order to be able to use for training purposes at Turkey Point, and I'll provide comments as needed or desired during that portion of the tape.

VIDEOTAPE: This program has been produced to provide a documentary description of the steam generator

replacement project at Surry Power Station Unit No. 2. In addition, this tape and the raw tape footage and the 35 millimeter slides taken during the replacement outage will be utilized as a valuable training aid for the workers who will perform the repair effort on Surry Unit No. 1 in the near future.

The steam generator repair program is intended to restore the steam generators to a new condition. This has been necessitated by the continuous degradation of the steam generator tubing. This degradation has been caused by thinning and denting of the steam generator tubing. These corrosion-related phenomena result in a reduction of the tube wall thickness, reduction of the tube diameter, cracking of the steam generator tubes, degradation of the tube support plates, and other related degradation.

These phenomena, as well as their cause and consequences, have been well documented in the technical literature and submittals to the NRC by VEPCO and other utilities and the nuclear steam supply system manufacturer. For that reason, this will not be described in great detail in this film.

The basic approach to the repair of the steam generators will be to completely replace the lower shell assembly, that is that portion of the steam generator below the transition cone. The following animated sequence will

show the methodology that was used.

First, the main steam piping and feedwater piping are disconnected from the steam generator.

The Pulmer crane is attached to the upper shell and the steam generator is cut on the transition cone just below the upper girth weld. The upper shell is then lifted away from the lower shell, leaving behind part of the moisture separatio equipment. The upper shell is then rerigged and inverted as shown.

MR. OLSHINSKY: That portion of the assembly weighs about 90 tons at Turkey Point, 90 tons.

VIDEOTAPE: After the inversion, it is set in a storage stand where new moisture separation equipment and a new feed ring are installed.

A cap is then welded on the top of the steam generator. The reactor coolant pipe is then cut and removed.

Next, the water is drained from the secondary side of the steam generator, which has been utilized as a shield. Then the Pulmer crane crane is rigged to the lower assembly using the swivel lift beam. The steam generator supports are discarded and the steam generator is lifted vertically out of the steam generator cubicle.

An up-ending shoe is then attached and the steam generator is laid down to a horizontal position.

Next, the steam generator is picked up in a horizontal position and turned 180 degrees, so that it will be going out of the containment transition cone first. It is then winched out of the containment.

MR. OLSHINSKY: The reason it's turned 180 degrees is in order to minimize interference with the amount of concrete that had to be removed from the area around the equipment access hatch before it was removed.

VIDEOTAPE: From here, it is lifted off the equipment hatch platform onto a transport vehicle and removed to an onsite storage facility.

The new steam generator lower assemblies are brought into the containment in reverse order of removal. The assembly is winched into the containment, turned 180 degrees, and up-ended on the up-ending shoe.

Then it is moved into position and lowered into the steam generator cubicle. The old upper shell is then re-inverted, mated up with the new lower shell, and welded back together.

MR. OLSHINSKY: Okay. Now we're into Turkey Point. That's Unit 3 on the left. That's the view up the containment and the steam generator. The grinding on the steam generator supports which you'll be seeing here is the preparatory grinding, and the torch work there is actually going on outside containment before the replacement process

takes place.

What they're doing there is they're in-prepping on the new steam generator portion. That's where the actual cut is made, and that's in-prepping of feedwater piping that's replaced.

The top of the steam generator, that was the dome. The moisture separator has already been removed. You see a support ring and you're looking at the steam generator cubicle walls. Now, what that is is the alignment chain for the tungsten-carbide saw mechanism which they use to cut through the steam generator shell itself.

MR. EISENHUT: As John mentioned earlier, here they cut that bottom little piece of the cone, half of the cone, and leave it. So the piping still is attached to it.

MR. OLSHINSKY: So you see them making this cut. Now, the primary side will remain. They've already previous to this cut through access ports, cut the primary baffle plate or divider plate which attaches to the steam generator tube sheet. That's already taken place.

And now this process is actually cutting the shell of the steam generator just below the tube sheet. They use a saw to cut this shell on the A steam generator. They used a plasma arc torch, which they found to be significantly quicker for cutting the B and C steam generator shells.

