16-5A

INTERVIEW OF:

Mr. Kyle Jones
Extra Control Room Operator/Plant Vogtle
March 26, 1990, 7:13 p.m.

ACCURATE/AUGUSTA REPORTING, INC.
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ADDENDUM TO INTERVIEW OF Kyle Johns
(Print Identity of Interviewee)

Page	Line	Correction and Reason for Correction
6	20	Should read, Lube oil, in and outlet temperatures low.
9	16	Should read, It loaded on CCW, ACCW ACCW is another cooling system its ~~tot~~ not "A" tr CCW
18	14	Should read, Have to reset from "LOCA"
19	2+3	The Procedure number is 11885-C not 11886-C.
20	3	Change troop to droop

Page 1 Date 3-29-96 Signature Kyle A Johns

ADDENDUM TO INTERVIEW OF Kyle Johns
(Print Identity of Interviewee)

Page	Line	Correction and Reason for Correction
25	19	Answer should be NO we do not tag out these instruments for calibration

Throughout Doc
Change last name to Johns

Page 2 Date 3-29-90 Signature Kyle A Johns

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PROCEEDINGS

The following interview of Mr. Kyle Jones was held at Plant Vogtle, Administration Building, on Monday, March 26th, 1990 at 7:13 p.m.

Members present with the Incident Investigation Team, [IIT] were as follows: Mr. Alfred Chaffee, [team leader], Mr. Bill Jones, Mr. Harvey Wyckoff, Mr. Rick Kendal, Mr. Paul Dietz, Mr. Mike Jones, Mr. Warren Lyon, Mr. William Lazarus, Mr. Gene Trager, and Mr. Garmon West, Jr.

EXAMINATION

BY MR. CHAFFEE

Q. This is March 26th at 7:13 in the evening and this is the IIT team at Vogtle. And your name is?

A. Kyle Jones.

Q. And your position?

A. I was an extra control room operator that day.

Q. Okay. How long have you worked for Vogtle and what positions?

A. I came to Vogtle, January of 1984 as a plant equipment operator.

Q. Would you tell us what -- you know, what you observed and what happened during the event on Tuesday?

A. Okay. I had been taking the operator logs in the control room when the blackout occurred -- lost power. And the diesel generator started and then it tripped back off as loads started sequencing on. And before all of them got loaded on, it tripped off. At that time, we contacted the outside operator to have him go to the diesel and see what kind of alarms he had; see if he could find out anything about why the diesel tripped. And he got out there and reported back that he had one target relay, or not a relay but just a target trip, and that he saw no other reason for it to trip. At that time, the SS and OS decided that we would need to reset the sequencer to get the diesel started again. We'd let it load up. We let it start in auto with the loads being pulled lock and then we'd load them on ourselves. So I was talking to the operator at the diesel. We reset the sequencer, the diesel started up, breaker closed in; the output breaker on diesel, and then NSCW was loaded onto it. Right after NSCW was loaded on it, we loaded on the MCCs so the NSCW discharge valves would have power to them.

Q. Did you actually turn the switches? Were you loading them or did you observe that?

A. No, I was -- I was on the head or on the Gai-tronics with the man at the diesel.

Q. But what's the "Gai-tronics"?

A. That's the intercom system. Okay. That's how we established communications to start with with the diesel.

Again, the diesel tripped, and that time the operator out there reported that he got -- the first thing -- the first alarm he saw come in was the jacket water low pressure trip alarm, and it was followed by several other alarms, one of them being the jacket water high temp and I don't -- I don't know what the other ones were that came in at the time.

The OS, the SS, and the rest of the crew talked again and decided probably that the best thing to do would be to emergency start it and monitor the parameters. So we sent a SRO out to diesel, sent another SRO down to the sequencer to reset it again. This time we started the diesel. Okay, before we started the diesel, we put everything -- pulled a lock again, all the pumps; NSCW, CCW. The diesel was emergency started, came up. We had a few alarms come in, normally comes in with a start -- they reset. We had a sensor malfunction alarm that stayed in.

Q. You said when the diesel normally starts, you did get some alarms and then --

A. Yes.

Q. -- then they go away?

A. Yes. Yes, we always get some jacket water temperature alarms. They'll come in and then they'll -- they'll reset. And they did that; they came in and reset. We had that one -- we had the lube oil low level that stayed in and a sensor malfunction alarm that stayed in. So we went ahead and loaded the NSCW on and by that time, I was on the headsets with -- talking to John Acree at the diesel.

Q. Okay. Is it possible that one of the alarms you normally get in and then goes away is -- that's a low jacket water pressure?

A. No, it's not. That's a -- the alarm low jacket water pressure is a -- is a low jacket water pressure trip. So if you get that in it -- it'll trip.

Okay. We loaded the NSCW on for diesel cooling, waited the forty-five seconds and the valve stroked open and temper -- temperatures stabilized on the diesel, and this time it maintained -- it stayed running. And the PEOs -- we had three PEOs at the diesel end with Mr. Acree and they started right away taking the operator logs. We also had them -- them monitoring the oil pressures and all when we did start it.

After we saw that the diesel was going to run this time, then we loaded on the CCW and then got RHR back in service for cooling. Then it was -- then the main thing was, they wanted to get RAT "B" put back in service so we could put "B" train, "B" bus back in; and so we started working on that and got it returned to service after, I don't know how long, maybe about an hour and got "B" A03 put back in service.

EXAMINATION

BY MR. DIETZ

Q. What was your involvement with the bringing RAT "B" back to service?

A. I -- I didn't have any involvement. I was on the headset with the diesel and monitoring that and keeping status between the diesel and the control room. So some other operators worked on getting the RAT back in service.

Q. There was no difficulties or any kind of difficulties while any of this was taking place with the diesel?

A. With the diesel, we had that -- the sensor malfunction in. We got the ARP out on that and went through it, and we also had other personnel at the diesel by that time, maintenance and INC and all. And --

Q. What sensor malfunction are you talking about?

A. I can't even remember that name of it. It's on the air trip system.

Q. Is this something that can keep the diesel from starting or running or --

A. It -- what the ARP said was that when this sensor failed, there was another sensor that -- that if that sensor failed, if the other sequence -- if the other sensor failed then the diesel would trip. Okay. So he had you check control air pressure, and we checked that and it was fine, and then the alarm reset. And we also had the low lube oil level in and maintenance added oil to that; cleared that a lot.

EXAMINATION

BY MR. WYCKOFF

Q. I'm kind of fa‑‑inated by this business of getting a lot of alarms whenev r the diesel starts. Maybe that's a natural thing in that, but I'd sure like to know a little about it. So have you been down at the diesel room and you've seen this personally?

A. Yes. We see it in the control room too, also. We had the same thing.

Q. Okay. Would you tell us a little about it?
What are these alarms?

A. It'd be like a jacket water low temperature in, low temperature out. It's the -- it's the low temperature alarm.

Q. The water temperatures in and out?

A. Yes.

Q. What other kinds of --

A. Lube oil, in and outlet temperatures load.

Q. Lube oil, temperatures --

A. Uh-huh (yes).

MR. CHAFFEE: But those don't give you trips though?

A. No, they sure don't.

Q. But has anybody -- do you know or has anybody told you why all these alarms pop up?

A. Well, when you start diesel, your jacket water and lube oil keep warm system shuts down, and you engine driven systems pick up. So your flow rates change and your flow rates through your heat exchangers change and until the control valves can change to compensate for that, then that low temperature may come in.

Q. But these are non-tripping functions.

A. That's correct.

Q. These are alarming functions. Could it be that if this switchover and the function of these various regulating valves can affect just plain alarms, it can also affect trip sensors and what they do? I'm asking.

A. I don't -- I don't know.

Q. I'm trying to explain all of these trips that we're getting in my own mind, and you've introduced a phenomena here I hadn't heard about. In other words, at the time the diesel starts, we go from the standby systems to the machine driven systems --

A. That's correct.

Q. -- and a lot of things go on.

A. Yes.

Q. And these things are upsetting all things to do with oil temperature and oil flow and water temperature --

A. Yes.
Q. -- and water flow. And these trips that we see going out have to do with water pressure and oil pressure?
A. That's correct.
Q. So it all seems to -- like it might all tie together.
A. Well, these -- these low temperature alarms, they have -- they have always come in. I mean it's not -- it's not something that started last week. So, you know --
Q. Oh, no, I can understand that. But it could be it's just kind of worked out up until now --
A. Yeah.
Q. -- and something changed a little more. But there seems to be kind of a bowl of spaghetti, doesn't it, here. It's an interesting area at least.
A. Yeah.
Q. It sounds like this is a murky affair that goes on, not that I know the way out of it, mind you. But it could -- it could have some hope of explaining all these trips that we're --
A. Yeah. Oh, I don't -- I don't know. I mean --
Q. No, I don't know either. I just --
MR. KENDAL: Kyle, I have a question.

EXAMINATION

BY MR. KENDAL

Q. You indicated that you believe that the diesel generator tripped off the first time before all the loads had sequenced on.

What led you to believe that or what indications were there that you believe the sequence had had to complete?

MR. CHAFFEE: And what did you mean by "sequenced on"?

A. Okay. On the diesel; on the loss of power, the sequencer starts the diesel, it strips the buses and then it loads your needed loads back on.

MR. CHAFFEE: Does it load this NCSW?

WITNESS: NS -- NSCW, it loads on.

MR. CHAFFEE: It loads it on?

WITNESS: It load on CCW -- "A" CCW.

MR. CHAFFEE: So when you guys were saying that it tripped before, did it trip before CCW came on?

WITNESS: [No verbal response.]

MR. CHAFFEE: I see I'm getting ahead of the question.

Q. [By Mr. Kendal] My question is, are you sure that the loads had not completed sequencing, and if you're pretty sure that, you know, just a feeling or was there some kind of indication, or did you have to go on?

A. I guess it's really just, I guess a feeling.

Q. Just your impression from the way things went on?

A. Yeah, I didn't think it -- they had -- had time to load all those loads on. I didn't think it -- it had run that long. I know it loaded on NSCW because I did see that.

MR. KENDAL: Do you happen to know what the last load is that is on in this particular mode or whatever?

WITNESS: I don't know for sure; sure don't.

MR. WYCKOFF: Do you think it tripped out before the bypassed trip-offs were reset, such as oil pressure and water pressure, high temperature; high water temperature?

WITNESS: I'm not sure on that.

MR. WYCKOFF: You made one other statement that was kind of interesting and well could be. You said that on the first trip off of the diesel generator that you only saw one alarm and that was low water pressure. Are you kind of sure of that; you really saw it?

WITNESS: That was what the operators at the diesel told me. Because I -- at that time, I was at the -- over at the other side of the control room at the RO desk talking on the page when that came up. And that's what the operator at the diesel said, that was the first thing he saw come in, and he said that was followed by about five more alarms.

MR. WYCKOFF: I'd like to ask you one other thing. These alarms that come on that don't trip the diesel off but they do come on after you start the diesel, how soon is it that they come on; a few seconds or a couple minutes?

WITNESS: Yeah, just a few seconds. I'd say within -- all of them within ten seconds, they clear.

Q. [By Mr. Kendal] You indicated that prior to the second start and the second start is the one that after it tripped after the second start that people went down to the diesel room and figured out that it was low jacket water pressure, or I guess they saw it in the control room that it was low jacket water pressure, whatever, but before the second start, the one that you started by resetting the sequencer, you put loads and pull to lock prior to that start?

A. Yes, we did do that.

Q. Okay. So on the second start attempt and the emergency break glass start, loads were put and pull to lock?

A. Yes.

Q. So for the second start, the sequencer didn't have as much stuff to sequence?

A. It didn't sequence on. We had NSCW and CCW and pull to lock.

MR. CHAFFEE: Did it seem to you like the second time it started and operated that it ran longer than it did the first time?

WITNESS: Yes, it did to me. It seemed like it did.

MR. CHAFFEE: Does it make any sense to you that that might be related to the fact that you perhaps had some of the loads pull to lock so the sequencer didn't have to bring them on?

WITNESS: I don't know. I don't think it -- I don't think it had any effect on it.

MR. WYCKOFF: Are you able to tell us much about how it's designed relative to air pressure? We've talked to a number of people and we'll probably run into somebody that knows, but let me ask you what you understand. And I don't know. This is not -- we've heard that it's supposed to be able to make about five starts. We're confused as to how many it makes before it locks out and wants some manual help, so it's saving air so that you can have a manual try. Do you know what pressure it is that it stops trying to start automatically?

WITNESS: A hundred and fifty pounds.

MR. CHAFFEE: And how does it -- when it

gets the pressure gets down to 150 pounds, at that point it will not start or at that point --

WITNESS: It will not auto start. It will not -- it will stop trying to auto start.

MR. CHAFFEE: Does it interlock or something or it just --

WITNESS: Yes, it's interlocked.

MR. KENDAL: Is that in both the emergency and normal starts or just the normal?

WITNESS: Yes, both.

MR. KENDAL: It's in both of them?

WITNESS: Uh-huh (yes). That gives -- that gives the operator a chance to determine -- see if he can determine why it's not starting and see if he can correct it and still have enough air left to start it.

REEXAMINATION

BY MR. CHAFFEE

Q. So when it gets to 150 pounds, whether that's enough air or not to start it, the thing has an interlock that prevents it from auto starting unless the operator takes some manual action to override that interlock?

A. That's correct.

Q. Can you override that interlock locally at the --

A. That's all you have to do, is take the diesel generator local control. You take it local control out there, then you can start it with less than 150 pounds pressure in the tanks.

MR. LYON: Can you local control or do you have to go break glass start?

WITNESS: You can -- I'm -- you can do either start. You can just do a local manual with less than 150 pounds.

MR. LYON: Either way?

WITNESS: Either way.

Q. [By Mr. Chaffee] At anytime during all this starting during all this starting and tripping of the diesel did the pressure get down to 150 pounds?

A. No, it didn't.

Q. Do you know how low it went?

A. After the first start and before the second start, it was 210 pounds and I don't know what it was when we did the emergency start.

Q. Do you know what it was before you had the first start?

A. It'd be -- around 245 is what it usually is.

Q. So it went from 245 down to 210 after the first start?

A. Uh-huh (yes).

Q. Is that typical or do you know what the typ- --

A. That's typical, yes.

MR. WYCKOFF: Of your knowledge then, the air pressure never behaved irregularly. It wasn't overly low at any point?

WITNESS: No.

MR. LYON: Let me make sure I understand. We started around 240 or so. After the first try you were at --

WITNESS: 210.

MR. LYON: 210.

WITNESS: Uh-huh (yes), with the air compressors running, pumping it back up.

MR. CHAFFEE: When do they kick in?

WITNESS: They kick in at 225, I believe.

MR. MIKE JONES: So they're on non-vital power; the air compressor?

WITNESS: Yes.

MR. LYON: We know those were running.

WITNESS: Yes.

MR. LYON: Because that -- that's new information for me. I had never heard that the air compressors were running.

WITNESS: Let me -- let me say I'm not sure on that because I --

MR. LYON: Okay.

MR. CHAFFEE: How would you have known that?

WITNESS: I can't remember if I ask if they were running or not.

MR. CHAFFEE: But you had not indication in the control room?

WITNESS: But the -- no. The operators at the diesel would know.

MR. LYON: Okay. Now, after the second start, you didn't have any information as to what the air pressure was --

WITNESS: No.

MR. LYON: -- after that second start?

WITNESS: That's correct.

MR. LYON: Okay.

MR. WYCKOFF: At what pressure does it lock out so it won't try to start at all?

WITNESS: I don't know of any pressure that it won't try to start. They say that it won't start below about ninety pounds, just due to -- it won't roll it over fast enough.

MR. CHAFFEE: Why did they go to emergency start the third time?

WITNESS: Emergency start bypasses all but four trips on the diesel.

MR. DIETZ: And what are the four trips that remain?

WITNESS: Low lube oil pressure, high jacket water temperature, over speed, and generator differential.

MR. CHAFFEE: Could you say those again?

WITNESS: Okay. Low lube oil pressure, high jacket water pressure, I mean, excuse me, high jacket water temperature, over speed, and generator differential.

REEXAMINATION

BY MR. WYCKOFF

Q. I noticed up on the board there, there were over current relays. Will they trip the machine off? Many plants don't go out on over current because of the need to pull safety loads.

A. Yeah.

Q. And you didn't mention this here and I can't imagine them being in the circuit that puts things in and out. So I ask you the question, what about those over current relays that are up there on the top, are they in service this entire time?

A. No, they aren't. That's -- that's the only four trips that'll trip the diesel on the emergency start.

Q. Are they in service after this period?

A. You mean on a normal start?
Q. Well, after it's running for -- for the sixty seconds or whatever it is.
A. On emergency start, they -- it locks out all the other trip signals --
Q. Including the over current?
A. -- for the entire run. For the entire run.
Q. Including the over current?
A. Yes. To my knowledge, the four is all that will trip it.
MR. DIETZ: So that before the entire run, you have to shut down the diesel to put the other trips back in?
WITNESS: Have to reset from local, shut down the diesel, and put the trips back in.
MR. KENDAL: So to put the trips back in does require a diesel shut down? You can't just reset a button while the diesel's running?
WITNESS: No, you can't reset those tripped.
MR. KENDAL: You indicated that there were three PEOs down there that were monitoring diesel parameters and taking operator logs.
WITNESS: Yeah.
MR. KENDAL: What does taking the logs

consist of?

WITNESS: There's a procedure 11886 -- 11886-C that -- it gets your lube oil pressures, turbo pressures, cylinder temps, air pressures and it just looks at -- at most everything on the diesel.

MR. KENDAL: Is that a procedure for anytime the diesel starts regardless of --

WITNESS: Yes. We take them when we run surveillance tests. I think surveillance tests directs you to start them thirty minutes after it started. The normal system operating procedure directs you to start taking them ten minutes after it's running. And what we did on this day was started just as soon as we had the diesel up and we took them every thirty minutes.

MR. WYCKOFF: Do you have independent keep warm on both the water and the oil; each has its own?

WITNESS: Yes.

MR. WYCKOFF: They're at 170, 180, 190?

WITNESS: I believe lube oil is at 170. Yeah, it's at 170. And they have a circulating pump and a heater on both systems.

MR. CHAFFEE. You're very knowledgeable in these diesels. Have you recently had training in these or have you previously --

WITNESS: When we brought diesel 1-A

back up after this rebuild, I ran it that day. That's one thing -- we did the over speed test and setting up the speed troop all that. I was the operator on it.

MR. CHAFFEE: Oh, so you were actually out there at the diesel? Is that -- or in the control room?

WITNESS: This is -- okay. This outage -- we tore diesel 1-A apart, right?

MR. CHAFFEE: Right.

WITNESS: They rebuilt it. When we brought it back out of the outage, and bring it up to do the engineering test on it, I was the operator at the diesel, running it.

MR. CHAFFEE: Oh, so, how -- I mean a number of shifts or a shift?

WITNESS: A shift. We started about -- I think we had about six starts that day.

MR. CHAFFEE: Oh, so you actually observed a start six times?

WITNESS: Yes.

MR. CHAFFEE: Okay. Now, how long ago was this?

WITNESS: This was -- I can't remember the date, but it seemed like about a week before.

MR. CHAFFEE: Before the Tuesday thing?

WITNESS: Yeah.

MR. CHAFFEE: Did any problems occur during those starts?

WITNESS: When we first started the diesel up, we had three indicators that didn't indicate on the boards, so we shut it down. That was jacket water pressure, lube oil pressure, and turbo charger pressure, left bank. And we found the reason for that was the meters being isolated. Those meters -- in the back of the panel, there's isolation valves and they -- they were isolated. And -- but as far as the diesel running and starting and all, we had no problem with it. It --

MR. CHAFFEE: When you started it six times, did those -- the first time --

WITNESS: It's around that many.

MR. CHAFFEE: Okay. Let's say the first time you started it, how was it started?

WITNESS: It was a manual local start out at the diesel.

MR. CHAFFEE: Okay. Now, is a manual local start, does that have all the trips in or does it have some --

WITNESS: Yes, it has all the trips in. Also, another thing I can tell you about that start: the first two starts were what the vendor called a "slow start." They actually -- there's a load limiter on the governor and they dialed it back, and I'd start the diesel and then he'd bring it up to rated speed with that. So we did have problems on that with the keep warm system and all, but they had already told us that we'd have that because on a slow start, the keep warm system is cut off by -- the diesel sends a signal to him to tell him it's started, okay, and it goes by RPMs so with the slow start, the system kicked off but then it came back on, and you'd have to get that off. That was on the first two starts.

MR. CHAFFEE: Oh, I see. It would kick off because he had the diesels turning. I don't need to do it anymore. But, oh, it's starting so slow it's going down, then it would kick on again?

WITNESS: Yeah, right. That's correct.

MR. CHAFFEE: Oh, I see.

WITNESS: Okay. The vendor, you know, like I say he -- he had told us we was going to have problems with that. And how -- he told us we had to -- to press the start button again and it'd cut -- it'd cut all that keep warm system off.

MR. CHAFFEE: Okay. How many -- and then -- okay, so you did that start. You did the first two like that?

WITNESS: Yeah.

MR. CHAFFEE: But no problems with the first two. You did a local manual. Do you happen to know, is the local manual method of starting the diesel different in how it gets started when they have an under voltage condition? I mean is it very different or do you know the circuitry that well?

WITNESS: As far as I know, it's not -- it's not that -- it's not different.

MR. CHAFFEE: Okay. Well, after you did the slow starts, you then did a number of other starts that were normal. Was that done locally, manual?

WITNESS: Yes.

MR. CHAFFEE: And those also were --

WITNESS: Those also worked well.

MR. CHAFFEE: Were those done in close proximity of the first two? I mean you did the first two and then within a few minutes you did the next one?

WITNESS: Yes. Uh-huh (yes).

MR. CHAFFEE: Were they all -- they were all basically done on one shift, weren't they?

WITNESS: Yes, a twelve-hour shift.

MR. CHAFFEE: Once you started up, how long did you let it run each time?

WITNESS: The first couple of times it was only a few minutes, say less than five minutes. Okay.

Then, it seems like next run -- I can't remember how long. It seems like it was about a half hour. And then we had -- I don't know. There were different lengths because they had different, you know, different kind of tests that they had set up to do.

MR. CHAFFEE: Did they do a four-hour or an eight-hour run after that?

WITNESS: Yeah, we started it up. At that time, I started it -- that from the control run. Started the eight-hour run from the control room.

MR. CHAFFEE: Okay. Did that happen -- did they start that during the same shift you were talk- --

WITNESS: Yeah. I started it and turned it over to the next shift.

MR. CHAFFEE: And to the best of your knowledge, it completed that with no problems?

WITNESS: No problems that I -- that I heard of and it had no problem starting from the control room.

MR. WYCKOFF: Maybe I'll make this my last question. It's getting late. But maybe you could give us some sort of a feel, I want it at least, the extent of this overhaul. For example, did you jack up any cylinders and take out connecting rods and look at connecting rod bearings or --

WITNESS: I don't -- I sure don't know. I didn't get out to the diesel while it was torn apart.

MR. WYCKOFF: I mean jack up pistons. So you don't know if they removed heads or --

WITNESS: I sure don't.

MR. WYCKOFF: Okay, let's drop it.

MR. LYON: Is there a "tag it" procedure to isolate meters and things of that nature?

WITNESS: This -- these valves that we found closed were --

MR. LYON: Yes.

WITNESS: -- they should be covered in I&C Procedures for -- for recaling those instruments and all. Our line-up --

MR. LYON: Would you tag those kinds of things ordinarily and then remove the tags when --

WITNESS: Uh-huh (yes).

MR. LYON: So that is covered by procedure. Should the procedures have gotten those open again?

WITNESS: I would -- I would think they should have, but like I say, it's -- it's another department's procedure and I haven't ever had any dealings with them. Our line-up procedure doesn't cover those valves.

MR. LYON: So when you receive the diesel after the rebuild, as far as you're concerned, you expect it's ready to go?

WITNESS: All except for our line-up. We have a line-up --

MR. LYON: I understand.

WITNESS: -- but it doesn't cover that.

MR. LYON: Okay. Did you mention a 160 relay --

WITNESS: Yeah. There's a 160 -- it was a target on the diesel panel out there, on the generator panel. Slim Whitman told me that that was in when he got out there after the first trip.

MR. DIETZ: Do you have any idea what that is for?

WITNESS: I don't have any idea.

MR. KENDAL: Could be a voltage valve.

MR. LYON: Do you know if that was in at any other time?

WITNESS: It wasn't. I was never told that it came back in.

MR. LYON: Okay. So you know that it was -- you were told it came in the first time --

WITNESS: Yes.

MR. LYON: And you weren't told anything beyond that?

WITNESS: That's correct.

MR. LYON: Okay.

MR. CHAFFEE: So while you were in the control room, you were actually on the phones with the people in the diesel that --

WITNESS: That's correct.

MR. CHAFFEE: Is that -- did you become the controlman; that became your function, or were you in there --

WITNESS: I was already in the control room. I was, like I say, during the outage I was trying to do their logs so they could operate other equipment.

MR. CHAFFEE: So when the event occurred, you were sitting there doing the logs and then it occurred, and then -- and then how did you then come to man the phones?

WITNESS: Well, I just -- we needed somebody at the diesel, so I got the phone up and called the outside operator and directed him to go on out there.

MR. CHAFFEE: So once you got on the phones, did that put you in proximity of all the diesel indications?

WITNESS: Actually, I was on the -- on the other side of the control room to start with.

MR. CHAFFEE: The other side.

WITNESS: Up at -- by the RO desk.

MR. CHAFFEE: So then when you manned the phones, is that where you stayed or did you come over to where the -- over by the tower and --

WITNESS: I stayed there until they got a set of headsets at the diesel and then we hooked up and I went over to the diesel tower.

MR. CHAFFEE: Oh, I see. So at least initially --

WITNESS: It was after the second start that we got the headset --

MR. CHAFFEE: Oh, okay. So for the first start, you were over by the RO's panel, when that one came in.

WITNESS: Right.

MR. CHAFFEE: And then for the second start, you had headsets on and you were over by -- close proximity to --

WITNESS: The third start. The emergency start, I was over by the panel.

MR. CHAFFEE: And for the second start, where were you?

WITNESS: I was over at the RO's desk and there was two other -- two other people over at the diesel panel, but I don't remember who it was.

MR. CHAFFEE: Okay. So you were taking logs, the event occurs. Somehow it seems obvious they need somebody in contact with the diesel so you pick up the phone there at the RO's desk and get in contact with them and that's where you are for the second start.

WITNESS: Yes.

MR. CHAFFEE: And then you get headphones put on so then you go over by the diesel panel itself and then you're on the headphones for the third start that works?

WITNESS: Yes.

MR. LYON: Were you considered to be part of the operating team at this time or were you just an extra hand helping them out?

WITNESS: I was an extra hand.

MR. LYON: I mean prior to the --

WITNESS: Prior to it, I was the extra.

MR. LYON: When you took over some of this function, did you just simply recognize it was needed to be done? Did anybody ask you to do it or did you announce that you were taking this over as you did it? I'm a little confused on the process.

WITNESS: Really, I just -- I mean I knew it had to be done and so I took -- we were talking in the control room so everybody knew what I was doing. I knew what they were doing. But I just, you know, did take it because I knew it had to be done.

MR. CHAFFEE: Were you able to see on either the first or second trip from where you were at the RO panel, what alarms came in on the annunciators that looked like they indicated what the trip was --

WITNESS: No, I didn't see what it was.

MR. CHAFFEE: For either the first or second?

WITNESS: No.

MR. CHAFFEE: Did you overhear any conversations regarding that?

WITNESS: No, I didn't.

MR. TRAGER: About the incident, you indicated you were waiting for them to get headsets?

WITNESS: It took them a few minutes to get them.

MR. TRAGER: Did they have to find them or go someplace to get them?

WITNESS: I don't know. I did ask them if they had headsets and they said -- they told me they didn't have some; they were going to get some. So they did have to go somewhere to get some.

MR. TRAGER: So there were some in the next building or at the next diesel generator?

WITNESS: Yeah, I think they went over -- I think they went next door to the other diesel and got some.

MR. CHAFFEE: Why did they have to get headsets?

WITNESS: The headsets are a lot better to communicate on than the Gai-tronics. Any -- anybody -- I mean Gai-tronics are all over the plant. Anybody can pick up on there and talk anytime on the headsets, you know. It's --

MR. CHAFFEE: Was the Gai-tronics working?

WITNESS: Yeah, working fine.

MR. CHAFFEE: Is it different than the telephones?

WITNESS: Yes.

MR. CHAFFEE: Oh, okay.

MR. LYON: Would you comment on being able to hear over the Gai-tronics versus the headsets?

WITNESS: It's just as good as far as hearing quality. It's just that you have more interruptions on the Gai-tronic.

MR. LYON: With the diesel running and background noise and so forth, would that bother a guy down in the diesel room?

WITNESS: It -- I'm sure it would. We didn't have any -- we didn't have any problem.

MR. LYON: I hear that you wouldn't have any problem up in the control room. Your guy down at the diesel, I'm wondering if he can hear as equally well on the Gai-tronics.

WITNESS: I doubt he could.

MR. LYON: So he needs that system. Is that --

WITNESS: The headset?

MR. LYON: Yeah.

WITNESS: I think it's a lot better system than --

MR. LYON: To your knowledge, is there a place in the diesel generator room where a headset is supposed to be stored so that someone can walk in and grab it?

WITNESS: Okay. Behind the generator panel, there's a red box with two plugs, and that's the shutdown box.

MR. LYON: Yes.

WITNESS: And that's the one we used that day and there should be a headset and a cord hanging beside it.

MR. LYON: Is there any control over that, do you know?

WITNESS: I believe we have a surveillance procedure that we do to verify they are in place.

MR. CHAFFEE: Did you overhear any other conversations in the control room like -- or did you observe like heat up rate in the core when you were over by the RO?

WITNESS: Yeah, I kept hearing people. They were keeping track of it.

MR. CHAFFEE: Did you hear how high it got to?

WITNESS: The last I heard, it was like -- I believe it was 126, was what the highest on the thermocouples were showing.

MR. CHAFFEE: Did you hear any dialogue from the individual inside containment who was manning the Tygon tubes, any conversation? I guess there was speaker box or something in the RO's?

WITNESS: I didn't hear him -- sure didn't. I believe there was a speaker box.

MR. CHAFFEE: Did you overhear any

conversations regarding problems they had in putting out notifications?

WITNESS: No.

MR. WEST: Is there a one-to-one match between the annunciators you get in the diesel room versus those you get in the control room?

WITNESS: Yes, it's the same board.

MR. WEST: So Delta --

WITNESS I'm pretty sure that it is the same board out there.

MR. CHAFFEE: Have we asked the question about first out?

MR. WEST: No.

MR. CHAFFEE: Is there a first out on the diesel?

WITNESS: Yeah. There's a -- I learned this afterward, but the engineer says there is a first out on the diesel board.

MR. CHAFFEE: Is this locally at the panel or --

WITNESS: Yes.

MR. WEST: Do you know how it works?

WITNESS: No, I don't. Let me rephrase that. I know how it's supposed to work, but like I say, I just learned that it was there. It's -- it's supposed to have a different flash than -- than like the one on the RO panel. You acknowledge it; it shouldn't reset and should have a different flash on it.

MR. CHAFFEE: Do you know if any of the people that were at the diesel, you know, when this happened, did they have that knowledge were they therefore able to get any information?

WITNESS: I'm not sure. I'm not sure on that.

MR. CHAFFEE: Okay. Do you know if any of those annunciators are tracked or printed out in any of the computer type stuff that tracks annunciations and stuff; time when they --

WITNESS: It possibly could be on the alarm printer --

MR. CHAFFEE: Okay.

WITNESS: -- or the line printer.

MR. WEST: You were communicating back and forth with the operators in the diesel room?

WITNESS: That's correct.

MR. WEST: Did they mention first out --

WITNESS: No, they didn't.

MR. WEST: -- on any of the trips?

WITNESS: No.

MR. TRAGER: About the headsets, did that pose -- I got the impression that it made for some kind of delay. Was that the case?

WITNESS: No, it didn't cause any delay because we had them on the Gai-tronics.

MR. TRAGER: But if the diesel was operating in the unit?

WITNESS: Might've -- it probably would've been harder to hear.

MR. TRAGER: Did just one operator go for a couple of minutes to get the headset or --

WITNESS: I can't answer that. I don't know. I -- while he went to get the headset though, I maintained communications with somebody at diesel, so it didn't interrupt communication.

MR. TRAGER: Did they indicate there was no light in the generator room?

WITNESS: No.

MR. WEST: Did they reveal any problems at all that they were having at any time?

WITNESS: The only problems that -- were the annunciators that came and stayed, the sensor malfunction, and the lube oil, was the only problem I knew of.

MR. KENDAL: But no problems in terms of carrying out tasks or having difficulty with one of the tasks?

WITNESS: I didn't hear anything about that.

MR. KENDAL: I'd like to go back to this flash -- about the flash being different. Is the flash for the first out on the local panel different than the flash for the other alarms at the local panel?

WITNESS: That's what I've been told, but I haven't witnessed it.

MR. KENDAL: And do you know how that works in terms of if an alarm comes in and flashes at a different rate than other alarms that are flashing and maybe some conditions go away and it's reset; they may all clear, or --

WITNESS: I sure don't. I don't know.

MR. WEST: Do you get training on annunciators by way of your training?

WITNESS: Yes.

MR. WEST: Could you give us some sense of what that deals with?

WITNESS: Well, we get trained on -- we've had training on -- like the first out panel in the control room, trained on that, how to identify the first out annunciator there on the RO panel. I've also had training on the power supplies and automatic swap over features of the annunciator system in the control room, and had training on the response to annunciators by the alarm response procedures.

MR. TRAGER: Could I rephrase the question and ask you more about the light? I didn't mean no light, I meant no normal light. It's my understanding that there was only emergency lighting.

WITNESS: Like I say, they didn't -- they didn't say anything to me about it, so I don't know.

MR. CHAFFEE: Wait a second, I have a question. Doesn't normal lighting come off of the normal non-vital buses? I guess maybe -- okay, rhetorical question.

MR. TRAGER: It was my understanding that the[illegible] was no lighting except the vital engines and the emergency lighting that they have.

WITNESS: Uh-huh (yes). But like I say, they -- they didn't tell me anything about it, so I don't know for sure.

MR. WEST: Does an operator's training typically extend to local control stations or is it more focused in the control room?

WITNESS: As far as -- as what?

MR. WEST: I was thinking I guess specifically of annunciators. I was trying to get a sense of

--

WITNESS: It's more -- more in response to the control room.

MR. WEST: All right.

MR. CHAFFEE: Did you have any problems in the control with any loss of any types of indications when you lost the vital buses or just any types of indications in the control? Did you hear anything relevant to that?

WITNESS: No, I didn't -- I didn't hear any -- anything. We didn't lose any indications on the diesel that I know of.

MR. CHAFFEE: Don't a lot of the indications in the control room come from vital buses?

WITNESS: A lot of indications come off of vital buses.

MR. MIKE JONES: BOP.

MR. TRAGER: If you were powered, you'd probably see that, but shutdown, you probably don't have that.

WITNESS: And being the extra operator -- if I'd been the RO I'd probably observed a lot of them, or the BOP. But about the only thing I looked at when -- when it happened was I did -- you know, looked at the NSCW stuff to make sure it was coming up. That's -- that's all -- any cooling you've got to the diesel. You've got to get it back on.

MR. CHAFFEE: Oh, and the nuclear coolant service water?

WITNESS: Right, that was the thing I was looking at.

MR. CHAFFEE: That's what -- okay. I understand. Because if that doesn't come on, then the diesel's going to trip in over temperature.

WITNESS: That's right.

MR. CHAFFEE: How long do you have for that to come out before it could get you in trouble?

WITNESS: What our procedure says is that the diesel can run fully loaded for three minutes without any NSCW. We were carrying probably -- I believe we were carrying 2,400 kilowatts and a full load is 7,000.

MR. WEST: Was another operator communicating with the sequencer's role?

WITNESS: Yes.

MR. WEST: Do you know who that was?

WITNESS: No, I don't.

MR. CHAFFEE: Any other questions? Okay. Well, thank you very much. You've been very helpful.

[INTERVIEW CONCLUDED AT 8:04 P.M.]

CERTIFICATE OF COURT REPORTER

GEORGIA

RICHMOND COUNTY

I hereby certify that the foregoing interview was reported, as stated in the caption, by the method of Stenomask With Backup, and the questions and the answers thereto were reduced to typewriting by me or under my direction; that the foregoing pages numbered 1 through 40 represent a true, correct, and complete transcript of the evidence given on March 26, 1990, by the witness, Kyle Jones, that I am not a relative, employee, attorney, or counsel of any of the parties; am not a relative or employee of attorney or counsel for any of said parties; nor am I financially interested in the action.

This the 27th day of March 1990.

Margie Fox

MARGIE FOX, CCR B-1176

CERTIFIED COURT REPORTER

INTERVIEW OF:

MR. KYLE JONES
Reactor/Operator Plant Vogtle
March 26, 1990 at 7:13 p.m.

ERRATA SHEET TO THE DEPOSITION OF
KYLE JONES TAKEN ON MARCH 26, 1990

I do hereby certify that I have read the within and foregoing pages numbered 1 through 40, and that:

________ 1) There are no changes noted,

________ 2) The following changes are noted:

Page_____ Line______: ______________________________

Reason: ______________________________

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If supplemental or additional pages are necessary, please furnish same annexed to this Errata.

This _____ day of _____________________ 1990.

____

KYLE JONES

WITNESS:

____

05-17-90

PC

12:40 p.m. 3/28/90

I ordered Jimmy Cash to quarantine the following:

Trip disk pack for Unit 1 ERF that was collected during, immediately prior to, and immediately following the event.

Jimmy will check if any proteus data exist. His understanding is that the data have been overwritten. If these data exist, they are also quarantined.

Warren Lyon

1:32 PM Jimmy called to inform me that there are no proteus data.

12:40 PM 3/28/90 I ordered Jimmy Cash to ~~quarten~~ quarantine the following:

Trip disk pack for Unit 1 ERF that was collected during, immediately prior to, and immediately following the event.

~~Proteus~~

Jimmy will check if any proteus data exist. His understanding is that the data have been overwritten. If these data exist, they are also quarantined.

[illegible signature]

Skip

Al Chaffee

Southern Company Services Inc
Post Office Box 2625
Birmingham, Alabama 35202
Telephone 205 877 7936

CSM
JGA
RLM

05-18-90

W. C. Ramsey, Jr.
Project Engineering Manager - Vogtle

Southern Company Services
the southern electric system

February 16, 1990

Copy to PMK
Copy to JGA
[redacted]
Original to File

Vogtle Electric Generating Plant - Units 1 and 2
Final Response to Request for Engineering Assistance
No. VG-9011
File: X7BD111 Log: SG-8817 Security Code: NC

Mr. C. C. Miller
Manager of Engineering
Vogtle Project - Nuclear Operations
Georgia Power Company
Post Office Box 1295
Birmingham, Alabama 35201

Dear Mr. Miller:

The attached report is the Phase II response to REA VG-9011 which addresses the specific NRC concerns identified in Generic Letter Number 88-17 and subsequent responses. Also, this report verifies plant specific findings for WCAP 11916 that apply to Plant Vogtle Units 1 and 2. The results from the RCS venting analysis were discussed with a WOG contact at Westinghouse for concurrence prior to the issuance of this report.

This document completes activities concerning REA VG-9011. If you have any questions, please call David Dotson at extension 6850.

Very truly yours,

W. C. Ramsey, Jr.

W. C. Ramsey, Jr.

WCRJr/DRD/sm
Attachment
xc: G. Bockhold, Jr. (w/att.)
A. E. Cardona (w/att.)
M. W. Horton (w/att.)
C. R. Myer
R. E. Patrick (w/att.)
S. Pietrzyk (w/att.)
P. D. Rushton
NORMS
Document File (w/att.)
Project File

LOSS OF DECAY HEAT REMOVAL

ANALYTICAL STUDIES

for

VOGTLE ELECTRIC GENERATING PLANT

UNITS ONE AND TWO

A RESPONSE TO GENERIC LETTER 88-17

for

GEORGIA POWER COMPANY

SONOPCO PROJECT-VOGTLE

Prepared by

SOUTHERN COMPANY SERVICES, INC.

NUCLEAR PLANT SUPPORT-VOGTLE

EXECUTIVE SUMMARY

This report is the result of a Southern Company Services study conducted for the Vogtle Electric Generating Plant, REA VG-9011, regarding issues and concerns in NRC Generic Letter (GL) 88-17. This letter discusses the loss of the residual heat removal system during periods of reduced inventory in the reactor coolant system. This report partially fulfills the request made in NRC GL 88-17.

Westinghouse WCAP-11916 is a study of generic two, three, and four loop plants operating at a reduced inventory or "mid-loop" condition. The thermal hydraulic analyses performed in the Westinghouse study predict RCS behavior following the loss of RHRS cooling during mid-loop operations. Concerns addressed by the analyses include time to core boiling, the RCS pressurization rate, time to core uncovery, openings in the RCS boundary that can impact RCS recovery responses, and recovery operations for various RCS configurations.

This plant-specific study, VG-9011, verifies that assumptions used and conclusions drawn in WCAP-11916 encompass Plant Vogtle. Calculations were performed on the major operational considerations listed in the WCAP. No alternate recovery operations are suggested to replace those described in the WCAP. Suggested methods for improvements were made for operations not encompassed by the WCAP results. Plant Vogtle was modeled using the decay heat for 48 hours after shutdown and uprated fuel of 3565 MWt. A gravity flow calculation was performed which modeled RCS inventory addition from the refueling water storage tank (RWST) through paths other than those described in the WCAP.

In general, the results are as follows:

- The assumptions listed in the WCAP which maximize the core heatup rate and pressurization and minimize the time to boiling and core uncovery encompass Plant Vogtle.

- The estimated time to boiling of 8.3 min, time to core uncovery of 57 min, and RCS heatup rate of 8.6 F/min are conservatively close to the results predicted in the WCAP for a four-loop plant. The information in the operation procedures taken from the WCAP encompass Plant Vogtle's operation.

- The WCAP analysis implies that any vent with an area of 0.5 ft^2 or larger is adequate to prevent RCS pressurization. This finding does not encompass Plant Vogtle. If a RCS cold leg opening is present the [illegible] pressurizer manway or the three safety relief valves [illegible] vent path could result in an upper plenum pressure great enough [illegible] inventory out the cold leg opening. It is suggested that this RCS configuration be avoided.

- Gravity flow from the RWST to the RCS can be accomplished up to an RCS pressure of 35 psig. The gravity flow paths chosen and their respective flowrates are shown in Figures 2.2 and 2.3.

- The calculated time for working inside containment without a respirator is 27 min after inventory boiling begins. The calculated time for working inside containment until the temperature reaches 160 °F is 21 min with no containment coolers operating. With an open containment, a minimum of three coolers must be operated to ensure that temperature remains below 160°F for 57 min after loss of RHR; this would be necessary to allow personnel to continue containment closure activities prior to core uncovery.

- A review of the NRC questions to Georgia Power Company relating to GL Number 88-17 is in Section 4. This review relates the plant specific findings of this report to questions posed by the NRC.

- A review of GPC procedures was done to insure generic information from WCAP 11916 used in the procedures encompassed Plant Vogtle. Information concerning the use o[redacted].