That saw mechanism cutting through actually took

about 21 shifts. It really wasn't expected to take that long. They had some problems with the saw and some breakdowns of equipment. That's really why they went to the torch.

The torch, on the last unit, they actually got it down to just a little over two shifts.

What you see here is a tent enclosure that's down in the area of the cut. The cut and the reactor coolant piping are actually inside the tent. The tent was used, put up and used to minimize the spread of contamination. There is also shielding in the tent to minimize the exposure.

Now you're going to be seeing some of the rigging. During the cut, of course, they were relieving some of the weight of the steam generator with the hoist, with the crane. And you see the rigging, and it'll go up to the swivel lift beam that was pointed out in the Surrey film.

That's the beam, and then the remainder of the rigging up to the crane hoist.

And that's a view of the channel cut with the lower assembly being lifted slightly at this point.

CHAIRMAN PALLADINO: This is where they have to make two circumferential welds in there to close it up?

MR. OLSHINSKY: It would be one at the top and one at the bottom, yes, sir.

Now, what the workers are getting ready to do in this portion, you'll see them go in and they'll be installing a herculite cover on the bottom of the portion that's getting ready to be removed and over the top of the channel head bowl area that remains, which is the primary portion there.

The purpose of putting the herculite in was to minimize the spread of contamination. It was very well-rehearsed. You'll see them spend -- I guess it shows the entire process there. They spent about three and a half to four minutes doing this. It's been rehearsed many times and preplanned because with that vessel lifted like that the doses are in the order of 9 R per hour in that area right now. So it had to be a very quick process.

While that's going on, as you watch that process going on, I'd like to mention some additional facts on the steam generators at Surry and Turkey Point. They are slightly different. The Surry steam generator is a model 51, which is slightly larger, had a different support process, too, had about 100 more tubes than the model 44 at Turkey Point.

To give you some idea of the physical dimensions and sizes of the pieces of equipment that are moving, that lower assembly weight, which is the portion that's being prepared for removal right now, it was about 205 tons at

Turkey Point, 250 tons at Surry.

The polar crane capacity had to be upgraded as a result of moving this up to 225 tons at Turkey Point. The height of the generator is about 63 feet at Turkey Point and its width is about 10-1/2 feet, and it was slightly larger than that at Surry.

Now, in addition to the replacement of the steam generator lower assembly, this portion including the tubes and tube sheet, there was a number of modifications that have been incorporated in the replacement steam generators. They have added a baffle plate in the tube sheet area which is to provide lateral flow over the tube sheet to minimize sludge buildup; got an improved blowdown system.

The tube support material has been changed to stainless steel in the replacement steam generators, 405 stainless. Additional access ports have been added for inspection and sludge lancing, and the condensate cleaning and polishing system has been upgraded as well.

So there are some changes, significant changes in the replacement generators.

(Pause.)

CHAIRMAN PALLADINO: How do they prepare the weld cavity, the weld surface, for rewelding that circumferential weld?

MR. OLSHINSKY: For rewelding, the prep, it was

machined. You saw them machining the new ones coming on, and they machine prep this area where the channel head joins to it.

CHAIRMAN PALLADINO: How do they -- do they get some machine down there to do the machining?

MR. OLSHINSKY: Yes. Is this basically the same machine, Al, as they used for in-prepping?

MR. HERDT: For the in-prepping.

MR. OLSHINSKY: It's essentially the identical machine or the same machine that you saw earlier in the film, that they were using for in-prepping the new portion of the steam generator. They actually put that in place and in-prep it.

CHAIRMAN PALLADINO: They put that down there?

MR. OLSHINSKY: Yes, sir.

Now they've lifted it up. You'll see what's on the bottom there, is the remaining channel head bowl area, which is the primary portion. And this is a view of the steam generator cubicle, and you'll see it lifted up. And they're in the process of removing the upper support ring. The ring is keyed and bolted into position. Yes, it has to go. They can't lift it.

You see them using a precision tool appropriate to the size of the size of the equipment.