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INTRODUCTION

Section 1 of this report reviewed and performed plant specific analysis in response to Generic Letter (GL) 88-17 programmed enhancements. Reviews were performed on GL 88-17 and Georgia Power Company (GPC) procedures to determine what information in WCAP-11916 required verification. A technical review was performed on WCAP-11916. A comparison was made of the decay heat rate and power levels between Plant Vogtle and the WCAP modeled plant. Information was obtained about the MAPP computer system, which can model various plant conditions, including mid-loop operations. Several calculations were performed to verify that results of the WCAP study encompassed Plant Vogtle. The calculations were time required to saturation, time required to expose the core, and Reactor Coolant System (RCS) heatup rate.

The analyses conducted in this section were based on NRC recommendations made to GPC in the initial GL 88-17. Section 3.4 of the letter directs: Conduct analyses to supplement existing information and develop a basis for procedures, instrumentation installation and response, and equipment/Nuclear Steam Supply System (NSSS) interactions and response. The analyses should encompass thermodynamic and physical states to which the hardware can be subjected and should provide sufficient depth that the basis is developed. Emphasis should be placed upon obtaining a complete understanding of NSSS behavior under nonpower operation. In its discussion, the NRC states that the Westinghouse Owners Group (WOG) has made an excellent start toward meeting this recommendation. Further mention is made of the different thermal/hydraulic analyses performed by (WOG) in WCAP-11916 for generic two, three, and four loop plants. The analyses and calculations performed in VG-9011 supplement the WCAP information for Plant Vogtle.

Section 2 of this report analyzed how nonpower condition phenomena impact plant operations. The background for the reviews was based on recommendations made in GL 88-17 and in the 60-day response letter. As in Section 1, several plant specific calculations were performed to verify that data in the WCAP encompassed Plant Vogtle. The calculations performed verify the RCS pressurization rate, the amount of inventory addition capable by gravity flow from the refueling water storage tank (RWST) to the RCS, and the adequacy of vent openings in the RCS to relieve RCS pressure buildup. The RCS mid-loop water level instrumentation was studied to determine its response to the different system effects including the effect of draindown.

Section 3 of this report investigated the feasibility of continuing work inside containment once boiling begins within the reactor vessel and creates a steam environment within the containment. Calculations were performed to determine the amount of time required to receive a radioactive dose equal to the maximum allowable individual maximum permissible concentration (MPC) and the number of containment coolers needed to keep the containment temperature below 160 °F for the 57 min prior to core uncovery.

Section 4 of this report reviewed GL 88-17 and the response letters to ensure all six program enhancements recommended by the NRC have been adequately addressed.

1.0 REVIEW AND PERFORM PLANT SPECIFIC ANALYSIS

1.1 GENERAL DESCRIPTION OF REVIEWS AND ANALYSIS

Plant Vogtle operational procedures were reviewed for changes which incorporated information found in WCAP-11916. Procedure 18019-C, "LOSS OF RHR," contains steps and cautions obtained from information in WCAP-11916. This information includes the time to core uncovery, time to boiling, heatup rate, and RCS gravity fill from the RWST. All of this information except the last item is discussed in this section. The last item will be discussed in Section 2 of this report. Because this specific information is used for plant operation, it was necessary to verify that the WCAP, which analyzed generic two, three, and four loop plants, encompasses Plant Vogtle. The results of these reviews are in Section 1.3.

The WCAP analysis list 13 assumptions for the generic study. All of the assumptions except the decay heat power, encompass Plant Vogtle. Since the fuel modeled in the WCAP was 12-month cycle fuel and Vogtle uses 18-month cycle fuel, this assumption needed verification.

WCAP-11916 assumes a generic four-loop 17 x 17 fuel plant with a thermal power of 3700 MW and a core average burnup of 30,000 MWd/MTU. Even if Plant Vogtle was uprated, the power level would be a maximum of 3565 MW. The decay heat generation rate essentially increases linearly with power level. Considering the planned fuel management strategy, the core average burnup at Plant Vogtle could approach 40,000 MWd/MTU. Increases in burnup above the 30,000 MWd/MTU level increase the decay heat rate only slightly. For Plant Vogtle, the decrease in decay heat rate due to a lower power level is significantly larger than the small increase due to increased burnup. Therefore, there is reasonable margin between the WCAP results and any expected mode of operation at Plant Vogtle. Also, the results of an evaluation of the Vogtle decay heat source using the NRC Branch Technical Position ASB 9-2, Rev.2, July 1981, showed the WCAP and Vogtle models to be very close (Attachment 1). Although neither model bounded the other at all times after reactor shutdown, the differences between the two models was small compared to the margin between the assumptions in WCAP and Plant Vogtle's core average burnup. Based on these findings, the decay heat generated by each unit at Plant Vogtle will always be bounded by the results of WCAP-11916.

Using the WCAP decay heat source, calculations were performed using conditions at 48 hours after shutdown for comparison with the findings of the WCAP. The calculations performed were time required to saturation, time required to expose the core, and RCS heatup rate. To ensure that no geometrical differences between the WCAP model and Plant Vogtle affected calculation results, the inventory volume for Vogtle was calculated. Comparisons of the plant specific calculation to the WCAP findings are discussed in Section 1.3.

A brief history and structure of the MAAP computer program along with a description of its mid-loop analysis capability are presented in Attachment 2.

1.2 PLANT SPECIFIC CALCULATIONS

This section develops Plant Vogtle-specific data for comparison with data and results from WCAP-11916. The methods suggested in WCAP Section 3.10 for calculating plant-specific data were used as general guidance.

1.2.1 TIME REQUIRED TO SATURATION

The assumptions used in this calculation are listed below. Assumptions used in the WCAP were also used for this calculation.

1. Initial condition for pipe, vessel and water is 140°F.
2. Water elevation is 187 ft-0 in (mid-loop conditions).
3. Uprated power is used (3565 MWt).
4. WCAP-11916, Figure 3.2.4-1 "Decay Heat Power vs Time After Shutdown," applies to Vogtle.
5. Power level used is for 48 hours after shutdown (per WCAP).
6. Water volumes used for time to saturation include the core region, upper internals region, and 30% of the hot legs. Volumes used for time to core uncovery include upper internals region, hot and cold legs, surge line, and a portion of the reactor coolant pump (RCP) bowl and RCP suction line.
7. Solid heat capacities for the thick vessel metal sections will not be included for conservatism.
8. Heat loss through insulation is conservatively left out.
9. All residual heat remover (RHR) cooling and flow is lost at time t=0 min.
10. RCS openings include the pressurizer (PZR) manway during heatup and a steam generator (SG) manway during boiling.
11. Containment and (RCS) are at atmospheric pressure.
12. SGs are not available for cooling.

Using WCAP figure 3.2.4-1 and uprated fuel for Vogtle, the decay heat rate for Vogtle is

$$(3565 \text{ MWt})(.0048) = 17.11 \text{ MWt or } 16{,}230 \text{ Btu/s } (973{,}800 \text{ Btu/min}).$$

With an RCS initial water temperature of 140°F, and a final water temperature of 212°F the temperature increase for the scenario is 72°. Because different water volumes and heat capacities are needed for all of the calculations, the RCS was divided into separate regions for analysis. The regions are shown in Figure 1.1.

The total volume of the core region is

$$[(\pi/4)(152.5 \text{ in.})^2(160.5 \text{ in.})]/12^3 = 1696 \text{ ft}^3.$$

From FSAR section 4.1 and 4.2, the fuel volume is

$$[(151 \text{ in.})(\pi/4)(0.374 \text{ in.})^2(264 \text{ rods})(193 \text{ assemblies})]/12^3 = 489 \text{ ft}^3.$$

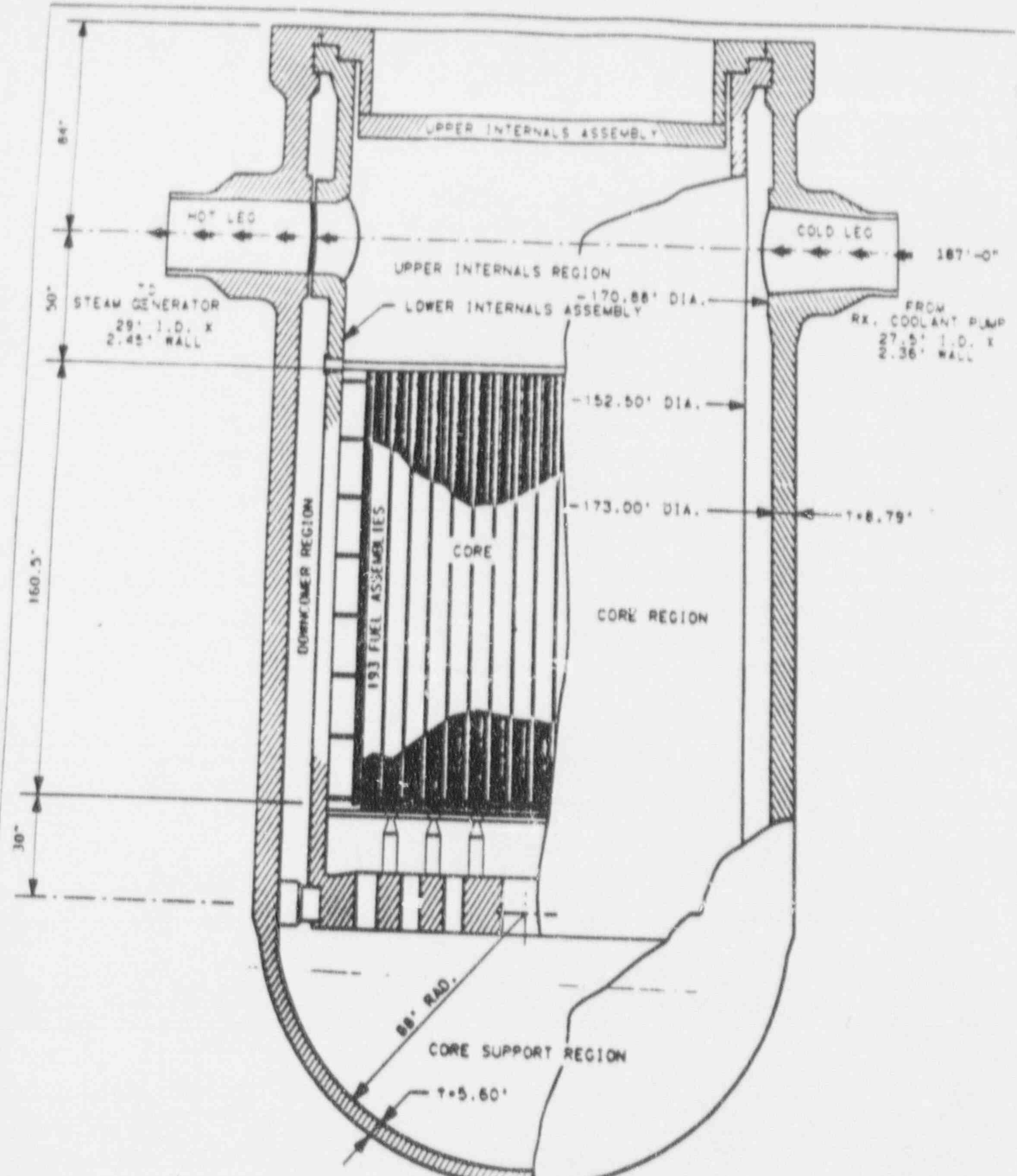


FIGURE 1.1 HEATUP - VOLUME REGIONS

From FSAR table 9.1.5-3, the lower internals weight is 260,000 lbm. Using the 501.3 lbm/ft^3 as the density of stainless steel, the volume of the lower internals is

$$(260,000 \text{ lbm})(501.3 \text{ lbm}/ \text{ft}^3) = 519 \text{ ft}^3.$$

About 30 percent, or 155 ft^3, of the lower internals volume is estimated to be in the core region, with a solid heat capacity of 9324 Btu/lbm-F. The weight of UO_2 and clad in the core region are 222,739 lbm and 45,296 lbm, respectively, from FSAR Table 4.3.-1. The specific heat (Cp) for fuel is 0.06 Btu/lbm-F and for Zircalloy-4 clad is 0.081 Btu/lbm-F.

Therefore, subtracting the fuel and metal volumes from the total volume, the core region water volume is

$$1696 \text{ ft}^3 - 489 \text{ ft}^3 - 155 \text{ ft}^3 = 1052 \text{ ft}^3$$

with a solid heat capacity of

$$(222,739 \text{ lbm})(0.06 \text{ Btu/lbm-F}) + (45,296 \text{ lbm})(0.081 \text{ Btu/lbm-F}) = 17,033 \text{ Btu/F}.$$

The total volume of the core support region is

$$[(4\pi/3)(88 \text{ in.}/12)^3(0.5)] + [(\pi/4)(152.2 \text{ in.}/12)^2(2.5 \text{ ft})] = 1143 \text{ ft}^3.$$

About 35 percent, 182 ft^3, of the lower internals volume is estimated to be in the core support region. The weight of the lower internals is 260,000 lbm, with a specific heat capacity of 0.12 Btu/lbm-F.

Therefore, the core support region water volume is

$$1143 \text{ ft}^3 - 182 \text{ ft}^3 = 961 \text{ ft}^3$$

with a solid heat capacity of

$$(260,000 \text{ lbm})(0.12 \text{ Btu/lbm-F}) = 31,200 \text{ Btu/F}.$$

The total volume of the upper internals region to the 187 ft-0 in. elevation is

$$[(\pi/4)(152.5 \text{ in.})^2(50 \text{ in.})]/12^3 = 528 \text{ ft}^3.$$

From FSAR table 9.1.5-3, the upper internals weight is 132,000 lbm. The total volume is calculated to be 264 ft^3. About 15 percent of the lower internals volume (79 ft^3) is estimated to be in this region.

Therefore the upper internals region water volume is

$$528 \text{ ft}^3 - 79 \text{ ft}^3 = 449 \text{ ft}^3,$$

with a solid heat capacity of

$$(132,000 \text{ lbm})(0.12 \text{ Btu/lbm-F}) = 15,840 \text{ Btu/lbm}.$$

The total volume of the downcomer region is

$$[(\pi/4)((173\text{in.})^2 - (152.5\text{in.})^2)(210.5\text{in.})]/12^3 = 638 \text{ ft}^3$$

which is also the water volume of this region.

The four cold leg pipes and nozzles have a 27.5-in. inside diameter and are each 27 ft long. The four hot leg pipes and nozzles have a 29-in. inside diameter and are each 19 ft long. The total water volume with initial level at the hot and cold leg center line is

$$0.5\ [(\pi/4)(27.5\text{ in.}/12)^2(108\text{ft.})] + 0.5\ [(\pi/4)(29.0\text{in.}/12)^2(77\text{ ft.})] = 400\text{ ft}^3.$$

This is 223 ft^3 cold leg volume and 177 ft^3 hot leg volume. The heat capacities for the hot and cold legs are calculated using all of the pipe metal volume as a heat sink. The solid heat capacity for the hot pipes is 7760 Btu/F.

For the scenario described in the WCAP, the water capacities in the core, upper plenum, and 30 percent of the hot leg are heated to 212 °F. The total water heat capacity is

$$[1052\text{ ft}^3 + 449\text{ ft}^3 + (0.3)(177\text{ ft}^3)]\ (61.35\text{ lbm/ft}^3)(1\text{ Btu/lbm-F})(72\text{ F}) = 6{,}864{,}329\text{ Btu.}$$

The heat capacity for the fuel and clad over the 72 degree temperature rise is

$$(17{,}033\text{ Btu/F})(72\text{ F}) = 1{,}226{,}376\text{ Btu.}$$

Combining the fuel and metal heat capacities with the water heat capacity, the time required for the heatup is

$$(6{,}864{,}329\text{ Btu} + 1{,}226{,}376\text{ Btu})/(973{,}800\text{ Btu/min.}) = 8.3\text{ minutes.}$$

1.2.2 TIME REQUIRED TO EXPOSE CORE

This calculation determines the length of time it takes to heat and boil off the water above the top of the core. The boil off volume of water is composed of

1. Hot leg and surge line water volumes.
2. Upper Internals Region water volume.
3. Downcomer water volume above the upper core plate.
4. Cold leg and pump suction water volume above the bottom of the cold legs.

All of the assumptions used in the previous section are valid for this calculation. A spill penalty of 35 percent of the boiloff mass is assumed based on the WCAP analysis.

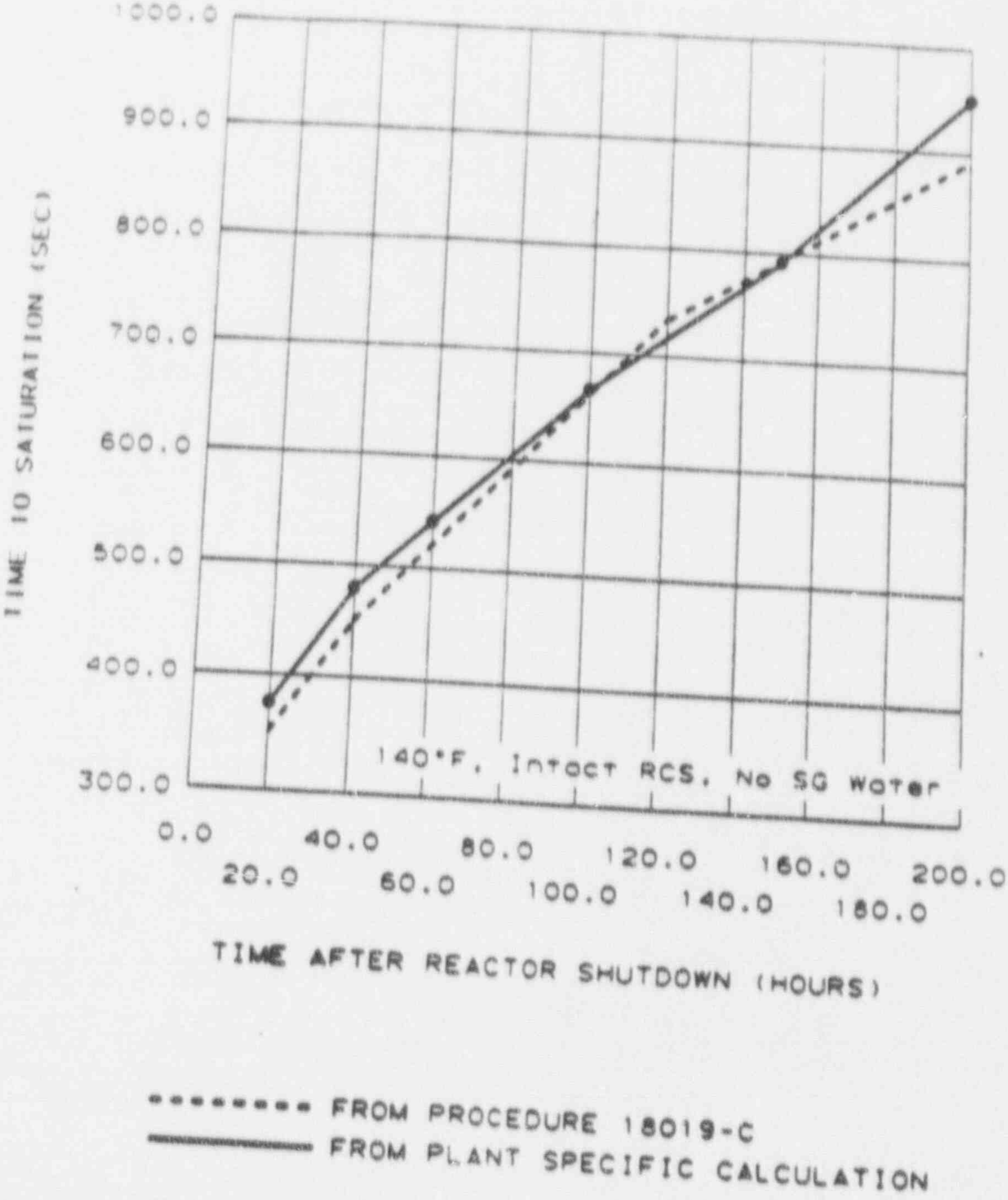


FIGURE 1.2 - TIME TO SATURATION

The hot leg side steam generator elbow water volumes are added to the water volume of the previously computed hot legs. This gives a total water volume of

$$177 \text{ ft}^3 + \pi/4(2.41 \text{ ft})^2(3.3 \text{ ft})(4 \text{ pipes})(1/2) = 220 \text{ ft}^3.$$

The surge line water volume is calculated assuming the line is half full from the entrance up to the second elbow. Therefore the total length of pipe is 22.79 ft and the water volume is 16 ft^3.

The length of the downcomer region with a water volume to be boiled off is 3 ft. The water volume for this region is 109 ft^3.