(Laughter.)

(Pause.)

MR. OLSHINSKY: They're swinging the ring out of the way and continuing with the lift.

What they're doing is they're actually changing some of the lift points to different grunions so that they'll be able, once they lift it, to be able to swing it in place.

(Pause.)

CHAIRMAN PALLADINO: In replacing the steam generator, do they have confidence that they've got a better generator? Is there some change between the one that they take out and the one they put in?

MR. OLSHINSKY: Yes, sir. Well, I had mentioned some of the changes that they had made. And there was a recent inspection that had been made at Surry which I was going to mention at the end of what they had seen so far after 15 months in operation at Surry. So they do have confidence that they have corrected many of the problems.

That's the top of the shield wall that they will lift over and clear. They thought they were going to have to remove that, and then they evaluated and figured out that they had a few inches clearance. And you'll see as it gets over it's only a few inches clearance, on the order of three to five inches.

CHAIRMAN PALLADINO: If they think they can

correct it by replacing portions of the steam generator, why don't they build the new ones with those corrections already in place?

MR. OLSHINSKY: I think that's part of the -- I think the new ones are. It's just, as Darrell had mentioned earlier, that the generators had been constructed. Even these Model D's, which are really the latest ones as far as operations go, I think for many plants many years down the line those have already been constructed. So it's a very long lead time.

CHAIRMAN PALLADINO: But even though they've constructed them, why don't they, if they're eventually going to have to do this in the field, why don't they fix them up before they ever leave the shop?

MR. EISENHUT: Well, a lot of it's more than -- it's more than they've just been constructed. A lot of them are delivered in the plants. Remember, this goes in pretty early.

COMMISSIONER AHEARNE: And a number of your plants have water chemistry problems.

CHAIRMAN PALLADINO: I know, but that's why I asked them, have they really solved the problmems.

MR. EISENHUT: Well, on water chemistry they switched from carbon steel to stainless steel support plates.

CHAIRMAN PALLADINO: Well, what I was getting at, you're going through a lot of effort here to make a change. Why not make the change early? I'm not saying -- I don't know whether the change is as effective as we'd like it to be, but to the extent that it is it would be better to do it early than do it in these kind of circumstances.

MR. OLSHINSKY: Yes, I would agree. I assume that's under evaluation. And I'd like to say some of the changes were those that had been talked about before. For instance, the change to stainless steel support plates is to help eliminate the denting problem which has been --

MR. DENTON: Another factor, Westinghouse has announced their intention to close their Tampa facility because they've essentially manufactured all the steam generators for which they have sales. So the capability to manufacture new ones would be in question very shortly.

COMMISSIONER AHEARNE: If they do close, is there any place -- are there any existing facilities in the world that can build the steam generators?

MR. DENTON: Since other countries are still supplying them, the answer must be yes. I think Westinghouse was strictly on an economic; they had made all the ones for which they have customers.

MR. OLSHINSKY: There are CE facilities, B&W facilities.

They're swinging past the shield wall now and they'll be lowering it. And what they do is, they lower it onto what they call a lower shield plate. It will be welded in place.

While the process is going on of the welding, the plate area on contact was about 250 MR per hour, and general area was about 60 MR per hour during this process. Just for information purposes, the radiation levels on the steam generator shell itself are on the order of 100 MR per hour at the highest point on the outside of the shell, which equated to about 35 MR per hour at ten feet, and then 60 feet away it was down to one MR per hour. So it was fairly low after that, after they got the shield plates in place.

COMMISSIONER AHEARNE: Now, did both of these -- given some of the problems they had at San Onofre, did both of these use a lot of contract labor?

MR. OLSHINSKY: Yes, sir.

And that's the welding of the lower shield plating. And basically, once those were welded in place, they were removed and taken off and stored basically in that condition.

CHAIRMAN PALLADINO: What organization actually contracted to do this? Was it the steam generator supplier?

MR. OLSHINSKY: On the cutting and the removal

itself?

MR. MURPHY: Chicago Bridge & Iron, are the ones that did it mostly at Turkey Point.