Each RCP is assumed to have a water volume equal to its inside diameter, 4 ft, times the area of the cold legs. The cold leg steam generator elbow contains water for 1.15 ft. Then, the volume for the RCPs and the SG elbows and cold leg nozzel is

$$\pi/4(2.29 \text{ ft})^2(4 \text{ ft})(4)(1/2) + 20 \text{ ft}^3 + \pi/4(2.58 \text{ ft})^2(1.15 \text{ ft})(4) = 77 \text{ ft}^3.$$

Adding the water volume of the upper internals region, 449 ft^3, the boil off water volume is 1094 ft^3. At 140 ^oF, the weight is 67,150 lbm. Subtracting a 35 percent spill penalty from this gives 43,648 lbm. Using the enthalpies of water at 140 ^oF and saturated steam at 212 ^oF, the decay heat required to heat and boil off this mass is

$$(1150.9 \text{ Btu/lbm} - 107.96 \text{ Btu/lbm})(43{,}648 \text{ lbm}) = 45{,}520{,}499 \text{ Btu}.$$

The decay heat required to heat the core region water volume from 140 ^oF to 212 ^oF is

$$(180.16 \text{ Btu/lbm} - 107.96 \text{ Btu/lbm})(64{,}571.76 \text{ lbm}) = 4{,}662{,}081 \text{ Btu}.$$

The total heat capacity of the RCS metal used for heat sinks over the 72 ^oF degree temperature rise is

$$(81{,}157 \text{ Btu/F})(72 \text{ F}) = 5{,}843{,}317 \text{ Btu}.$$

The heat input required to boil-off enough water to expose the core is the sum of all the heat inputs, which is 56,025,897 Btu. The decay energy for 48 hours after shutdown is 16,230 Btu/s The time to boil off is then

$$(56{,}025{,}897 \text{ Btu})/(16{,}230 \text{ Btu/s})(60 \text{ s/min}) = 57 \text{ min}.$$

1.2.3 RCS HEATUP RATE FOR 48 HOURS

To determine the degrees F per minute heatup for 48 hours after reactor shutdown, divide the total degree change by the amount of time required for that change to occur.

$$(72\ ^oF) / (8.3 \text{ min.}) = 8.6\ ^oF/\text{min}.$$

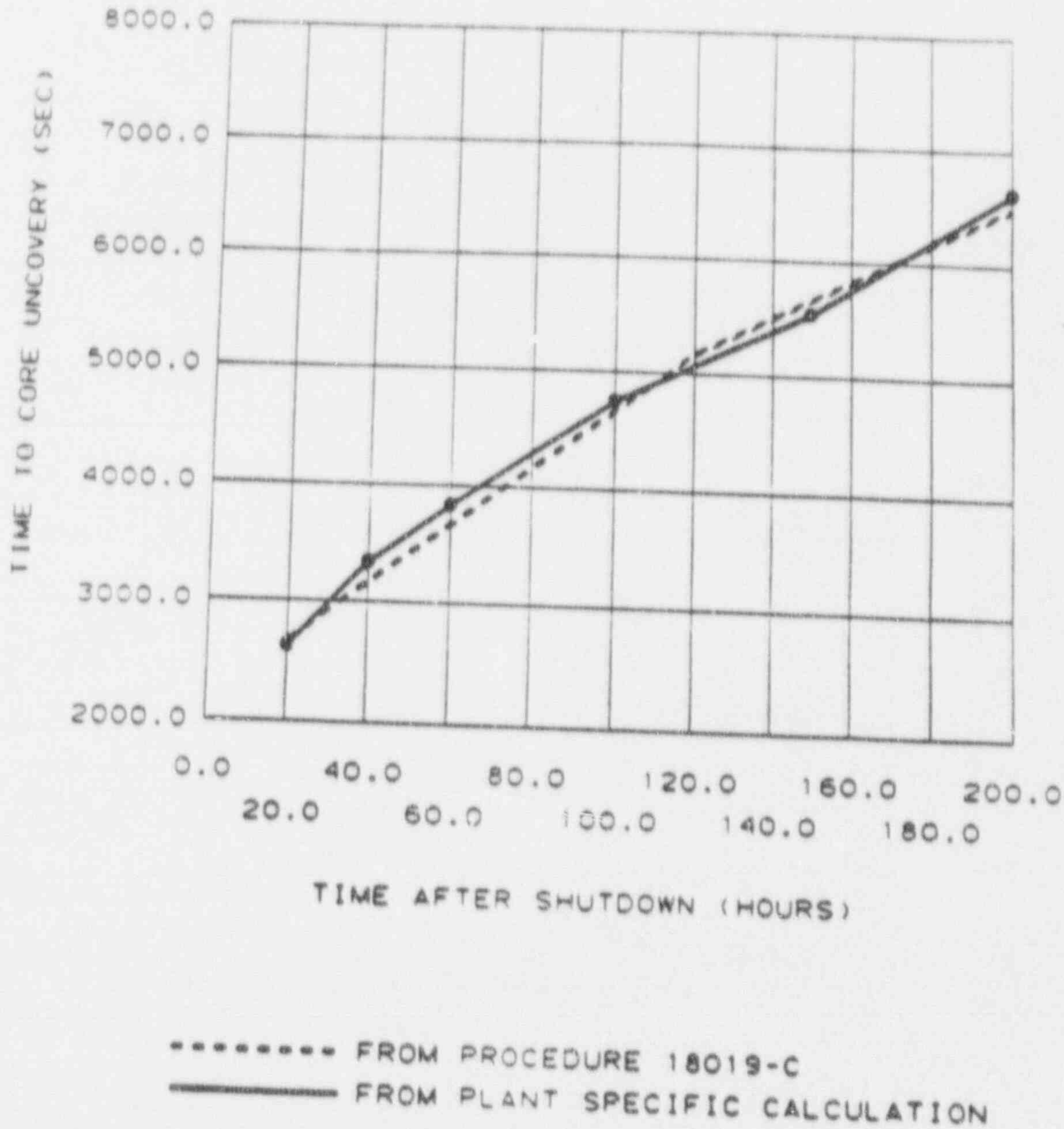


FIGURE 1.3 - TIME FOR CORE UNCOVERY

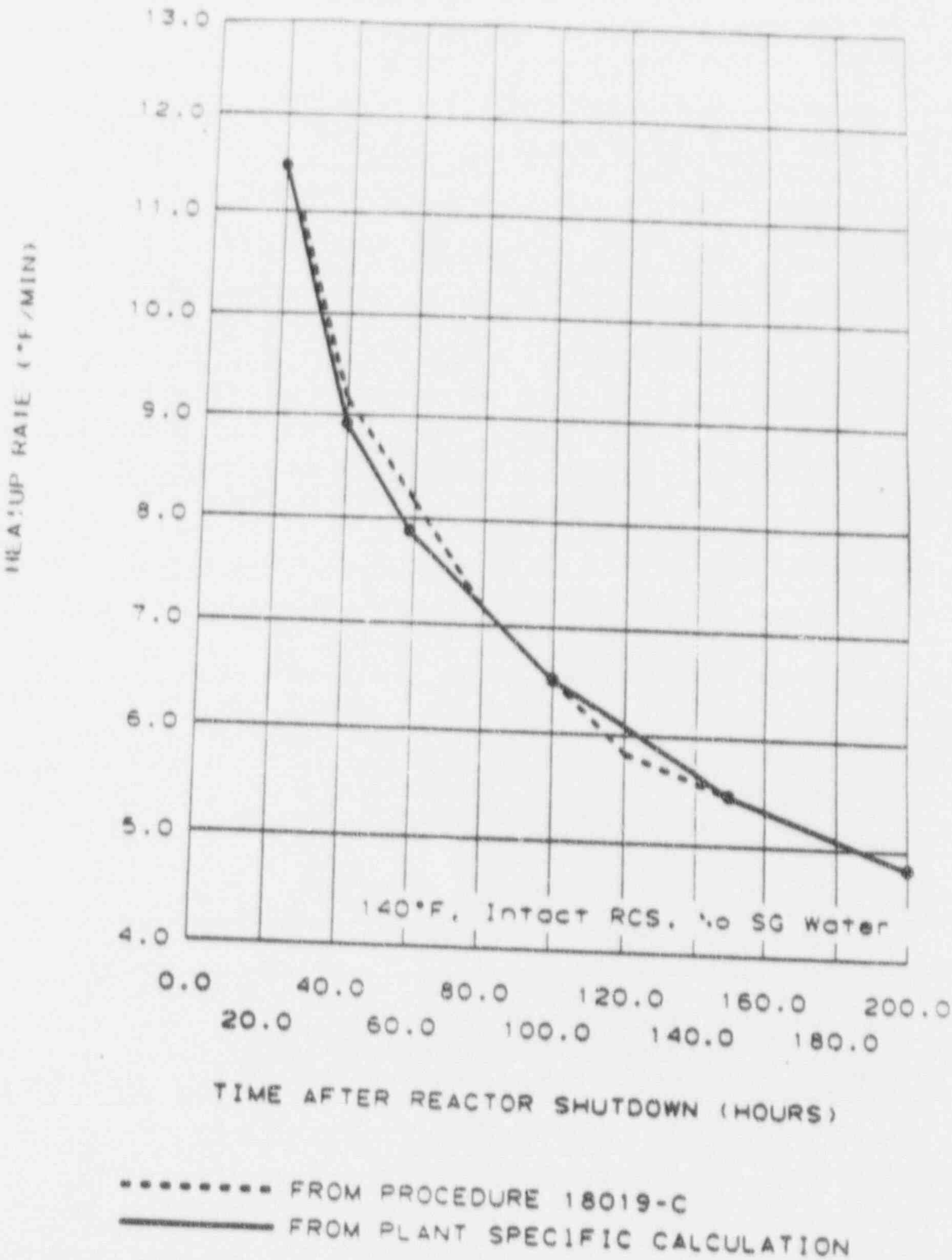


FIGURE 1.4 - HEATUP RATE

1.3 SUMMARY OF CONCLUSIONS

The inputs and assumptions used for the TREAT program are in WCAP section 2.3.4, pages 11 through 14. All of the assumptions used for this generic analysis were verified to be applicable to Plant Vogtle. This includes the assumption about the decay heat power which was studied to ensure that differences in the fuel did not cause significant differences in decay heat power.

Specific calculations were performed to estimate the time to saturation, time for core uncovery, and RCS heatup rate for Vogtle. The WCAP approach considered only heating the water volume directly around the fuel to 212°F which takes approximately 8 min. The plant-specific calculation estimated 8.3 minutes or approximately 8 minutes for this heatup to occur. The heatup rate for this volume of water, upper plenum, and part of the hot legs is estimated to be 8.6 °F per minute. The WCAP estimated a slightly higher heatup rate. After the water is heated, it takes approximately 49 more minutes to boil off the water volume above the core and expose the upper core plate. The WCAP estimated a slightly faster time to core uncovery.

Assuming all of the conditions except the decay heat rate remain the same throughout the scenario, graphical comparisons can be made at various times after shutdown. Curves, plotted in Figures 1.2, 1.3, and 1.4, show the data from the plant-specific calculation on graphs from Procedure 18019-C. The data points shown on the graphs indicate calculation points using the assumption mentioned above. The data for the procedure graphs are from the WCAP generic 4 loop plant analysis. All of the plant-specific curves follow the WCAP curves in the regions for which the specific calculation were performed. Some of the differences in the data can be attributed to the accuracy of computer iterations of several changing conditions such as heat sink conduction and water and vapor volumes. Another difference is that the Vogtle calculations estimate a larger heatup volume and a smaller boil off volume than used in the WCAP analysis. However, the time estimate outcomes do not differ significantly from the graphs used in the Georgia Power Company procedures.

For the information analyzed in this section, only Procedure 18019-C was found to contain information requiring verification. Other procedures will be discussed in subsequent sections.

Since all of the assumptions used in the WCAP computer program are valid for conditions at Plant Vogtle and since the plant-specific calculations correlate to results predicted by the WCAP analysis, the WCAP results discussed in this section encompass Plant Vogtle.

2.0 ANALYSIS OF NONPOWER CONDITION PHENOMENA

2.1 GENERAL DESCRIPTION OF ANALYSIS

The WCAP was reviewed for information and generic calculations relating to nonpower condition phenomena that would affect the operation of the RCS during loss of RHR during mid-loop. The related topic discussed in the WCAP was RCS pressure buildup due to inadequate venting on an intact RCS. A pressure buildup could cause an uncontrolled loss of inventory, allowing the core to become exposed. During this time of pressure buildup, the instrument accuracy could vary which would give false readings to operators. Also, a pressure buildup would limit the types of recovery actions the operators are able to perform, including limitation on gravity flow. Plant-specific calculations were performed on these topics to determine the applicability of the WCAP results for Vogtle. The plant-specific calculations performed were to determine the RCS pressurization rate, the adequacy of different vents used while at mid-loop, inventory addition possible via gravity flow from the RWST, and the accuracy of instrument readings during the different conditions including system draindown.

2.2 PLANT-SPECIFIC CALCULATIONS

This section develops Plant Vogtle specific data for comparison with data and results from WCAP-11916. The methods used in WCAP section 3.10 for calculation plant-specific data were used as general guidance.

2.2.1 RCS PRESSURIZATION RATE

A simplified calculation was performed for general comparison with the WCAP-11916 RCS pressurization analysis. This calculation neglects the effects of air and RCS metal heat sinks and assumes steady-state equilibrium for any given heat input. Despite these limitations, the most important factors in determining the pressure buildup are the plant-specific heat rate and liquid and vapor volumes; therefore, this calculation is useful in examining the general trend of the pressurization. Because of the simplifying assumptions, the calculation should be used for comparison purposes only. Assumptions for this calculation are listed below.

1. Core water temperature is initially at 212°F.
2. Per WCAP-11916, 13 percent of the decay heat generated by the fuel is used to heat core metal.
3. Volume of water in RCS is 12,462 ft^3.
4. The ratio of water to vapor volume does not change significantly over length of time required for RCS pressurization.
5. RCS is intact with no vent openings and no SG with secondary side water. Nozzle dams are not in place.
6. Decay heat for Vogtle fuel is a constant 16230.5 Btu/s.
7. Effects of any noncondensibles are neglected.
8. RCS metal heat sinks are neglected.
9. Steady-state conditions are assumed for any given heat input, i.e., uniform liquid and vapor temperatures.

For this scenario, the first law of thermodynamics will be applied for a system that undergoes a change of state. The control boundary for the system is the entire RCS volume. As the system undergoes a change of state, the only energy to cross the boundary will be the decay heat input by the fuel. Therefore, the net change in the internal energy of the system will be exactly equal to the net energy input by the decay heat.

The reference point for the addition of energy (heat) will be at an RCS temperature of 212°F and time = 0 s, where

$$U_{rcs} = U_f\, m_f + U_g\, m_g$$

$$= (180.11\ \mathrm{Btu/lbm})(3335\ \mathrm{ft}^3/0.016716\ \mathrm{ft}^3/\mathrm{lbm}) + (1077.6\ \mathrm{Btu/lbm})(8927\ \mathrm{ft}^3/26.8\ \mathrm{ft}^3/\mathrm{lbm})$$
$$= 38{,}447{,}423\ \mathrm{Btu}.$$

This is the total internal energy for the system. The decay heat rate for Vogtle assuming 13 percent for core metal heatup is

$$16230.5\ \mathrm{Btu/s} - [(0.13)(16230.5\ \mathrm{Btu/s})] = 14{,}120.5\ \mathrm{Btu/s}$$

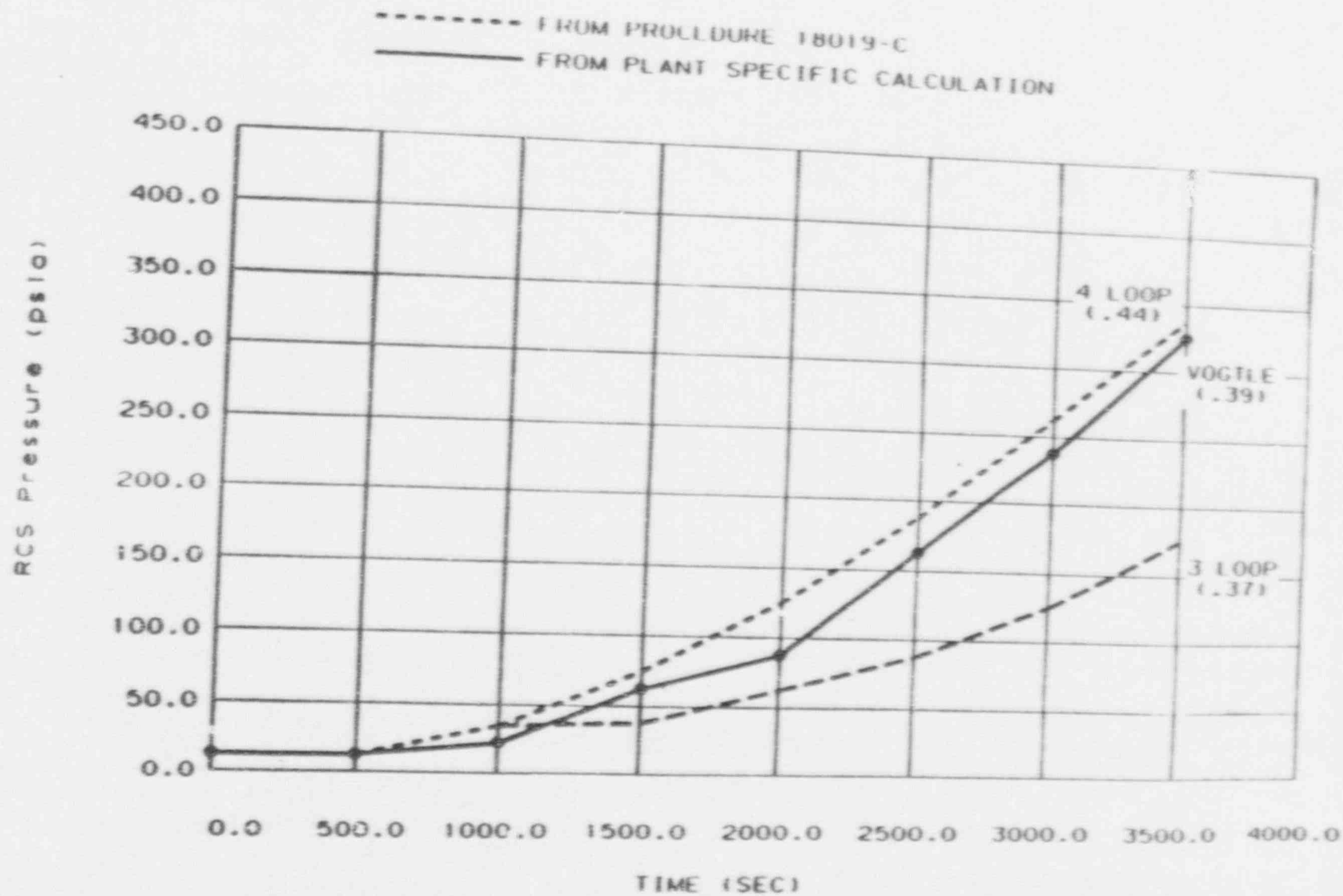
So, for a 500-s interval, the energy input into the boundary is 7,060,268 Btu. Then, the total internal energy for the system after 500 s is 45,507,691 Btu. Since the internal energy is now known, thermodynamic properties can be substituted into the energy balance equation

$$U_{500} = U_f\ (3535/\ v_f) + U_g\ (8927/\ v_g)$$

to obtain the new states of temperature and pressure. If the properties at 240°F are substituted into the equation, the value for U is 44,219,735 Btu. If the properties at 250°F are substituted, the value for U is 46,132,817 Btu. By interpolating between these two numbers for a U of 45,507,691 Btu, the final temperature is 247°F, which corresponds to a saturation pressure of 28 psig. So after 500 s, the RCS pressure has increased from 14.7 psig to 28 psig.

This method is used for 500 s intervals from the time boiling begins up to 3500 s afterwards.

Figure 2.1 is a plot of this plant-specific data and the generic four and three loop plant WCAP data. Numbers at end of each line are the power to vapor volume ratios described in the WCAP.



FOUR-LOOP AND THREE-LOOP CASE, 48 HRS, INTACT RCS, NO SG WATER, P/Vg

FIGURE 2.1 RCS PRESSURE

2.2.2 GRAVITY FLOW INVENTORY ADDITION

This calculation determines flowrates for gravity flows from the RWST, through different systems, to the RCS. The systems analyzed include the chemical and volume control system normal charging flow path which was mentioned in the WCAP, the CVCS safety injection flowpath, the safety injection system flowpath, and the residual heat removal system cold leg injection flowpath for both units. Assumptions used in this calculation are listed below.

1. All valves in the flowpaths are full open. All needle valves are modeled as throttled globe valves.
2. Pumps are modeled as a reducer and an elbow.
3. Weld-o-lets cause insignificant pressure drops for gravity flow conditions and therefore are not modeled.
4. The RCS water level is at 187 ft-0 in.
5. The RWST is full for each RCS pressure condition. Full was defined as a level just above the minimum level allowed to meet technical specifications.

The initial water level for the RWST was determined by the low alarm setpoint of the tank. The water level in the vessel is 187'-0". All of the pipe from the tank to the entry point in the RCS was modeled for each of the systems in Unit 1. The system for Unit 1 with the highest flowrate was modeled for Unit 2 analysis. To obtain pipe information, the current isometric drawings were used for determining the length of pipe, number of fittings, and elevations. The Bernoulli equation, modified for use with equivalent lengths, was used to determine the flows.

$$Q=[(P_{atm}-P_{rcs}+\triangle Z)/(\Sigma\ fl/2Dga^2 + 1/n^2\ \Sigma\ fl/2Dga^2)]^{1/2}.$$

The variables are as follows:

Q	= total flow
P_{atm}	= atmospheric pressure head
P_{rcs}	= RCS pressure head
$\triangle Z$	= elevation difference
D	= pipe diameter
a	= pipe area
f	= friction factor
l	= equivalent length of pipe
n	= number of pipe branches

To determine the equivalent length of each pipe, the number of elbows, tees, valves, and pipe enlargements and contractions were counted. The number of elbows, tees, and valves were multiplied by the appropriate value for their pipe size. All equations are from Crane Technical Paper 410.

For the Safety Injection System, the pipe information is:

Pipe Size (ft)	Area(ft^2)	Equivalent Length (ft)	Friction Factor
24" (1.885)	2.7921	344.75	0.012
10" (0.729)	0.4176	311.08	0.014
8" (0.665)	0.3474	303.58	0.014
6" (0.505)	0.2006	294.92	0.015
4" (0.318)	0.0798	553.50	0.018
3" (0.255)	0.0513	5.00	0.018
2" (0.172)	0.0233	262.25	0.019

These data include the computations for the pump and FE-922. To determine the flowrate when the RCS pressure is 30 psig (69.2 ft) input the pipe data into the flow equation.

$$Q = [(0 - 69.2 + 81.4)/(10.67 + 141.75)]^{1/2} = 0.282 \text{ ft}^3/\text{s}$$
$$= 127 \text{ gal/min.}$$

This same method is used for pressures of 0, 10, 20, and 35 psig.