COMMISSIONER AHEARNE: Did they also do Surry?

MR. MURPHY: Yes, I think they had some CB&I people at Surry. I don't think -- yeah, I think they did the welding at Surry. Daniels did a lot of work up there also.

MR. OLSHINSKY: Now they're getting it in position. They've got the plate on and they'll be lifting it back up in order to put on the up-ending shoe, which was pointed out in the Surry film. That's the blue device there on the right-hand side of the screen, and that'll actually be bolted to the steam generator.

And after they bolt it they'll be lowering the generator off the operating floor down to the area equipment access hatch, and they have a rail system to facilitate movement through the hatch and you'll see the movement through the hatch. And you'll see some portions right outside the hatch, where some of the shield wall and concrete had been removed.

Now, at both Surry and Turkey Point they had to reinforce the operations floor before going through with this process. Clearance at Surry when they were removing the steam generator was about an inch and a half

diametrical. On Turkey Point through the hatch, at Turkey Point it's about six to eight inches.

There was an extensive pre-op program after they completed the operation at Surry and there will be at Turkey Point. At Surry it was on the order of three months. It was basically a modified startup program, in which they went through a number of system checkouts and hydros in accordance with the ASME code.

(Pause.)

MR. OLSHINSKY: One thing I'd like to mention as the film is concluding, at Surry 2 last week, after approximately 15 months of operation at Surry 2 with the original steam generator replacement, eddy current testing was conducted on approximately 600 tubes in each of two steam generators, with no indications of defective tubes. So that's our basic first real feedback on the replacement program.

And there had been some shield wall and concrete removed in this area that you see here.

(Pause.)

MR. OLSHINSKY: That gives you some idea.

That concludes my portion of the presentation.

MR. DENTON: I don't know if we've answered your original question, Commissioner. It's certainly a large financial incentive. The safety impact of our inspections

leads to these financial incentives when we require inspections and replacements.

COMMISSIONER AHEARNE: I had no doubt that there was a significant economic interest on the part of the companies. Clearly, when you look at the outage times and then the replacement costs, it's very significant.

My concern was whether we were seeing it as a potential serious safety problem in the sense that any time that you've got a piece of equipment that is running into that number of problems, that frequent number of problems, particularly when you think you've solved it and then another one comes up and you solve that, and then another one comes up, I think you have to begin to get a little uneasy about it.

MR. DENTON: My sense is people were more optimistic a few years ago about diagnosing the problems than they are today. There's a certain acceptance today that replacement may become a way of life and that they may not be good for 40 years without really drastic overhaul in their design and materials.

COMMISSIONER BRADFORD: Darrell, let me ask you, if a steam generator tube does rupture, start with just one anyway, what does the operator see? What -- how does he know that that's what's happened?

MR. OLSHINSKY: He starts to -- I was trying to

recall our worst case rupture, the double-ended separation. He actually sees depressurization taking place, with a number of alarms in the secondary system, radiation alarms occurring at that point. It's basically a depressurization transient is what he sees taking place.

COMMISSIONER BRADFORD: What does he have to do and how quickly does he have to do it?

MR. OLSHINSKY: He'd go into a rapid shutdown and cool down and depressurize. You're going to continue to leak until you get the plant depressurized, cooled down and depressurized. The leak will continue throughout the process. So it'll take a while to get down and depressurize.

But the leak of course will be decreasing over time as you are decreasing pressure. So you'd have to actually decrease pressure and cool down.

CHAIRMAN PALLADINO: Before he can isolate the secondary side?

MR. OLSHINSKY: That will isolate the secondary side, but you'll still be leaking from primary to secondary. You'll trip and stop steam to the condenser right away. That'll be part of the process. But the leak itself won't stop. You'll actually continue to go into the secondary side with the primary until you actually get the plant cooled down.

MR. EISENHUT: But if this primary side is hung up at 1,000 psi higher, the idea is you have to bring down -- you don't wnt to get it so that the primary is lower than the secondary. So you bring primary down to essentially secondary and then bring them down together.

COMMISSIONER BRADFORD: What I'm really asking, is this the kind of situation in which the operator has to do a number of things fairly quickly?

MR. EISENHUT: He has to do a few things. It's not very rapid.

MR. DENTON: It's a small LOCA and I don't think it's that much more difficult for the operator than any other.

MR. OLSHINSKY: It's not really that different from other emergency procedures. It's an emergency procedure, it's one they train on, and it's not significantly different than other emergency procedures, not any more complex than others or less so.

COMMISSIONER BRADFORD: Do we test on that?

MR. OLSHINSKY: Do we test on it?

COMMISSIONER BRADFORD: Yeah.

MR. OLSHINSKY: During the licensing process, that would be one of the emergency -- I would assume that that is one of the emergency procedures and during licensing testing they cover a gamut of emergency procedures and I would

assume that that's one of them.

MR. EISENHUT: I don't know whether it is in every case.

MR. OLSHINSKY: I think they audit. You know, they don't ask the same emergency procedures on every case. They test people on emergency procedures and that's one of many.

MR. EISENHUT: I think with plants where we really had the concern one of the things we insisted upon was that te operators get retrained on that procedure. And I remember when we actually had the leak at Prairie Island a couple of years ago, one of the first things we asked the utility was, are you following that steam generator procedure right down the line.

COMMISSIONER BRADFORD: Is the thing that distinguishes this from other small LOCA's the rise in radiation readings on the secondary side? Is that how he knows it's a steam generator tube rather than, say, a pump seal?

MR. EISENHUT: Yes.

MR. DENTON: That is, right where the flow is high in that one area.

MR. EISENHUT: The only operating plant in the United States with that is McGuire.

MR. DENTON: Is McGuire. And as noted here, they

went up, they came down. They're now shut down. They're due to restart again --

COMMISSIONER BRADFORD: That's going through the steam generators, as distinguished from somewhere else?

MR. EISENHUT: That's doing a mass balance and I'm not --

Mr. McCRACKEN: When you get a small leak like that, they have a requirement for radiation monitors on continuous blowdown on the steam generator, plus periodic sampling. And when you get a very small leak, they'll notice the difference in activity over a period of samples from one time to the next time. That gives them an indication they have a leak, and in many cases what they then do is start concentrating samples to get a better indication of how much it is when you're in those low ranges.

For a larger leak, almost instantaneously you'll see an alarm on your air rejecter discharge from the condenser, which is where most of your noncondensible gases come from, and any leak over three-tenths, four or five-tenths of a gallon per minute, that alarm will go off virtually instantly.

COMMISSIONER BRADFORD: So he's really inferring the size of the leak from the radiation alarm as much as he is from any knowledge of actual gallonage, then?

MR. McCRACKEN: That alarm tells him he has a leak. He would also be seeing concurrently, if he had a large leak, if you rupture a tube, get a 100 gallon leak, he'll take that up on loss of pressurizer.

COMMISSIONER BRADFORD: Right. No, but I was talking more about the kind of thing Darrell was talking about in the minimum end of the range, the .3 gpm.

MR. EISENHUT: You get an inventory balance, also.

MR. McCRACKEN: Yes, you simply go by an activity balance on the primary side, activity on the secondary side, and all your decay half-lives; you can calculate what it should be.

MR. EISENHUT: You said activity balance. You mean inventory balance on the primary.

MR. McCRACKEN: Radioactivity.

COMMISSIONER BRADFORD: Wait a minute. You aren't saying the same thing.

MR. EISENHUT: It's not a radioactivity balance. It's a mass balance, flow balance. The radioactivity trips you off and tells you you have a leak. It doesn't necessarily tell you how big the leak is.

COMMISSIONER BRADFORD: Yeah.

COMMISSIONER AHEARNE: Since the water is radioactive, you could do it either way.

MR. McCRACKEN: Usually what occurs, if it's a fairly large leak you'll pick up the water balance as Darrell is going through. On the very tiny leaks, smaller ones, usually the activity is a little accurate.

COMMISSIONER AHEARNE: Could you differentiate "tiny" and "large"?