For the chemical volume and control system (SI mode) the pipe information is:

Pipe Size (ft)	Area(ft^2)	Equivalent Length (ft)	Friction Factor
24" (1.885)	2.7921	601.25	0.012
8" (0.665)	0.3474	361.84	0.014
6" (0.505)	0.2006	199.75	0.015
4" (0.287)	0.0645	793.08	0.017
3" (0.218)	0.0375	213.83	0.018
1.5" (0.111)	0.0097	515.00	0.021

These data include computations for the pump, FE-917, FE-927, and the needle valves throttled to approximately 30 percent. The branch flow is calculated for the four lines which are used to inject water into the RCS. The branch flow losses are

$$h_b = 1/16 \; (fl/2Dga^2)$$
$$= 1/16 \; (0.021)(515)/2(0.111)(32.2)(0.0097)^2$$
$$= 1005 \text{ sec}^2/\text{ft}^5$$

The flowrate when the RCS pressure is 30 psi is

$$Q = [(81.4-69.3) / (1005 + 234)]^{1/2} = 0.099 \text{ ft}^3/\text{s}$$
$$= 45 \text{ gal/min.}$$

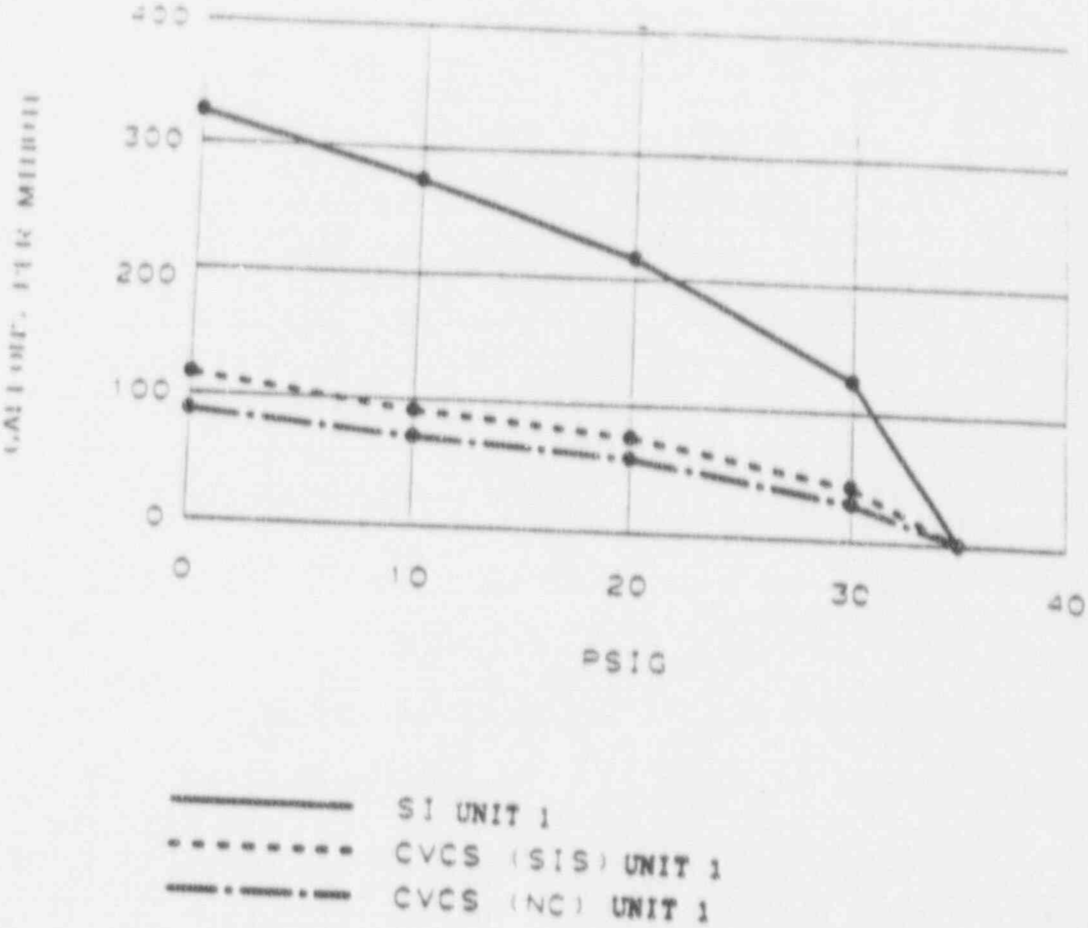


FIGURE 2.2 GRAVITY FLOW for CVCS and SI

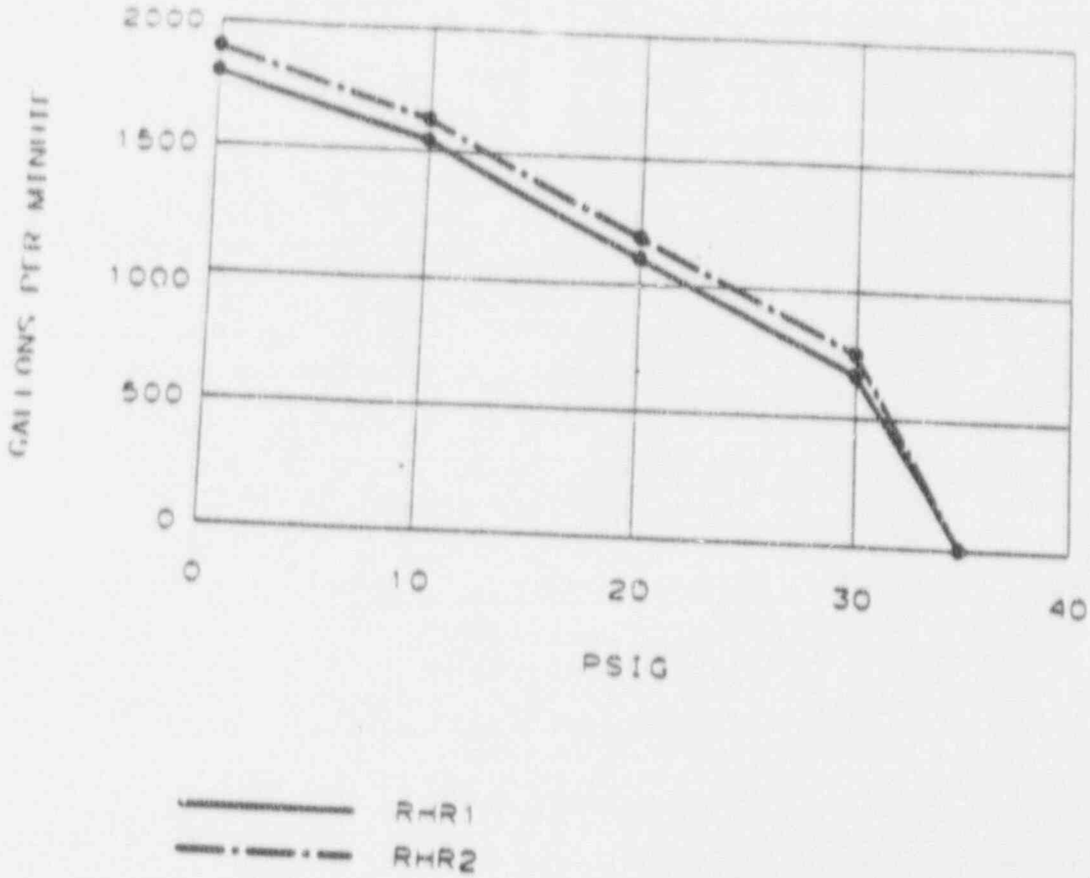


FIGURE 2.3 GRAVITY FLOW for RHR UNITS 1 and 2

2.2.3 RCS VENTING

This calculation is for the case where the RCS has a hot leg vent path. Possible vent paths can be created by removing a SG manway, pressurizer manway, or all three safety relief valves from the pressurizer. The hot leg vent size is adequate if the steam generated by the inventory boiling due to decay heat is able to pass through the opening without substantial pressurization of the RCS. The pressure buildup for venting through the safety relief valve lines and the pressurizer manway will be calculated to see if they are sufficient to relieve the pressure buildup. Assumption and criteria for this calculation are

1. All three PSVs or the PZR manway have been removed.
2. Containment is at atmospheric pressure.
3. Rated power of the reactor is 3565 MWt.
4. Decay heat is 0.48 percent of rated power.
5. RHR is lost 48 hours after reactor shutdown.
6. No line is filled or partially filled with water. (The water level has already been decreased to a level corresponding to the bottom of the hot leg.)

To verify the vent capacity, a pressure in the vessel is assumed and the pressure drops in the system are computed. A final pressure is then calculated and compared to the initial pressure. This comparison is done for verification.

The first calculation is for venting through the safety relief valves, and an initial pressure of 10 psig (25 psia) was chosen. There are 11.5 ft of 29-in. ID hot leg piping to the surge line with an entrance (RV nozzle) and a fitting (Tee) as minor losses. From steam tables, the specific volume of the steam is 16.301 ft^3/lbm and the latent heat of evaporation is 952.1 Btu/lbm. The mass flowrate is 17.05 lbm/s Therefore the volumetric flowrate is

$$q = (17.05 \text{ lbm/s})(16.301 \text{ ft}^3/\text{lbm}) = 277.93 \text{ ft}^3/\text{s}$$

Using this flow to calculate a Reynolds Number and a friction factor(f), solving for the total minor losses (K) gives

$$K = f\ L/D = (0.013)(11.5 \text{ ft}/2.42 \text{ ft}) = 0.062.$$

The pressure drop for the hot leg is then

$$\text{delta P} = [3.62\ (K)(\text{density})(q)^2]\ /\ d^4$$

$$\text{delta P} = [3.62\ (0.062)(0.061 \text{ lbm/ft}^3)(277.93 \text{ ft}^3/\text{s})^2\ /\ (29^4 \text{ in}) = 0.02 \text{ psid.}$$

The pressure at the inlet to the surge line is

10.0 psig - 0.02 psig = 9.98 psig,

or still about 10 psig.

From the hot leg pipe to the 16 in. x 14 in reducer in the surge line, there are 37.84 ft of 12.812 inch ID pipe, a flush entrance nozzle with an assumed sharp edge, a bend with a radius of 6.667 ft, a bend with a radius of 7.167 ft, and the reducer. The total K value and the pressure drop are 1.48 and 0.91 psid respectively. This produces a pressure at the start of the 14-in. pipe of 9.07 psig.

For 9.07 psig, the specific volume of steam is 16.936 ft^3/lbm which gives a new volumetric flowrate of

$$q = (17.05\ lbm/s)(16.936\ ft^3/lbm) = 288.76\ ft^3/s$$

From the reducer to the PZR there are 7 ft of 11.188 in. ID pipe, one bend with a radius of 5.833 ft, and one exit nozzle. The total K value and the pressure drop are 1.33 and 1.54 psid, respectively. This produces a pressure at the entrance to the PZR of 7.53 psig. For 7.53 psig, the specific volume of steam is 18.373 ft^3/lbm which gives a new volumetric flowrate of

$$q = (17.05\ lbm/s)(18.373\ ft^3/lbm) = 313.26\ ft^3/sec.$$

The PZR is assumed to be a 24-in. pipe. This is justified to allow for a free flow path for the steam from the surge line entrance to the valve exit without interfering with the heaters. The total K value and the pressure drop is 0.34 and 0.02 psid, respectively. This produces a pressure at the exit to the PZR of 7.51 psig.

For each of the three PZR relief valve openings, the volumetric flowrate is

$$(313.26\ ft^3/s)\ /\ (3\ \text{valves}) = 104.42\ ft^3/s\ \text{per valve.}$$

From the PZR to the relief valve flange there are 6 ft of 6-in. schedule 160 pipe, four $90^{o}F$ elbows, and an exit through the flange for each of the valves. The total K value is 2.55. The pressure drop is 7.51 psid, which produces a new pressure at the exit of

7.51 psig - 7.51 psig = 0 psid.

This indicates that a vessel pressure of 10 psig is required to allow the steam flow produced by the decay heat to exit through the relief valve vents. Since the pressure drop over this segment is greater than 10 percent of the upstream pressure, a recalculation is required for the volumetric flowrate. An average of the specific volumes at 0 psig and 7.51 psig is used to compute the flowrate. The new flowrate is then used to find a new pressure drop. The new pressure drop is 9.26 psid, which indicates that the vessel pressure will be less than

10.0 psig - (7.51 psig - 9.26 psig) = 11.75 psig.

In the second calculation, venting through the PZR manway, an initial pressure of 4 psig (19 psia) was chosen. Using the same method as described for the relief valve pressure drops, the pressure in the vessel required to vent the steam produced by the decay heat through the PZR manway will be slightly greater than 4 psig.

2.3 INSTRUMENTATION ASPECTS

Instrumentation has been provided to assist the operator in safely maintaining adequate level in the RCS hot legs during mid-loop and draindown operations. This instrumentation is shown in Figure 2.4. Instrumentation has also been provided to assist the operator in quickly identifying air ingestion in the RHR pumps. A brief description is given below:

Two differential pressure transmitters are connected to the RCS to provide independent level indications in the main control room. One transmitter is connected to the RCS Loop 1 hot leg and provides narrow range indication of the hot leg level. This instrument loop also provides annunciation of low hot leg level. The other transmitter is connected to the RCS Loop 4 hot leg and provides wide range indication from the reactor vessel flange to the bottom of the hot leg. The instrument loops are powered from separate instrument buses to maximize the availability of the indication.

Local RCS level indication is available via two permanent level sight glasses located in the containment building. One of the sight glasses shows the RCS level in the region between the bottom of the pressurizer and the reactor vessel flange. The other sight glass shows the RCS level in the region of the reactor coolant pump seals and the reactor coolant system hot legs. The piping for these sight glasses is connected to the RCS as required during Mode 5 and Mode 6.

Current transducers monitor the 4160-V power feeders to each RHR pump. The output of these transducers is routed to the emergency response facilities (ERF) computer. Historical traces of the pump motor current can be obtained at any ERF computer terminal. The logic associated with the Mode 5 and Mode 6 core cooling critical safety function status trees provides a visual and audible alarm at the ERF computer safety parameter display system (SPDS) console in the main control room if the motor current becomes unstable during Mode 5 and Mode 6 operation. This alarm will alert the operator to take any necessary corrective actions to maintain adequate core cooling.

2.3.1 Level Measurement During Steam Generator Tube Draining

Nitrogen may be injected into the steam generator channel head drains to assist in steam generator tube draining when the RCS level is at the reactor vessel flange (el 194 ft-0 in.). At this elevation, level transmitters, LT11310 and LT11320, will be pegged high. The level can be determined using sight glass LG-10402 and PZR level indicator LI-462. This phase of draining takes place well above the RHR suction nozzles (el 186 ft-7 in.). Any pressure rise due to the introduction of nitrogen will not affect the transmitter readings since the pressurizer and the reactor head are kept at the same pressure by their connections to the PRT. Thus, the reference and sensing lines of the transmitters can cancel out the increase in head.

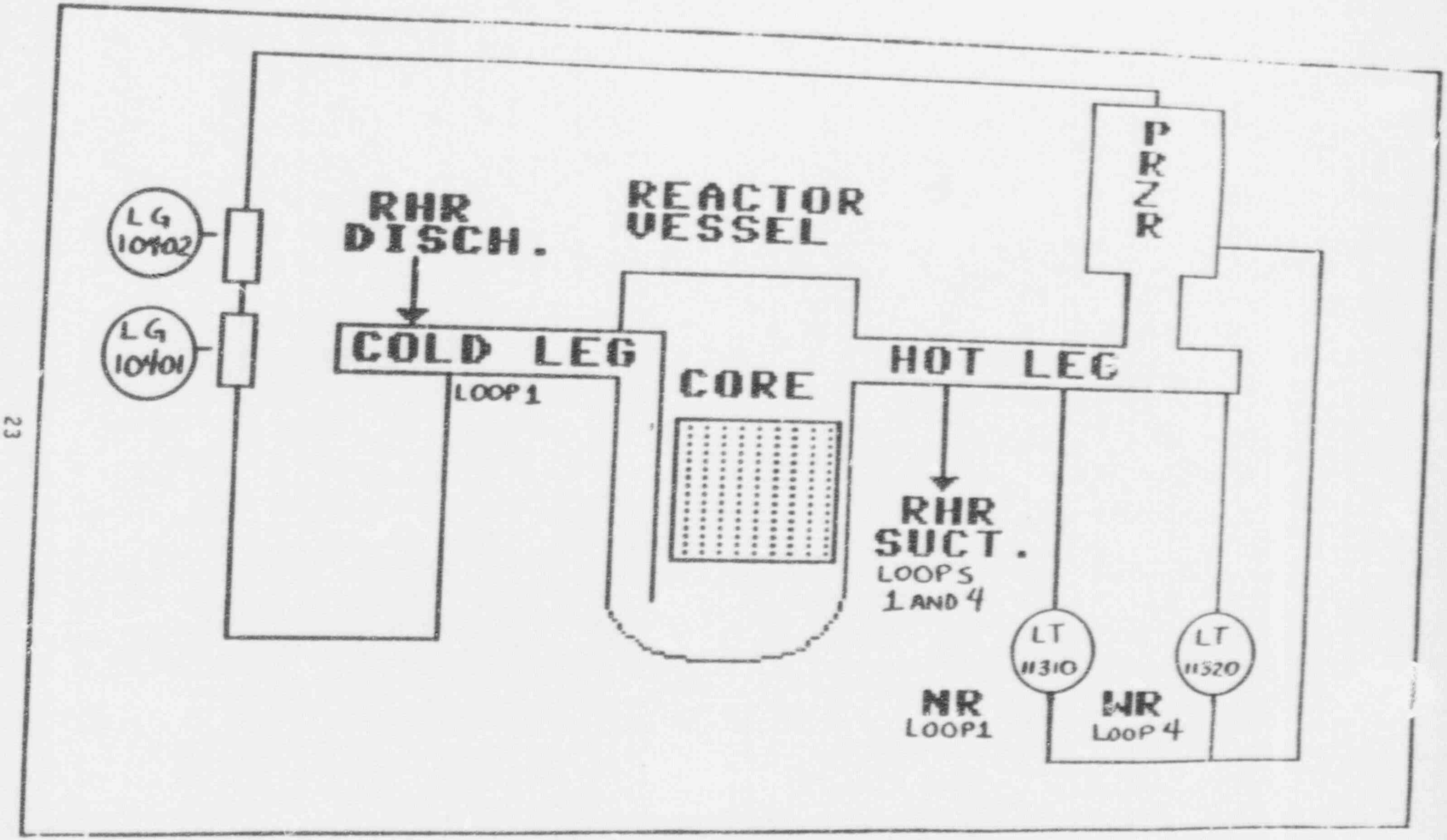


FIGURE 2.4 LEVEL INSTRUMENTATION

During draindown below el 189 ft-0 in., the steam generator tubes begin to drain by gravity. Because there is no vent at the top of the tubes, this draining occurs as random slug flow (also called gurgling). As the slugs of water enter the hot and cold legs they create large swells in the level in the legs. The swells will be seen both on the control room indicators and on the sight glasses; however, the swelled level will not necessarily be equal in the Loops 1 and 4 hot and cold legs since the steam generator tubes drain randomly and independently. During gurgling, the level measurements will be erratic and the low level alarm may activate and clear several times during this period. The operator should use the control room indicator for the transmitter attached to the hot leg being used for RHR suction since the level in this hot leg is critical to maintaining RHR performance. The operator should use the minimum value indicated as the level in the hot leg to ensure that the RHR suction nozzle is covered. The sight glass LG-10401, which measures Loop 1 cold leg level, should not be used to determine level during gurgling unless the transmitters are out of service. Also, during steam generator tube draining it is extremely important that the operators closely monitor RHR parameters including pump flowrate, discharge pressure, and motor current in order to quickly detect loss of pump function should vortexing occur.

2.3.2 Measurement Errors During Mid-Loop Operation

Differential pressure transmitters sense head and, as such, are subject to density differences between the sensing line fill fluid and the density of the process fluid. According to design criteria DC-1505, the ambient temperature in the containment can be as low as 60°F. The pressure gauges used to calibrate the level transmitters will compensate for the ambient temperature at the time of calibration. The water in the RCS will be at approximately 140°F. The difference between the process water density (at 140°F) and the reference leg density (at 60°F) will introduce an error of 1.6 percent (0.5-in.) on the narrow range indicator and 1.6 percent (1.5-in.) on the wide range indicator. During outages where low containment temperatures are expected, this error can be minimized by adjusting the calibrated span of the transmitters as calculated below:

Calibrated Span=(d_{amb}/d_{hl})x(physical span)

where: Physical span= 30 inches for LT-11310, narrow range
Physical span= 96 inches for LT-11320, wide range
d_{amb} = density of water at ambient temperature
d_{hl} = density of water at hot leg temperature

The uncertainty in the transmitter loops due to hardware was determined by a method similar to that used for technical specification surveillance indicators. The hardware-related uncertainties are expected to introduce an error of 3.0 percent (0.9-in.) on the narrow range indicator and 3.0 percent (2.9-in.) on the wide range indicator. Since the hardware-related errors and the process density errors act independently, they can be combined using the "square root sum of the squares" method to obtain an overall indication error.

Narrow range error = (1.6 percent ^{2} + 3.0 percent $^2)^{1/2}$ = 3.4 percent (1.0-in.)

Wide range error = (1.6 percent ^{2} + 3.0 percent $^2)^{1/2}$ = 3.4 percent (3.3-in.)

The error values presented were obtained from calculation X5CP11310.

Static pressure changes in the RCS will have no effect on the transmitters since they utilize a reference leg to cancel out static pressure.

The sight glasses LG-10401 and LG-10402 are also head sensing measurement devices and suffer from density-induced inaccuracies. The density induced errors for various ambient temperatures are shown in Figure 2.5. The error is less than 1/2 in. at mid-loop elevations. This error reads in the conservative direction, i.e., the sight glasses show a lower level than actually exists in the RCS.