(Laughter.)

COMMISSIONER AHEARNE: Somewhere in there, where's the --

MR. McCRACKEN: Let's say less than .3 gpm is tiny and greater than .3 gpm might be large. It's that kind of a ballpark.

COMMISSIONER AHEARNE: .3 gpm --

MR. DENTON: Over a day's period, total inventory over a day's period, how much water you put in the power system plus the known losses.

MR. EISENHUT: Because you see, it takes you longer as you get smaller. But at the same time, as you get smaller, your concern is generally less. So I mean, you make those two balance somehow.

But you know, if you start talking to the people, some people will say, well, the accuracy below .3 I really don't have any confidence in anyway. The .3 when we impose it as a requirement on some plants was right about the threshold of where people feel they really have confidence.

Anything below that they'll say, I have to take some additional measurements in time to know whether I really got it.

CHAIRMAN PALLADINO: Darrell, I notice you have some requests, I believe you have requests, for additional sleeving at other plants. What criteria, how do you decide whether to say yes or no.

MR. EISENHUT: With the technical staff.

MR. MURPHY: The Licensee -- the technical specifications do not provide for plugging as the approved repair procedure for defective tubes. Sleeving is not generally recognized in the technical specifications as an acceptable repair procedure. Therefore, to sleeve degraded steam generators they must obtain NRC approval to change the tech specs.

At San Onofre, they submitted, the utility submitted a comprehensive technical support package describing the design and development of their sleeving process, the qualification testing and analysis was performed. The sleeves had been designed in accordance with the ASME code.

MR. DENTON: I think the option is left with the utility to propose replacement plugging or sleeving. It's at his option, and if they propose sleeving then we do the review.

CHAIRMAN PALLADINO: But I was getting at what criteria do you use to decide yes or no, whether the sleeving is done or not.

MR. DENTON: Well, on the San Onofre sleeving we did use a unique approach there, the so-called independent design review. We required that the San Onofre utility convene a panel of people knowledgeable in all the aspects of this operation, the welding aspects, the metalurgical, corrosion, heat transfer, and a several day meeting was held in Pittsburgh in which we participated, and Westinghouse presented their rationale for the resleeving to the utility. The utility had a panel of experts and we observed and participated in that and examined all the questions that were raised.

And then about 30 days later the utility submitted its proposed package addressing the questions that it raised. We reviewed that one and approved it on that basis.

COMMISSIONER AHEARNE: Is it really the steam generator manufacturer who ends up making additional proposals?

MR. DENTON: I think the utilities depend on the vendor very heavily.

MR. EISENHUT: I think we don't really have a set of criteria.

CHAIRMAN PALLADINO: You're satisfied if the procedure looks straightforward.

MR. EISENHUT: You've got to look at whether it maintains integrity, the thermal hydraulics.

CHAIRMAN PALLADINO: Let's see. Another question in the back of my mind -- again with regard to sleeving -- oh, yes. Are you following, or how are you following the experience of Palisades and San Onofre, the other places where they've already done sleeving? I remember you said you had a general feeling it was working pretty well.

MR. EISENHUT: We have requirements. After they put those in, we generally put in a requirement that they go in and do an in-service inspection on the tubes in some short period of time. San Onofre I think was six months after they did the operation, and the others -- generally the others were smaller. They were a sample.

MR. DENTON: Yes, that's the real verification.

MR. EISENHUT: It's a sampling. The approval of sleeving incorporated an inspection program and reporting the results of that.

CHAIRMAN PALLADINO: What are you finding out? For example, Palisades you said was three years.

MR. EISENHUT: So far we haven't really found any degradation or any leaks reported on those sleeve tubes. But remember that there are only 32 tubes sleeved at

Palisades, so it's a small inventory.

COMMISSIONER AHEARNE: San Onofre is different.

MR. EISENHUT: San Onofre is the first time we went to -- we permitted --

COMMISSIONER AHEARNE: 7,000?

MR. EISENHUT: 7,000. It's basically all the tubes that really had a problem.