Parallax error in reading the meniscus of the fluid in the sight glasses can also cause measurement inaccuracies of around 1/2 in. Because the Loop 1 drain line is used to connect the sight glasses to the RCS, sight glass LG10401 only shows Loop 1 cold leg level, which may not exactly equal the hot leg level under certain conditions, such as steam generator tube draining and loss of RHR.

2.4 SUMMARY OF CONCLUSIONS

When venting through the three safety relief valve openings, the pressure in the reactor could be greater than 10 psig for the steam flowrate to equal the amount of vaporization generated by the decay heat. When venting through the pressurizer manway, the pressure in the reactor could be approximately 4 psig. When a condition exists where there is a large cold side opening, a vessel pressure of 4 psig is great enough to force inventory out of the cold side opening and uncover the core. For Plant Vogtle, this finding does not concur with the finding of the WCAP discussed in section 3.4.2, "Summary of Large Vent Analysis". The WCAP analysis implies that any vent with an area of 0.5 ft^2 or larger is adequate to prevent RCS pressurization. An upper plenum pressure of 4 psig along with a large cold leg opening and a hot leg vent path located in the PZR could cause the water level to go below the upper core plate. This result indicates that only a SG manway vent is adequate when a large cold leg opening exists. It is recommended that procedures 12000-C, 12006-C, and 12007-C be reviewed and revised as necessary to reflect these results. Any of the vents presently specified in the GPC procedures are adequate to prevent pressurization that would exceed the working pressure of SG nozzle dams. Also, these vents are adequate to ensure that gravity flow from the RWST can be accomplished.

If vortexing occurs and RHR is lost, the level transmitters and sight glasses will still be usable but will begin to lose accuracy. This loss of accuracy is due to density changes within the RCS and will become more pronounced as the water temperature in the RCS continues to rise. The cold legs will differ from the level in the hot legs due to heating in the core; therefore, the level transmitters should be used in lieu of the sight glasses. If RCS level drops below the reactor vessel hot and cold leg nozzles, the transmitters and the sight glasses will not offer any information on the level of water above the core. The operable incore thermocouples will provide temperature information which will indicate localized steam voids. The temperature information cannot be easily corroborated or cross checked by the operator and, therefore, will probably be of little use. During recovery operations, water injected into the RCS may cause false level readings on the indicators and the sight glasses, but once the RCS has stabilized from the injection operations, the level indicators and sight glasses may be used to determine RCS level within their normal accuracies.

While operating with the RCS level below 17% pressurizer level, level transmitters 11310 and 11320 should be used to monitor RCS water level. The narrow range hot leg transmitter will provide the most accurate reading while in midloop. Periodic channel checks between the two transmitters should be done to insure readings are accurate. The transmitters should be considered out of service when the readings differ by more than 7%. The midloop sightglass, LG-10401, should be relied on only if transmitters are out of service because there could be actual level differences between the sightglass and the transmitters.

27

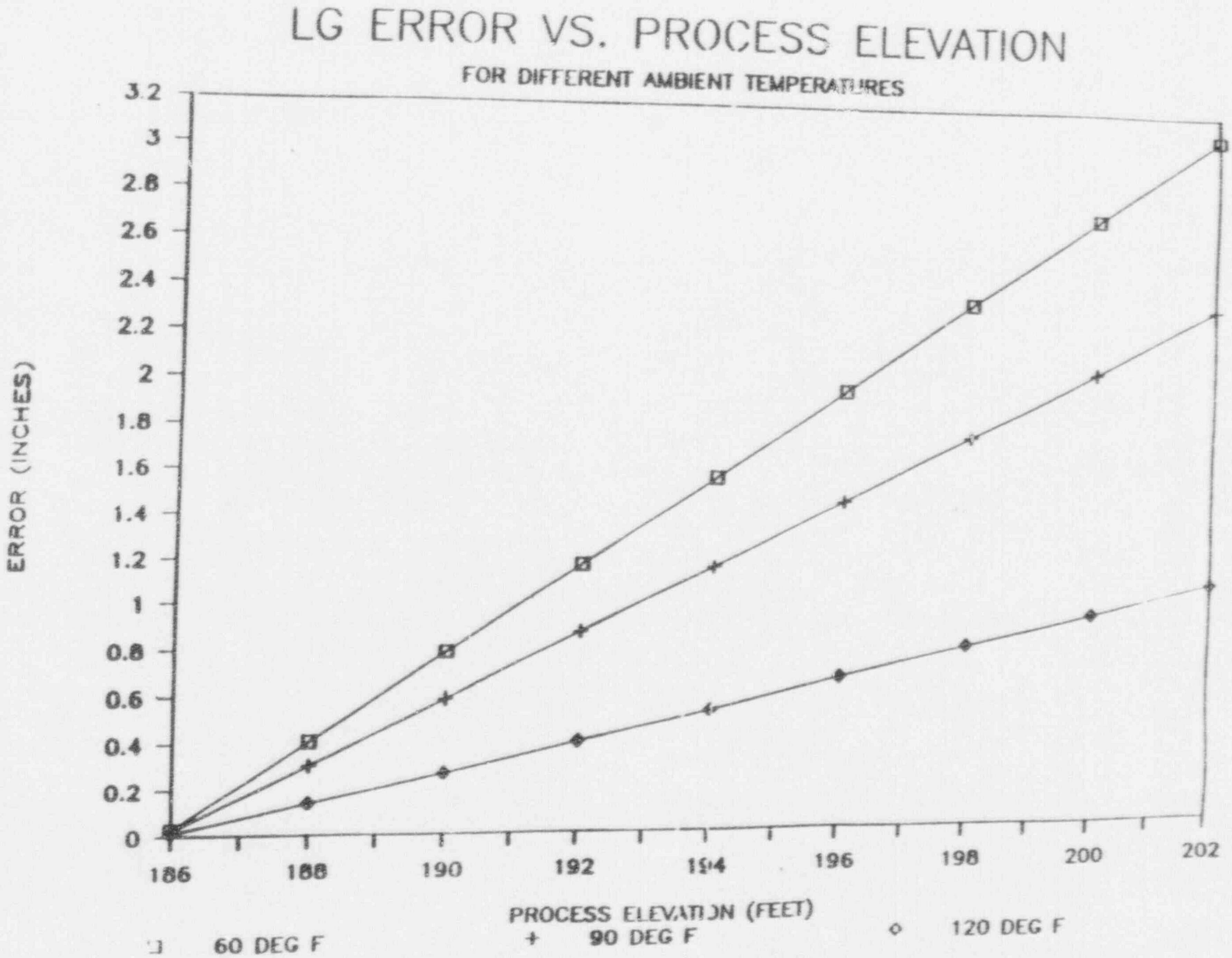


FIGURE 2.5 LEVEL GAUGE ERROR vs PROCESS ELEVATION

3.0 CONTAINMENT ENVIRONMENTAL CONDITIONS

3.1 GENERAL DESCRIPTION OF REVIEWS AND ANALYSIS

Calculations were performed which determined the temperature in containment after a given time, the cooling required for containment to keep the temperature below 160°F prior to the time a core uncovery could result, and the MPC in containment after a given time. The environmental conditions in containment were created using data calculated in Sections 1 and 2 of this report. Information was obtained from plant procedures and plant personnel concerning the requirements for containment closure and physiological limitations for working a harsh environment.

3.2 PLANT-SPECIFIC CALCULATIONS

This section develops Plant Vogtle-specific data for environmental and radiological conditions in containment. The methods used and the results achieved were not developed for comparison with information in WCAP 11916. These calculations were developed to provide a better understanding of conditions that will exist in Plant Vogtle's containment and to aid in determining what changes need to be made to procedures to lessen the consequences of a mid-loop accident.

3.2.1 MID-LOOP CONTAINMENT RADIATION LEVEL

The objective of this calculation is to determine the maximum exposure time in containment before a respirator is required. Assumptions used in this calculation are listed below.

1. The assumptions from Sections 1.2.1 and 1.2.2 apply.
2. The atmosphere in the containment volume above the operation floor is considered to be perfectly mixed at all times.
3. The containment volume used for this calculation is assumed to consist of the clear space above the top of the steam generators plus 80 percent of the gross containment volume between the 220-ft grade and the top of the SG.
4. The air which is expelled from the containment is assumed to contain no radioactivity. This is a conservative assumption and it should be noted that should these conditions exist, there will be a release at ground level directly to the environment.
5. The initial activity at reactor shutdown is considered to be the dose equivalent iodine (DEI) limit specified in Technical Specification 3.4.8. The potential for the occurrence of an iodine spike immediately prior to shutdown is not included because the cleanup systems will rapidly reduce any such spike to within the DEI limit value.
6. Only I-131 is considered in the calculation.
7. The plateout of the iodine on the surfaces of the containment is conservatively ignored.
8. No containment coolers are operational.
9. The containment equipment hatch is open.

The initial conditions are

Steam boiling rate	= 16.72 lbm/sec
MPC of I-131	= 9.00E-09 uCi/cc
Activity limit	= 1.00 uCi/g
I-131 half life	= 8.07 days
Decay time	= 2 days (48 hours after shutdown)
Partition factor	= 0.01
Containment free volume	= 2.26E06 ft^3

The rate of insertion of radioactivity into the containment air is assumed to be equal to the mass transfer rate of the steam multiplied by the partition factor to reflect the tendency of iodine to remain in the water phase.

The steam boiling rate is

(16.72 lbm/s)(453.59 g/lbm) = 7.585E03 g/sec.

The radiation decay factor is

EXP [-0.693(decay time)/(half life)]

EXP [-0.693(2 days)/(8.07 days) = 0.842.

From these, the activity insertion rate can be determined. Multiply the steam boiling rate by the activity limit, the partition factor, and the radiation decay factor.

(7.585E03 g/s)(1.00 uCi/g)(0.01)(0.842) = 63.9 uCi/s

By choosing a time after boiling begins, the activity released during that time can be calculated. If the time is 27 minutes, then

(27 min.)(60 s/min)(63.9 uCi/s) = 1.04E05 uCi

and,

(1.04E05 uCi)/(2.26E06 ft^3)(30.48 cc/ft^3)^3 = 1.62E-06 uCi/cc

is the concentration in containment. Dividing this by 2 gives an average activity of 8.09E-07 uCi/cc for this time period. Since this time period is less than the 40 hours used to calculate the MPC, an adjusted MPC can be calculated for the 27-min time period.

[(9.00E-09 uCi/cc)(40 hrs)]/[(27 min)/(60 min/hr) = 8.00E-07 uCi/cc.

The average activity is then compared to the adjusted MPC to determine if the time chosen allowed for an exposure to the MPC. In this instance, the ratio of average activity to adjusted MPC is 1.011, which indicates the time chosen, 27 min, is the length of time required to receive a radioactivity dose equal to the maximum allowable for the isotope chosen.

3.2.2 CONTAINMENT TEMPERATURE ASSESSMENT

In the event that RHR is lost during midloop conditions and cannot be restored, containment isolation will be initiated. If a large RCS vent path exists, a steam environment will be created inside the containment once boiling initiates within the reactor vessel. To assess the effect of the increased temperature on the containment closure activities, calculations were performed to determine the temperatures that could result. The calculations were divided into separate cases to determine: (1) the time required for the containment atmosphere temperature to reach 160°F after core boiling initiates with no containment coolers operating, and (2) the temperature at 60 minutes after coil boiling initiates for various numbers of containment coolers operating.

The following general assumptions were made for both of the above cases:

1. The contribution to the containment energy of piping motors, lights, and other equipment is assumed to be negligible.

2. The heat sink represented by the massive concrete and steel structures inside the containment is ignored in the calculation. This is a significant conservatism which is partially offset by assumption 1 above.

3. The entire amount of reactor decay heat is assumed to be consumed in the conversion of reactor water at 212°F to steam at that same temperature.

4. The reactor energy is assumed to be the decay heat rate at 48 hours after shutdown from maximum reactor power.

5. The reduction in reactor water volume represented by the removal of the steam through the pressurizer is considered negligible. Thus, the entire mass of steam produced in the boiling process is vented into the containment air space.

6. The initial conditions inside the containment are assumed to be 120°F at 100% relative humidity.

In addition, the following assumptions apply to the first case only:

7. The atmosphere in the containment volume above the operating floor is considered to be perfectly mixed at all times so that saturation conditions exist in the containment atmosphere.

8. The containment volume used for the calculations is assumed to consist of the clear space above the top of the steam generators plus 80 percent of the gross containment volume between the 220 ft grade elevation and the top of the steam generators.

9. The pressures are considered to be constant at one atmosphere in all volumes during the event. This assumption presumes that the containment is open to atmosphere so that sufficient venting of containment air is possible to avoid any significant pressure buildup inside containment.

10. The air which is expelled from the containment is assumed to be at its initial conditions. That is, the vented steam does not mix with the air which is vented. This assumption is conservative in that it precludes the removal from the containment atmosphere of any of the energy from the boiled off steam.

11. No containment coolers are operating.

Utilizing these assumptions, a simplified mass and energy balance was established to determine the approximate time required to reach 160°F with no containment coolers operating and the containment open. The results indicate this time would be 21.5 min.

For the second case, a model was developed to determine the containment atmosphere temperatures at 60 min after coil boiling initiates, with zero, two, three, and four containment coolers operating (zero coolers means that the fans are operating but no cooling water is available). The model performs a mass balance at 5 min intervals to accommodate the steam addition from the RCS boiling. The model assumes saturated atmosphere conditions and performs an energy balance at the end of the 60 minute time span to verify the assumed conditions are reasonable. The following assumptions are utilized, in addition to assumptions (1) through (6) above:

12. The atmosphere in the entire containment volume is considered to be perfectly mixed at all times so that saturation conditions exist in the containment atmosphere. This is reasonable because at least one cooling fan is assumed to be running.

13. The condensation of the released steam is neglected in the calculation. This, in effect presumes the presence of an additional heat source of sufficient size to ensure that the vapor boiled off the reactor remains in the vapor state rather than partially condensing as it warms the containment air.

14. The containment volume used for the calculations is assumed to consist of the entire containment volume.

15. The pressures are considered to be constant at one atmosphere in all volumes during the event. This assumption presumes that the containment is open to atmosphere so that sufficient venting of containment air is possible to avoid any significant pressure buildup inside containment.

16. The air expelled from the containment is assumed to be at the energy condition existing at the end of the previous time step.

17. The containment coolers are presumed to perform at the temperature existing at the start of each time step. The energy removed by the coolers is assumed to be 100% latent heat removal. Thus, the energy removed by the coolers can be used to directly compute the cooler drain flow.

The results are tabulated below and are shown in graphical form in figure 3.1:

With at least one cooler fan running:

Number of Coolers Operating	Temperature in Containment at the following times after start					
	10	20	30	40	50	60
0	139.4	150.8	159.4	166.4	172.0	176.8
2	136.0	144.7	151.2	156.5	160.7	164.3
3	134.3	141.6	147.0	151.3	154.6	157.4
4	132.5	138.5	142.8	146.1	148.6	150.6

It can be seen from the above that a minimum of three coolers would need to be in operation to ensure that containment temperature does not exceed 160^{o}F within 60 minutes.

3.3 SUMMARY OF CONCLUSIONS

The assumptions for the calculations performed in this section were conservative to allow the changes in the containment environment to evolve over time without numerous iterations. The initial conditions of 120^{o}F and 100 percent relative humidity will take some time to develop and the heat sinks present in a massive containment structure will tend to delay the heat up rate. Also, since none of the contamination was modeled as exiting containment, the actual time until MPC limits are reached will be somewhat longer than calculated.

The calculated time for working inside containment without a respirator is 27 min after inventory boiling begins. This is without containment coolers and purge or exhaust fans operating. Personnel inside containment when boiling begins would need to exit containment within 27 min to stay within the MPC for a 40-hour week. The time for continued work inside containment after the 27 min would depend on the condition of the respirators and should be determined by Health Physics.

The calculated time for working inside containment until the temperature reaches 160^{o}F is 21 min without containment coolers operating. At a temperature around 160^{o}F, the air is hot enough to burn the lungs. For work to continue inside an open containment to complete closure activities, all available containment coolers should be operated. At a minimum, three coolers would need to operate to ensure that 160^{o}F is not exceeded prior to the predicted time for core uncovering (57 minutes).

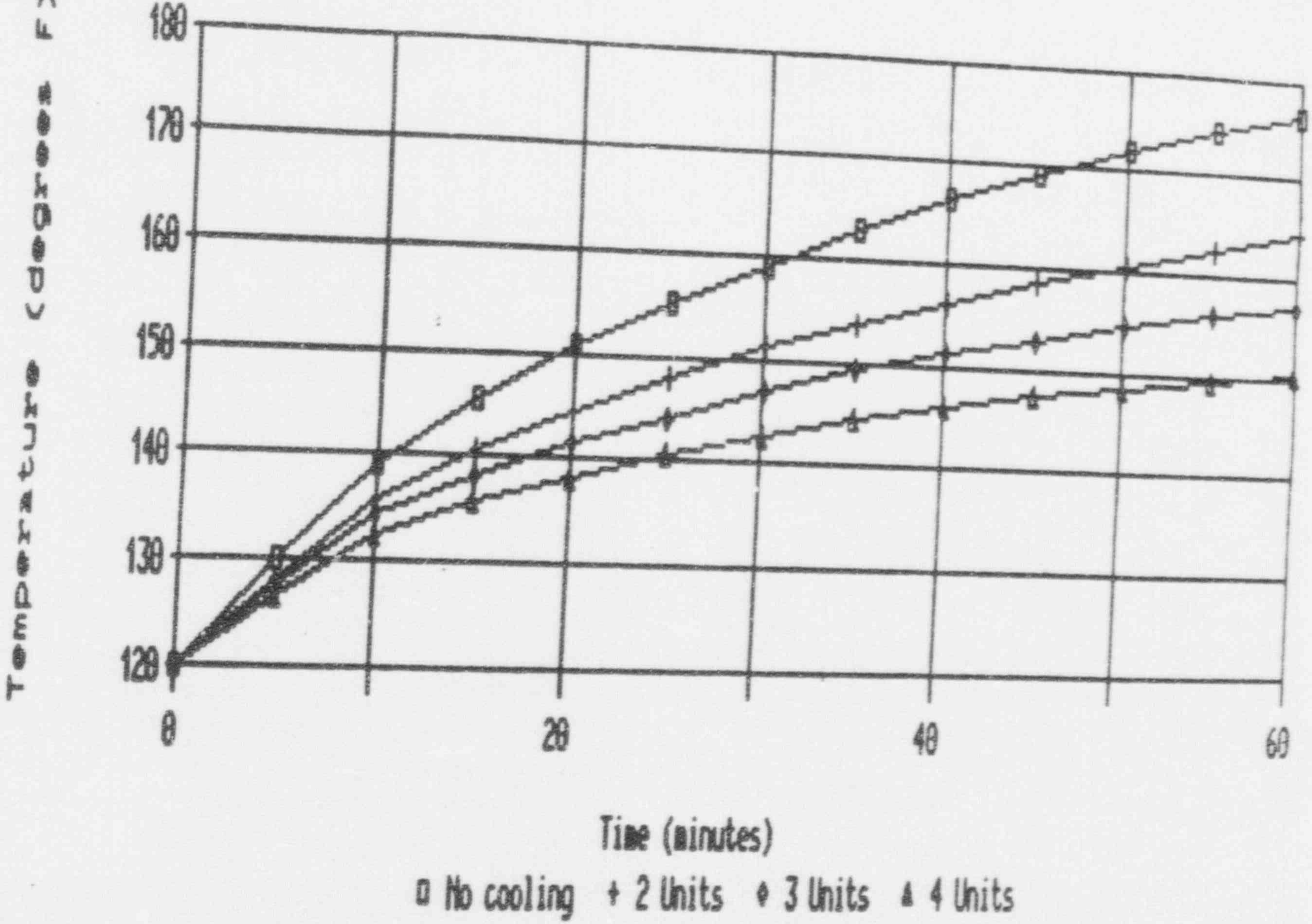


FIGURE 3.1 CONTAINMENT TEMPERATURE vs TIME with COOLERS

4.0 REVIEW OF GENERIC LETTER 88-17

4.1 GENERAL DESCRIPTION OF REVIEW

This section consists of an overall review of Vogtle design and operation in regard to the NRC mid-loop concerns addressed in GL 88-17 and the response letters. The concerns are divided into two groups, expeditious actions and programmed enhancements. Because some of these concerns have been addressed in other documents, only concerns relating to information verified in this report will be addressed. Where applicable, portions of these documents are included as attachments for reference. Documents too extensive to be included are summarized. GL 88-17 is Attachment 3.

4.2 EXPEDITIOUS ACTIONS

In Attachment 1 of GL 88-17, the NRC recommended that eight actions be implemented prior to operating in a condition where the reactor vessel water level is lower than 3 ft below the reactor vessel flange. Georgia Power Company addressed the recommendations of GL 88-17 for Plant Vogtle. The NRC's response to those recommendations is in Attachment 4. Each recommendation/response was reviewed for the possibility of adding information that came out of the WCAP 11916 verification review.

Item 2 of the NRC response addresses the time available for containment closure including those penetrations other than the equipment hatch. Item 2 of the Recommended Action attachment to GL 88-17 requires containment closure prior to the time at which a core uncovery could result from a loss of DHR, coupled with an inability to initiate alternate cooling or addition of water to the RCS inventory. Since the time allowed to close the equipment hatch would also be the time allowed to close other penetrations, the results from Section 2 of this report apply. The time to core uncovery is approximately 57 minutes. If the assumptions used in the calculation apply and the RCS is adequately vented so no upper plenum pressurization occurs, containment penetrations may need to be closed within 57 min of the loss of RHR cooling.