Ginna, Point Beach -- Point Beach is just now doing it right now on a sampling basis. The Board just authorized that. The only other plant was Ginna, that did 20 tubes. So there's really not been enough experience to see anything come back.

I don't take too much comfort in the fact that there hasn't been any degradation or leaks, because there just hasn't been that much.

Now, I should say, the industry is really following the sleeving, because that could be an answer to a lot of their problems, they believe.

MR. DENTON: You're limited in where you can resleeve to some extent. It's very difficult to get sleeves in the outer row of assemblies. So if they're the ones that are giving you problems, it's much more difficult.

CHAIRMAN PALLADINO: Can you resleeve the U-bend?

MR. DENTON: It's only maybe about a yard-long sleeves.

MR. EISENHUT: All the sleeves proposed now have been at the bottom. As Harold said, it's oh, two or three feet. It's been down near the support plate, right above the support plate -- above the tube sheet, I'm sorry.

COMMISSIONER AHEARNE: I noticed in your paper that you sent down it seemed that a lot of the problems, many of the problems, can be traced to condensers. Do we have anything that governs the performance of the condensers?

MR. EISENHUT: Not at this time. We don't have any requirement on condenser performance, nor do we have a requirement such as a tech spec on impurities in the secondary side. It's been something we've been discussing now for several years. One of the products that may come out of the unresolved safety issue A-3, which is in the final stages --

MR. DENTON: And we've never quite known how to -- if we knew what the material would be, we'd probably have been more active in proposing something. At one time it was felt that U.S. utilities were not as rigorous in keeping secondary water chemistry up to par as maybe other countries, because there were perceived differences in performance. I think today those differences in performance are going away to some extent.

COMMISSIONER AHEARNE: Well, let me ask on that

then. I noticed in looking down through this --

MR. DENTON: Go ahead with the question.

COMMISSIONER AHEARNE: The question is, looking at Japanese PWR's, Westinghouse designed, built, any similar type systems, no denting.

MR. EISENHUT: Denting was a phenomenon that -- it's fair to say, you're right, both the Japanese and the Europeans kept a much tighter control on the condenser. And we at one point even proposed a secondary coolant tech spec, and even issued it for trial use and for comment.

But it's very difficult to pin it down. It turns out the philosophy, the operating philosophy, is different in those countries.

COMMISSIONER AHEARNE: In what sense?

MR. EISENHUT: They do aim towards keeping a very tight condenser. The minute they see any problems that are coming in, they may shut down the plant.

Ringhals happened to have been the plant that was monitoring chlorides in the secondary system, because they thought that was potentially a bad actor. They were monitoring and they kept the plant -- I believe they kept all the chlorides below something on the order of 100 parts per billion, very small.

They're starting to see denting finding its way into the steam generators.

COMMISSIONER AHEARNE: But the Japanese have run many of their plants for a long time --

MR. EISENHUT: That's right.

COMMISSIONER AHEARNE: -- without denting.

MR. EISENHUT: The only belief we have is it's tied in the secondary chemistry control.

MR. DENTON: With the economic incentives, you would think that if there were a better way to run it it would be picked up.

COMMISSIONER AHEARNE: What I am having difficulty understanding -- and I don't mean -- it doesn't automatically seem to be an NRC problem at the moment, but here you have the same kind of generators, same kind of tube support, same kind of tubes. And on one side you have these problems, and the other side the problems -- and the problems don't turn out to be cheap to fix.

MR. DENTON: That's right.

COMMISSIONER AHEARNE: They turn out to be very, very expensive. I was just curious.

MR. EISENHUT: But again, it's a piece of the philosophy. For example, Mahama in Japan was one of the first plants to have severe wastage and they thought the problem was so bad they went and ordered spare steam generators, which they have at the site.

Two other European plants have ordered spare steam

generators and have them sitting at the site. They literally have railroad tracks in the plant to roll the old ones out and roll the new ones in.

So the emphasis there is --

COMMISSIONER BRADFORD: Where do the tracks go?

MR. EISENHUT: They go to a wall of the building, where there's a big hatch in the wall --

COMMISSIONER BRADFORD: No, I mean the other way.