Item 3 of the NRC response addresses the ability to cool containment and the feasibility of continued work within containment once a steam environment exists. Topics 2 and 3 of this report address these concerns. Since, after the loss of RHR, the control room level instruments will provide a more accurate reading than the sight gauge, no operations personnel are required inside containment for monitoring after loss of RHR. If personnel are required inside an open containment to complete containment closure activities, all available containment coolers should be operated to minimize the temperature increase. Provided that mid loop operations start no earlier than 48 hours after reactor shutdown, three coolers at a minimum must operate to ensure that containment temperatures remain below 160°F for 57 minutes after loss of RHR. Maximum permissible dose levels may be reached as early as 27 minutes after core boiling begins for those personnel inside containment without a respirator. To continue containment activities, persons not exposed in the initial 27 minutes could enter containment with a respirator.

Items 3, 4, and 5 on page 2 of the NRC response address lesson plan descriptions. The results of this report support WCAP 11916 findings for Plant Vogtle. Also described in this report are more adequate ways to use the instruments available during a loss of RHR and a computer program that would simulate different scenarios for a Plant Vogtle loss of RHR. This information should aid in developing a more complete understanding of RCS behavior during a loss of RHR accident.

Item 6 on page 2 of the NRC response addresses the effectiveness of openings in the RCS used for venting. Section 2 of this report details specific calculations performed to verify that vents described in Procedure 12006-C, part D4.2.15 (3) are adequate for reliving the steam produced in the RCS. The calculation does not support the use of the safety relief valve piping or the pressurizer manway as hot leg vents if a cold leg opening is present. Pressure buildup in the upper plenum could occur if the pressurizer is used as a vent path. It is recommended that only the SG manway be used for a hot leg vent path if a cold leg opening is present.

4.3 PROGRAMMED ENHANCEMENTS

In Attachment 1 of GL 88-17, the NRC recommends that six programmed enhancements be developed to replace, supplement, or add to the expeditious actions. A preliminary copy of Georgia Power Company's (GPC) plans for addressing these recommendations of GL 88-17 are in Attachment 5. As in the expeditious actions, a discussion of the recommendations/items follows.

Item 1 addresses reliable indication of parameters that describe the state of the RCS and the performance of systems normally used to cool the RCS for both normal and accident conditions. The GPC response discusses an engineering study and a design change development which will satisfy this enhancement. Both of these topics have been completed. The engineering study, REA VG-9010, was completed in June of 1989. Findings from this study were formulated into a Design Change Request and subsequent Design Change Packages 89-V1N051 and 89-V2N052. Implementation of the DCPs is scheduled for the 1R2 and 2R2 refueling outages.

Item 2 addresses the development and implementation of procedures that cover reduced inventory operations. The data incorporated into the GPC procedures from WCAP 11916 will reflect the Vogtle RCS behavior. Examples of this are the graphs from Abnormal Operating Procedure 18019-C which are verified in Section 1 and the adequacy of RCS vents described in Procedure 12006-C and discussed in Section 2 of this report.

Item 4 addresses an analysis to supplement existing information and develop a basis for procedures, instrumentation installation and response, and equipment/NSSS interactions and response. As stated in Enclosure 2, section 3.4 of GL 88-17, WCAP 11916 is an excellent start toward meeting the analysis recommendation. GPC analysis for this item was conducted in REA VG-9011. This report is the product of the analysis and verifies the use of WCAP-11916 at Plant Vogtle. Additionally, a plant-specific calculation was performed to support inventory addition via gravity flow from the refueling water storage tank. The results are reported in Section 2.2.2. Also discussed in item 4 was the special preoperational test (ST-38) performed on Unit 2 which varied RCS level and RHR system flow to determine susceptibility to vortexing. This test is discussed further in the next section.

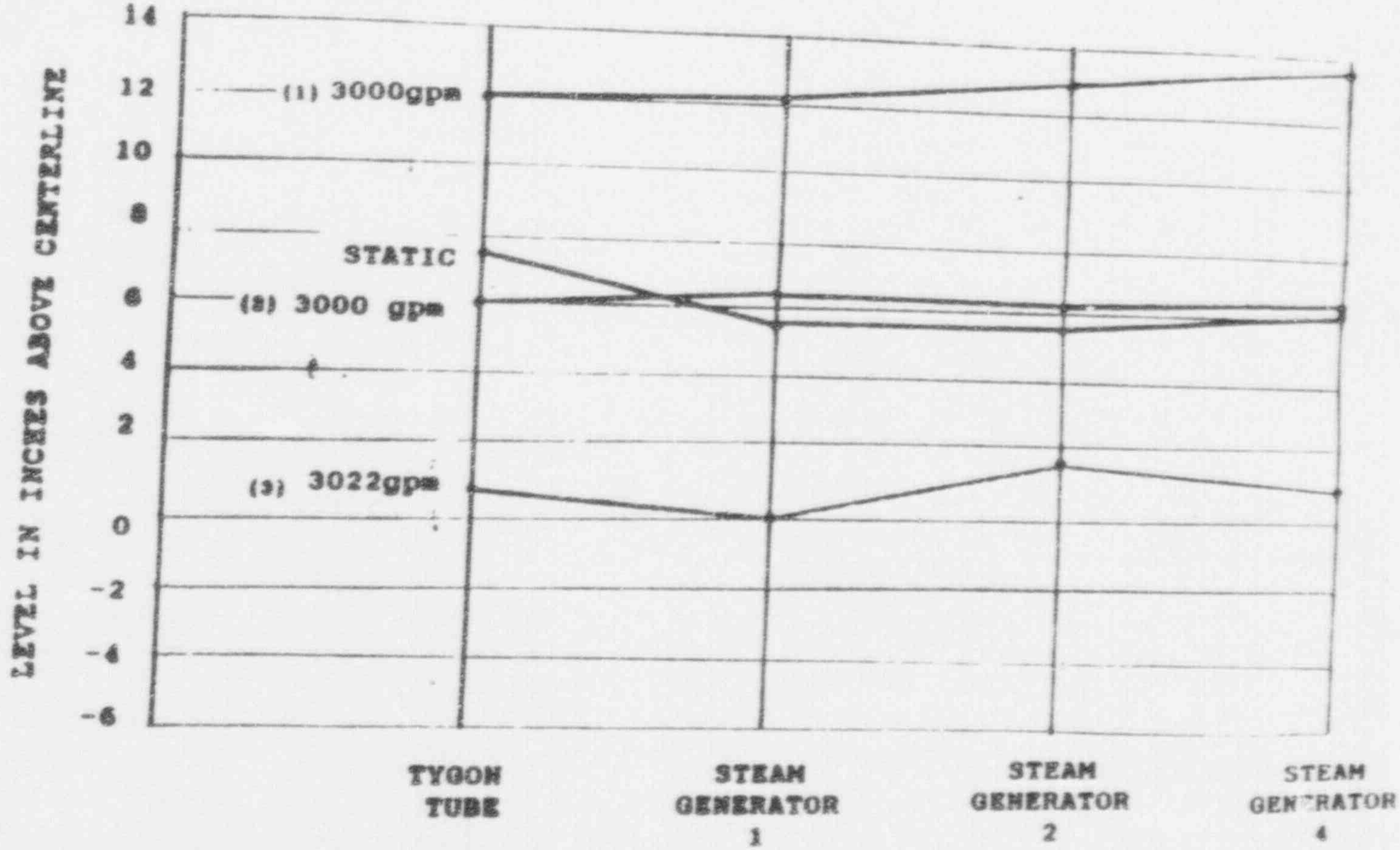
4.4 WCAP-11916 SECTION 2 REVIEW

Westinghouse built a model using dimensional analysis for parameters that are significant in vortex formation. Data recorded during the test for a Vogtle type plant were converted into hot-leg water level as a function of RHR intake flowrate. A graph of these data is shown in Figure 2-14, on page 2-35 of the WCAP. This graph shows that an RHR flow of 3000 gal/min needed a water level of approximately 1 3/4 in. above centerline of the pipe. Westinghouse test data also show that differences in water levels existed between active cold legs, inactive cold legs, active hot legs, and inactive hot legs. The magnitude of level difference was significant—approximately 1 to 2 in.

During startup testing on Unit 2, an RHR flow test, Special Test 38, was conducted to determine the maximum RHR flow that could be achieved at different RCS water levels. Because of the similarities between this test and the test conducted by Westinghouse, the ST-38 procedure and results were reviewed for comparison with the WCAP results.

Using information from the test supervisor, the ST-38 test log, and the WCAP, assumptions about the test procedure such as the RHR valve line-up, the adequacy of time between each test phase for the water level to stabilize, and the placement of the tygon tube connection were verified. With the data from results of ST-38, graphs were constructed to show the water elevations at different points in the RCS. These graphs are in Figures 4.1 and 4.2. The static line on each graph is the water level recorded at each position prior to starting the test. Since no equipment was operating at this time, the static line should be the same elevation at each position. There is a significant level difference between these data points and also between the train A and train B data points.

Information found to explain these differences included MWO 28902165 on valve 2-1201-U4-001, MWO 28900173 on level transmitters 2LT-950A and B, and a MWO on the startup strainers for both RHR pumps. The valve is used for the tygon tube connection. The MWO reported that the valve was difficult to open because valve stem threads were stripped. This would cause the valve not to open, thereby giving a false reading on tygon tube level. The level transmitters which are used to send the water level signal to the control room were also found out of calibration. The startup strainers for both RHR pumps were not removed until after the test was complete. This information makes the test data inconclusive since it is unclear what affect(s) this information would have on the test results. Therefore, the data were not used to verify the results of the Westinghouse test reported in Section 2 of the WCAP.



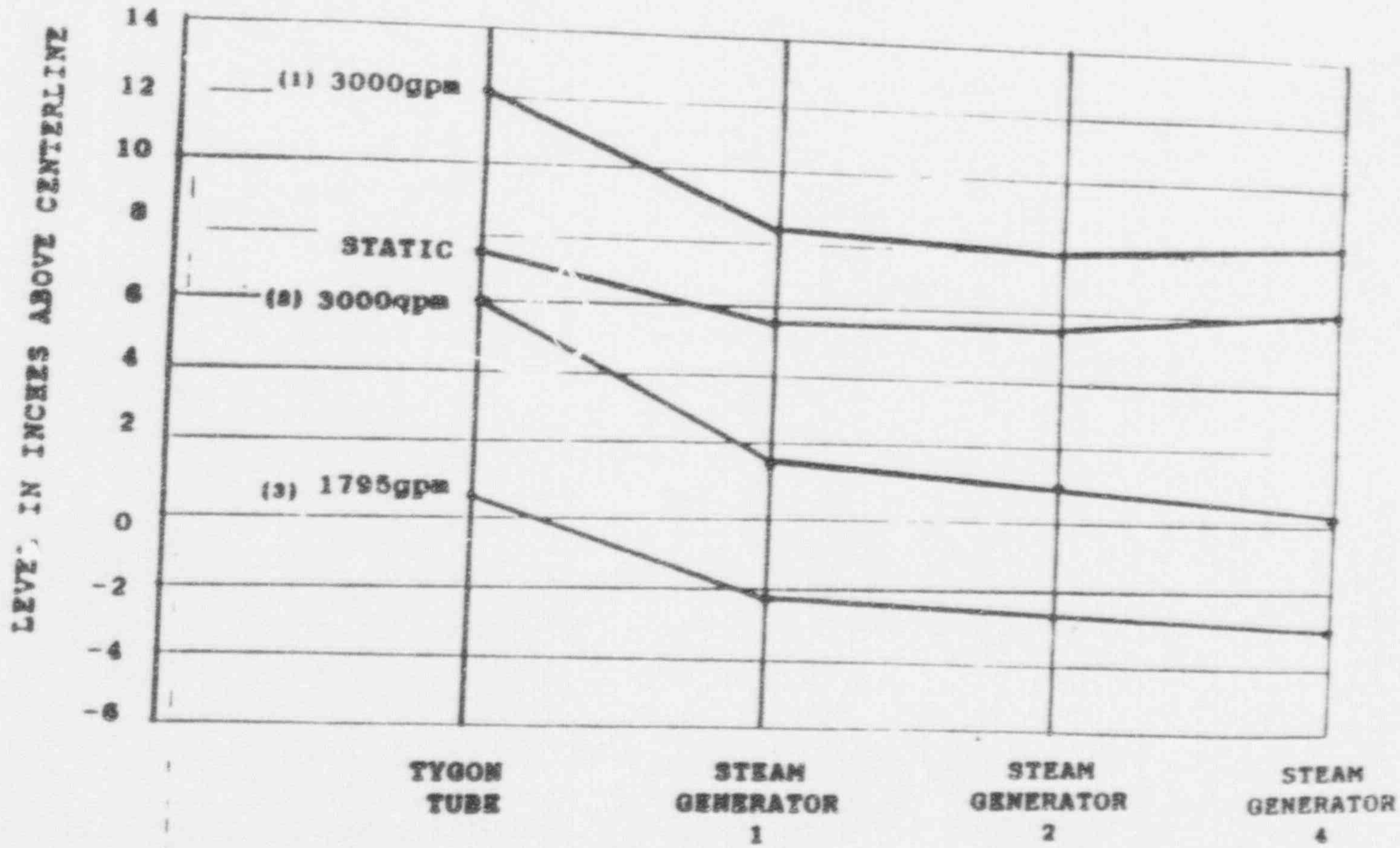
HOT LEG WATER MEASUREMENTS

(1) RCS Performance at 188'-0"

(2) RCS Performance at 187'-0"

(3) Maximum RHR Flow at 187'-0"

FIGURE 4.1 TEST DATA from SPECIAL TEST 38 TRAIN A



HOT LEG WATER MEASUREMENTS

(1) RCS Performance at 188'-0"

(2) RCS Performance at 187'-0"

(3) Maximum RHR Flow at 187'-0"

FIGURE 4.2 TEST DATA from SPECIAL TEST 38 TRAIN B

REFERENCES

1. WCAP-11916, "Loss of RHR Cooling while the RCS is Partially Filled", Rev. 0, July 1988.

2. United States Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Generic Letter 88-17, "Loss of Decay Heat Removal, October 17, 1988.

3. Calculation X4C1201S02, "Mid-Loop Operation - Loss of RHR Radiation Assessment", February, 1990.

4. Calculation X4C1201S01, "Mid-Loop Operation - Loss of RHR Temperature Assessment", February, 1990.

5. Calculation X4C1201S03, "Venting the RCS During Mid-Loop Loss of Cooling", February, 1990.

6. Calculation X4C1201S04, "REA VG-9011 Thermal Analysis and RCS Pressurization Rate", February, 1990.

7. Calculation X4C1201S05, "REA VG-9011 Gravity Flow Units 1 and 2", February 1990.

8. VEGP Nuclear Operations Procedure, 18019-C, "Abnormal Operating Procedure Loss of Residual Heat Removal", Rev. 6.

9. VEGP Nuclear Operations Procedure, 12000-C, "Refueling Recovery", Rev. 15.

10. VEGP Nuclear Operations Procedure, 12006-C, "Unit Cooldown to Cold Shutdown", Rev. 14.

11. VEGP Nuclear Operations Procedure, 12007-C, "Refueling Entry", Rev. 13.

12. VEGP Nuclear Operations Procedure, 13005-1, "Reactor Coolant System Draining", Rev. 9.

13. VEGP Nuclear Operations Procedure, 23985-1, "RCS Temporary Water Level System", Rev. 1.

14. VEGP Unit 2 Special Test Procedure ST-38, "RHRS Operating Demonstration with RCS Partially Filled", Rev. 0.

15. VEGP Drawing 1X6AB02-264, "Reactor General Assembly", Rev. 1.

16. "Response to Generic Letter 88-17", GPC letter log number ELV-00109, file number X7GJ17-V110, December, 1988.

17. U.S. NRC DOCKET Nos. 50-424, 50-425, "Comments on the Georgia Power Company response to Generic Letter 88-17 for the Vogtle Plant, Units 1 and 2 for expeditious actions for Loss of Decay Heat Removal", January 1989.

18. "Response to Generic Letter 88-17", GPC letter log number ELV-00186, file number X7GJ17-V110.

ATTACHMENTS

ATTACHMENT 1

Intracompany Memo

Southern Company Services

DATE: December 15, 1989

RE: Vogtle Electric Generating Plant
Loss of RHR

CAV-NF-260
PC-1431

FROM: R. D. Jones R. D. Jones

TO: W. C. Ramsey

This letter is in response to your October 12, 1989, letter to L. B. Long requesting that PWR Core Analysis confirm that the current and expected Vogtle burnup and power levels are bounding relative to those assumed in WCAP-11916. Further discussions with David Dotson of your SCS Vogtle Support Group were necessary in order to make an appropriate response.

In comparing the expected Plant Vogtle operation to the analyses performed in WCAP-11916, there are two factors which need to be considered. WCAP-11916 assumes a generic four-loop 17x17 fuel plant with a thermal power of 3,700 MW and a core average burnup of 30,000 MWD/MTU. Even if Plant Vogtle is uprated, the power level will be a maximum of 3,565 MW. The decay heat generation rate increases essentially linearly with power level. Considering the planned fuel management strategy, the core average burnup at Plant Vogtle could approach 40,000 MWD/MTU. Increases in burnup above the 30,000 level increase the decay heat rate only slightly. For Plant Vogtle, the decrease in decay heat rate due to a lower power level is significantly larger than the small increase due to increased burnup. Thus, there is reasonable margin between the WCAP-11916 results and any expected mode of operation at Plant Vogtle.

The decay heat source model used in WCAP-11916 and shown in Figure 3.2.4-1 of that report is based on Westinghouse methodology and is not available to us. In our evaluation, we utilized the NRC Branch Technical Position ASB 9-2 Rev. 2, July 1981 decay heat source model. We have shown that the two models give very close results; however, neither bounds the other at all times after reactor shutdown. The differences between the two models is small compared to the margin between the assumptions in WCAP-11916 and Plant Vogtle conditions.

Attached Figure 1 shows a comparison between the WCAP-11916 and the BTP ASB 9-2 decay heat models. Figure 2 gives a comparison between the WCAP-11916 decay heat model and three possible Plant Vogtle modes of operation: (1) Current power level with 30,000 MWD/MTU burnup, (2) Current power level with 40,000 MWD/MTU burnup, and (3) Uprated power level with 40,000 MWD/MTU burnup.

Based on the results of our evaluation, we conclude that the decay heat generated by both units of Plant Vogtle will always be bounded by the results of WCAP-11916.

If you have any questions, please contact me at extension 5079.

Approved by:

Warren M. Andrews

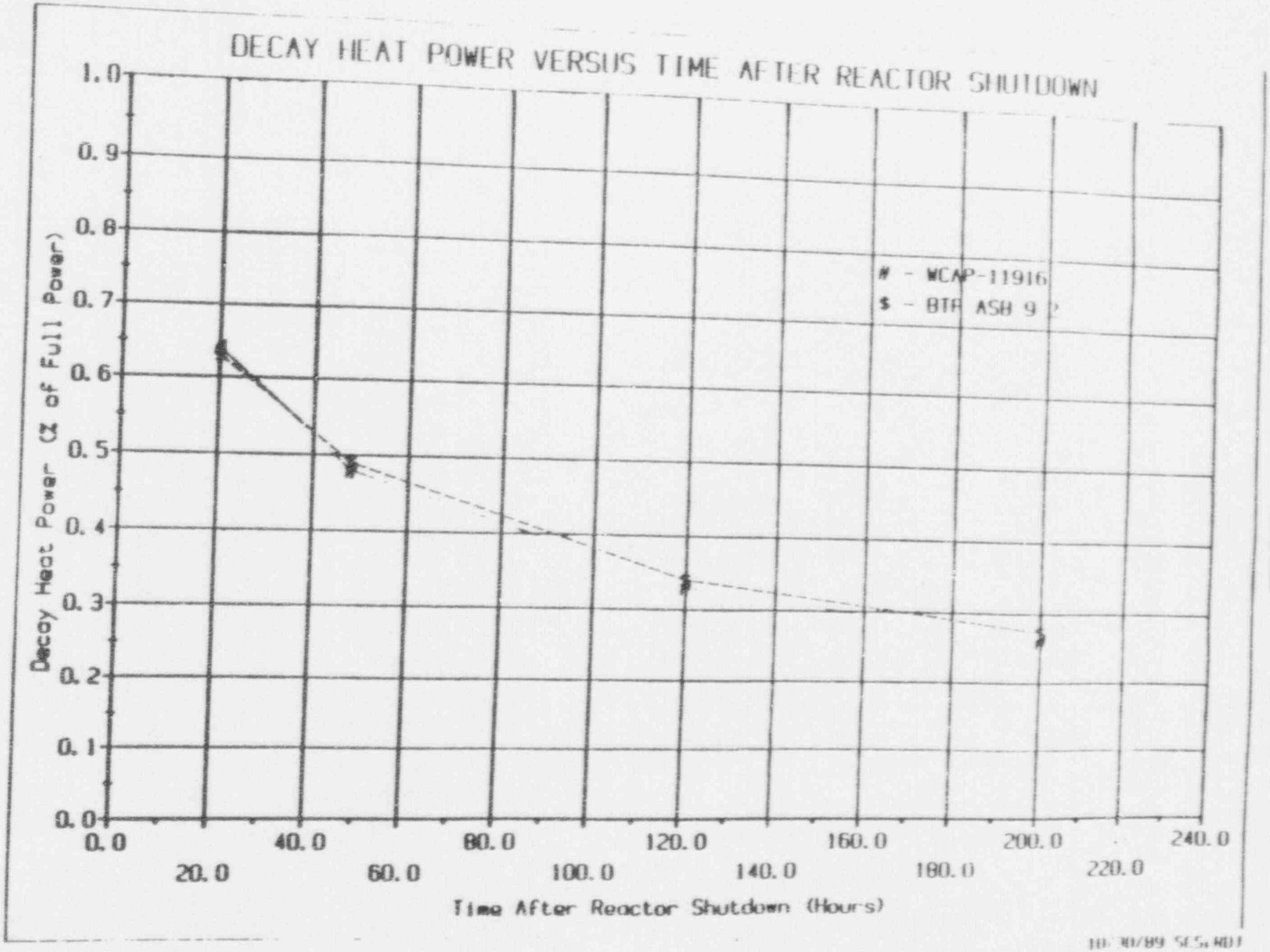
Warren M. Andrews
Manager, PWR Core Analysis