MR. EISENHUT: They stop under the steam generator.

I think it's got to be tied to the secondary chemistry.

MR. DENTON: And each utility says that they've operated fossil plants for a long time, they understand the nature of their water and their chemistry, and that they know best how to protect their equipment.

MR. EISENHUT: It could be the U.S. just has bad water.

COMMISSIONER AHEARNE: I see. But at the moment you don't have any conclusions as to control of condenser, control of --

MR. EISENHUT: No, but it is one thing that is in our drafted-up solutions to where we're coming in on the U.S. side. It's very controversial, though, because it's more toward -- as Harold said, it's more of an economic

situation, unless you let it get to the point --

COMMISSIONER AHEARNE: Well, at some point when your problems are so frequent, it's more than an economic situation.

MR. EISENHUT: Yes, we certainly agree with that. We're saying, though, that the economic incentive should be there much greater than the safety incentive, because you hit it much sooner.

MR. DENTON: It's one of those areas where we are also faulted for moving into an area --

COMMISSIONER AHEARNE: Yes, I understand.

MR. EISENHUT: -- that's not so clear, and we've stayed out of it.

COMMISSIONER AHEARNE: Another question. I noticed in your paper you indicated that some plants have gone to, on the Westinghouse, the inner rows. They've blocked row one and now they're blocking row two.

MR. DENTON: Pieces of row two around the flow side, where, remember, that was due to an hour-glassing problem where the support plate squeezes on the upper row. Many of the plants that had severe hour-glassing plugged row one and the regions of row two right next to the flow sides, yes.

COMMISSIONER AHEARNE: And that's something that is of no concern?

MR. DENTON: Plugging those rows of tubes, that's right.

COMMISSIONER AHEARNE: Are there problems as the steam generators are put together? I notice two of your problems, one someone had dropped a hacksaw in, another there was metal expansion tape.

MR. EISENHUT: Well, I think it's a concern. I think it's sort of the general quality control. And you monitor for things like the tape when it was vibrating and wore through two or three tubes. You monitor for that degradation by your inspection process. And if in fact you develop a small leak, we have got confidence we'd pick it up.

And even if it's not picked up, they have a procedure for handling that kind of an event, that kind of an accident.

COMMISSIONER AHEARNE: Now, you have newer problems that have been showing up, and the three that I guess I noticed there were the pitting at Indian Point, the nonphosphate wastage at St. Lucie, and then this Ringhals problem. We end up having situations where there are problems, the causes aren't identified, but we end up putting on some kind of requirements, a change in tech spec for example.

Is the basis of that primarily increased

surveillance rather than modifications which is our best estimate as to the solution?

MR. EISENHUT: Yes. We really aren't trying to solve the problem. The only thing that we can do is put on more inspection requirements, more plugging requirements, and say, unless you can understand the phenomenon, unless you can explain what's going on, you must remove those tubes from service.

Now, one other thing I should point out, though, on the foreign experience, is the point I made earlier on that table, that there's a lot of missing information. A lot of foreign countries when we talk to them, they don't publicize all of the experience they have. And it's also, the table is clearly a couple of years out of date.

So it's not clear to me that the foreign countries are that much cleaner. It is true that historically they have had less degradation than in the U.S. How much we don't know.

COMMISSIONER AHEARNE: And your sense of that is perhaps tighter control over the water chemistry.

CHAIRMAN PALLADINO: Okay. Any other questions?

(No response.)

Well, I appreciate the presentation. I think we all do. I think it's an item we're going to want to have periodic briefings on and be kept abreast of any new

developments.

Okay, we'll stand adjourned.

(Whereupon, at 11:50 a.m., the meeting was adjourned.)

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NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before the

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in the matter of: BRIEFING ON PWR STEAM GENERATOR PROBLEMS

Date of Proceeding: 12-4-81

Docket Number:

Place of Proceeding: Washington, D. C.

were held as herein appears, and that this is the original transcript thereof for the file of the Commission.

Harold B. Alderson

Official Reporter (Typed)

Harold B Alderson

Official Reporter (Signature)