RDJ/gps

Attachments

cc: L. B. Long
B. E. Hunt
W. M. Andrews (w/att)
B. C. Armstrong (w/att)
D. R. Dotson (w/att)
C. R. Myer
R. E. Patrick

000798



DECAY HEAT POWER VERSUS TIME AFTER REACTOR SHUTDOWN
Decay Heat Power (% of Full Power)
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
- WCAP-11916
$ - BTP ASB 9 2
0.0
20.0
40.0
60.0
80.0
100.0
120.0
140.0
160.0
180.0
200.0
220.0
240.0
Time After Reactor Shutdown (Hours)
10/30/89 SCS.RDT

FIGURE 1

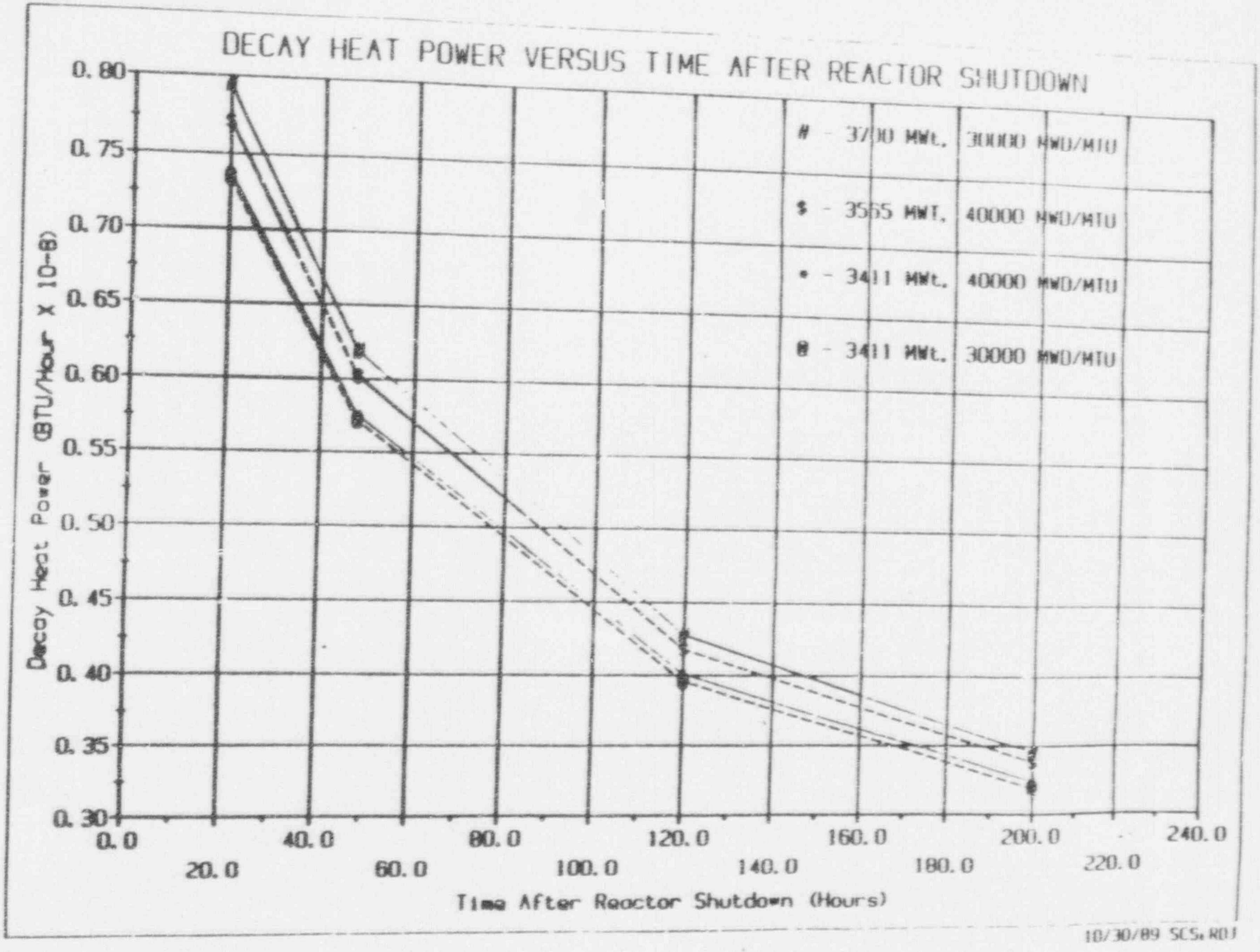

DECAY HEAT POWER VERSUS TIME AFTER REACTOR SHUTDOWN
- 3700 MWt, 30000 MWD/MTU
$ - 3565 MWT, 40000 MWD/MTU
* - 3411 MWt, 40000 MWD/MTU
@ - 3411 MWt, 30000 MWD/MTU
Decay Heat Power (BTU/Hour X 10-8)
0.80
0.75
0.70
0.65
0.60
0.55
0.50
0.45
0.40
0.35
0.30
0.0
20.0
40.0
60.0
80.0
100.0
120.0
140.0
160.0
180.0
200.0
220.0
240.0
Time After Reactor Shutdown (Hours)
10/30/89 SCS,RDJ

FIGURE 2

MAAP AS A POSSIBLE TOOL FOR MID-LOOP OPERATION ANALYSIS

Purpose

The purpose of this paper is to provide information for evaluating the capabilities of the Modular Accident Analysis Program (MAAP) for analyzing the PWR mid-loop operation condition.

History of MAAP

The MAAP code was originally developed by the Industry Degraded Core Rule-making program (IDCOR) and is now maintained by EPRI. Given an accident or a transient, MAAP simulates the plant response specifically accounting for system responses including operator interventions. The simulation continues either until a permanently coolable state is achieved or until the containment has failed and depressurized. Models are included for all the important phenomena that might occur during accident sequences leading to degraded core conditions. The code is highly modularized so that it can incorporate alternate physical models and can be adapted to different plant configurations such as power operation or shutdown conditions.

The MAAP code was obtained in 1987 when it was made available to utilities participating in the IDCOR program. Subsequently, SONOPCO Project (Technical Services) converted the MAAP code to run on a 386 personal computer. Technical Services personnel have received formal training on the use of MAAP and actively participates in an EPRI sponsored MAAP Users Group.

Structure of MAAP

Two sets of inputs are required by MAAP. One set of approximately one thousand inputs is the parameter file which in general specifies the following:

- Plant geometry (primary, secondary, containment, auxiliary building).
- Operating conditions (pressures, temperatures, water levels).
- System performance (including design specifications).
- Modeling parameters (shape factors, emissivities, particle sizes).
- MAAP execution control (time steps, print file identification).

The second set of inputs is the control card file (input deck) which includes the following:

- Accident sequence to be analyzed.

- Temporary changes to parameters.

- Manual operation or specific automatic controls.

The intervention conditions which MAAP uses to determine the timing of manual operations or automatic controls include various events or parameters such as the opening of safety valves, actuation of systems, pressures, temperatures, and levels. With the satisfaction of such predetermined conditions, MAAP may be instructed to take actions such as actuating specified components or systems.

For its output, MAAP prints a log of control inputs (directions from the input deck), a chronology of accident initiating events and imposed operator interventions, plus any MAAP system messages. Additionally, a tabular output file consisting of selected variables in all system compartments is written at the user-specified time interval. When the run terminates, a scenario summary of significant events is printed in the output.

Printed output of adequate detail can become excessive during a lengthy accident sequence, hence emphasis is placed on graphical output. Graphical output allows one to quickly interpret results, analyze trends, and capture fine detail missed by printed output. Technical Services uses the GRAPHER plotting software package to graphically display MAAP output data.

Benchmarking and Acceptance of MAAP

At present the primary application of MAAP is for use in addressing the severe accident issue as a part of the Individual Plant Examination (IPE). For the IPE work, MAAP will be used to determine success criteria (both core damage and containment performance) and to calculate source-term releases. It appears that most utilities plan to use MAAP for their IPE work if plant specific analysis is required. Although the NRC has not formally approved MAAP, it has not objected to the use of MAAP in the IPE effort.

Various benchmarking projects to validate the MAAP thermal-hydraulic models against actual plant data have been completed. Examples of favorable MAAP benchmarking include the modeling of the TMI accident and the Davis-Besse loss of feedwater transient. In addition, favorable benchmarking has been performed against RELAP (Seabrook by EG&G and Browns Ferry by TVA) and against MARCH 3 (PWR and BWR by the Nordic Nuclear Safety Program).

Mid-Loop Application of MAAP

After the publication of Generic Letter 88-17, "Loss of Decay Heat Removal," an interest was expressed by some utilities concerning modifications to MAAP that will allow the mid-loop accident to be modeled. Pacific Gas and Electric was the first utility to express an interest. However, General Public Utilities (GPU) on its own accord funded these modifications to MAAP. These modifications will allow MAAP to analyze the mid-loop accident to fuel uncovery. The MAAP Users Group has now authorized funding to modify MAAP to enable the analysis to continue past fuel uncovery. Although GPU has used the modified code for analyzing mid-loop accidents, these capabilities are not scheduled to be incorporated into the archived version of MAAP until June 1990.

The major features of MAAP that will allow modeling of mid-loop accidents include:

- Arbitrary initial conditions in the primary system.
    - o Initial water level or initial water mass.
    - o Air in the primary system.
    - o Input for a time since scram to calculate decay heat or cc e power as a function of time.
- Any initial conditions in the steam generator.
    - o Arbitrary water level.
    - o Air in the steam generator.
- User input for RHR inflow and outflow.
- Use of RHR heat exchanger.

MAAP will allow the user to determine the following:

- The primary system pressurization curve.
- Confirmation that various available injection paths and injection flows can control the accident.
- Estimation of the times available for action.
- Prediction of the system response that an operator would see.

Effort Involved in Using MAAP for Mid-Loop Analysis

Although a plant specific parameter file does not exist for Plant Vogtle at this time, it is anticipated that one will be created for the Vogtle IPE by the middle of 1991 with an effort of approximately 6 man-months. Many of these plant parameters will be obtained from design drawings and the FSAR.

A number of postulated loss of decay heat removal scenarios during shutdown, such as the following three scenarios for Seabrook that were analyzed manually can be evaluated by MAAP:

- The reactor is vented and remains at atmospheric pressure and the steam generators are dry, and the RHR cooling is lost.

- The reactor coolant system is not vented, the steam generators are dry, the vessel is filled with water, and the RHR cooling is lost.

- Conditions are the same as the previous scenario, except that the water is initially in the secondary side of some steam generators.

These scenarios could be expanded based on parameters such as the number of hours from scram and the initial water level in the vessel.

In the case of Vogtle, if the particular accident sequences are defined, Technical Services can create input decks to model these sequences. Depending upon the complexity of the sequence, an input deck could take approximately 4 hours to create. Although the Technical Services has run MAAP on the main frame computer, using the PC version of MAAP eliminates that expense. It is estimated that running a mid-loop scenario on the PC-based MAAP will require between 1 to 2 hours of computer time. As stated previously, the most effective analysis can be achieved by observing the plotted results of MAAP calculated parameters.

Conclusion

This discussion of MAAP as a possible tool for mid-loop operation analysis is based primarily on two presentations by other utilities at MAAP User Group meetings. MAAP with the modifications scheduled for mid-1990 appears to have sufficient capabilities to be considered as a useful tool for mid-loop operation analysis.

ATTACHMENT 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON D. C. 20555

October 17, 1988

TO ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR PRESSURIZED WATER REACTORS (PWRs)

SUBJECT: LOSS OF DECAY HEAT REMOVAL (GENERIC LETTER NO. 88-17) 10 CFR 50.54(f)

Loss of decay heat removal (DHR) during nonpower operation and the consequences of such a loss have been of increasing concern for years. Numerous industry and NRC publications have addressed the subject. The Diablo Canyon event of April 10, 1987, and ensuing work by both the staff and industry organizations have provided additional insight. Yet the problems continue, as illustrated by (1) the inadequacies demonstrated by many licensees in their response to Generic Letter (GL) 87-12; (2) the event at Waterford on May 12, 1988; (3) the event at Sequoyah on May 23, 1988; (4) the DHR perturbations due to inadequate level at San Onofre on July 7, 1988; and (5) the apparent lack of a complete industry understanding of the potential seriousness of such events.

The report of the Diablo Canyon event, NUREG-1269, stated that operating a plant with a reduced reactor coolant system (RCS) inventory was a particularly sensitive condition and identified many generic weaknesses in DHR. GL 87-12, which requested information from all PWR licensees, provided additional insight, and NUREG-1269 was transmitted with the generic letter to ensure that licensees had the latest information. Despite this, many of the responders to GL 87-12 demonstrated that they did not understand the identified problems.

Deficiencies exist in procedures, hardware, and training in the areas of (1) prevention of accident initiation, (2) mitigation of accidents before they potentially progress to core damage, and (3) control of radioactive material if a core damage accident should occur. Although deficiencies exist in all PWRs, certain design features make initiation and the time available for mitigation in the Westinghouse and Combustion Engineering designs of more concern than in the nuclear steam supply systems (NSSSs) designed by Babcock and Wilcox. Nevertheless, we believe expeditious actions are necessary at all PWRs to rectify these deficiencies. These should be paralleled by programmed enhancements which supplement, add to, or replace the expeditious actions to accomplish a more comprehensive improvement. Recommendations covering these items are summarized in the attachment, and additional information and guidance are provided in the three enclosures.

8810180350

Pursuant to 10 CFR 50.54(f), we request your response regarding your plans with respect to each of the recommendations as related to operation following placement of the NSSS on shutdown cooling, or following the attainment of NSSS conditions under which shutdown cooling would normally be initiated. Your response is to include the following:

1) A description of the actions you have taken to implement each of the eight recommended expeditious actions identified in the attachment. Your reply shall be submitted to us within 60 days of receipt of this letter.

2) A description of enhancements, specific plans, and a schedule for implementation for each of the six programmed enhancement recommendations identified in the attachment. Your reply shall be provided to us within 90 days of receipt of this letter.

Individual deviations from the recommendations will be considered on a case by case basis provided compensatory measures are provided which will achieve a comparable level of protection.

No further responses are required to GL 87-12 and licensees or construction permit holders need not provide any supplemental information in a response to GL 87-12 to which they previously committed.

We will accept documents such as technical reports, action plans, and schedules prepared by industry groups when accompanied by commitments from participating licensees in lieu of individual documents from those licensees. Alternatively, such industry group documents may be incorporated by reference in licensee documentation. We encourage your participation in cooperative efforts to effectively resolve these issues.

Your written response shall be submitted under oath or affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended. Your written response is needed to determine whether actions to modify, suspend, or revoke your license are necessary. An analysis as required by 10 CFR 50.109 has been performed regarding this request.

The original copy of your written response shall be transmitted to the U. S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555 for reproduction and distribution.

This request is covered by Office of Management and Budget Clearance Number 3150-0011 which expires December 31, 1989. The estimated average burden hours is 200 person-hours per licensee response, including assessment of the new requirements, searching data sources, gathering and analyzing the data, and preparing the required reports. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Room 3208, New Executive Office Building, Washington, D.C. 20503, and to the U. S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Administration and Resources Management, Washington, D.C. 20555.

If you have technical questions regarding this matter please contact Wayne Hodges at 301-492-0895. Other questions may be directed to the NRR Project Manager assigned to this issue, Charles M. Trammell (301-492-3121) or to the Project Manager assigned to your plant.

Dennis M. Crutchfield

Dennis M. Crutchfield
Acting Associate Director for Projects
Office of Nuclear Reactor Regulation

Attachment:
Recommended Actions

Enclosures:
1. Overview and Background Information Pertinent to Generic Letter 88-17
2. Guidance for Meeting Generic Letter 88-17
3. Abbreviations and Definitions

LIST OF RECENTLY ISSUED GENERIC LETTERS

Generic Letter No.	Subject	Date of Issuance	Issued To
88-16	REMOVAL OF CYCLE-SPECIFIC PARAMETER LIMITS FROM TECHNICAL SPECIFICATIONS	10/04/88	ALL POWER REACTOR LICENSEES AND APPLICANTS
88-15	ELECTRIC POWER SYSTEMS - INADEQUATE CONTROL OVER DESIGN PROCESSES	09/12/88	ALL POWER REACTOR LICENSEES AND APPLICANTS
88-14	INSTRUMENT AIR SUPPLY SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT	08/08/88	ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER REACTORS
88-13	OPERATOR LICENSING EXAMINATIONS	08/08/88	ALL POWER REACTOR LICENSEES AND APPLICANTS FOR AN OPERATING LICENSE.
88-12	REMOVAL OF FIRE PROTECTION REQUIREMENTS FROM TECHNICAL SPECIFICATIONS	08/02/88	ALL POWER REACTOR LICENSEES AND APPLICANTS
88-11	NRC POSITION ON RADIATION EMBRITTLEMENT OF REACTOR VESSEL MATERIALS AND ITS IMPACT ON PLANT OPERATIONS	07/12/88	ALL LICENSEES OF OPERATING REACTORS AND HOLDERS OF CONSTRUCTION PERMITS
88-10	PURCHASE OF GSA APPROVED SECURITY CONTAINERS	07/01/88	ALL POWER REACTOR LICENSEES AND HOLDERS OF PART 95 APPROVALS
88-09	PILOT TESTING OF FUNDAMENTALS EXAMINATION	05/17/88	ALL LICENSEES OF ALL BOILING WATER REACTORS AND APPLICANTS FOR A BOILING WATER REACTOR OPERATOR'S LICENSE UNDER 10 CFR PART 55
88-08	MAIL SENT OR DELIVERED TO THE OFFICE OF NUCLEAR REACTOR REGULATION	05/03/88	ALL LICENSEES FOR POW AND NON-POWER REACTOR AND HOLDERS OF CONSTRUCTION PERMITS FOR NUCLEAR POWER REACTORS

ATTACHMENT TO GENERIC LETTER

RECOMMENDED ACTIONS

Expeditious actions and programmed enhancements are recommended concerning operation of the NSSS during shutdown cooling or during conditions where such cooling would normally be provided. The recommendations apply whenever there is irradiated fuel in the reactor vessel (RV). These recommendations are summarized below and discussed further in enclosure 2:

<u>Expeditious actions</u>:

The following expeditious actions should be implemented prior to operating in a reduced inventory condition*:

(1) Discuss the Diablo Canyon event, related events, lessons learned, and implications with appropriate plant personnel. Provide training shortly before entering a reduced inventory condition.

(2) Implement procedures and administration controls that reasonably assure that containment closure** will be achieved prior to the time at which a core uncovery could result from a loss of DHR coupled with an inability to initiate alternate cooling or addition of water to the RCS inventory. Containment closure procedures should include consideration of potential steam and radioactive material release from the RCS should closure activities extend into the time boiling takes place within the RCS. These procedures and administrative controls should be active and in use:

(a) prior to entering a reduced RCS inventory condition for NSSSs supplied by Combustion Engineering or Westinghouse, and

(b) prior to entering an RCS condition wherein the water level is lower than four inches below the top of the flow area of the hot legs at the junction of the hot legs to the RV for NSSSs supplied by Babcock and Wilcox,

and should apply whenever operating in those conditions. If such procedures and administrative controls are not operational, then either do not enter the applicable condition or maintain a closed containment.

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* A reduced inventory condition exists whenever RV water level is lower than three feet below the RV flange.

** Containment closure is defined as a containment condition where at least one integral barrier to the release of radioactive material is provided. Further discussion and qualifications which the integral barrier must meet are provided in enclosure 2 and in the definitions provided in enclosure 3.

(3) Provide at least two independent, continuous temperature indications that are representative of the core exit conditions whenever the RCS is in a mid-loop condition* and the reactor vessel head is located on top of the reactor vessel. Temperature indications should be periodically checked and recorded by an operator or automatically and continuously monitored and alarmed. Temperature monitoring should be performed either:

(a) by an operator in the control room (CR), or

(b) from a location outside of the containment building with provision for providing immediate temperature values to an operator in the CR if significant changes occur. Observations should be recorded at an interval no greater than 15 minutes during normal conditions.**

(4) Provide at least two independent, continuous RCS water level indications whenever the RCS is in a reduced inventory condition. Water level indications should be periodically checked and recorded by an operator or automatically and continuously monitored and alarmed. Water level monitoring should be capable of being performed either:

(a) by an operator in the CR, or

(b) from a location other than the CR with provision for providing immediate water level values to an operator in the CR if significant changes occur. Observations should be recorded at an interval no greater than 15 minutes during normal conditions.**

(5) Implement procedures and administrative controls that generally avoid operations that deliberately or knowingly lead to perturbations to the RCS and/or to systems that are necessary to maintain the RCS in a stable and controlled condition while the RCS is in a reduced inventory condition.

If operations that could perturb the RCS or systems supporting the RCS must be conducted while in a reduced inventory condition, then additional measures should be taken to assure that the RCS will remain in a stable and controlled condition. Such additional measures include both prevention of a loss of DHR and enhanced monitoring requirements to ensure timely response to a loss of DHR should such a loss occur.

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* A mid-loop condition exists whenever RCS water level is below the top of the flow area of the hot legs at the junction with the RV.

** Guidance should be developed and provided to operators that covers evacuation of the monitoring post. The guidance should properly balance reactor and personnel safety.

(6) Provide at least two available* or operable means of adding inventory to the RCS that are in addition to pumps that are a part of the normal DHR systems. These should include at least one high pressure injection pump. The water addition rate capable of being provided by each of the means should be at least sufficient to keep the core covered. Procedures for use of these systems during loss of DHR events should be provided. The path of water addition must be specified to assure the flow does not bypass the reactor vessel before exiting any opening in the RCS.

(7) (applicable to Westinghouse and Combustion Engineering nuclear steam supply system (NSSS) designs) Implement procedures and administrative controls that reasonably assure that all hot legs are not blocked simultaneously by nozzle dams unless a vent path is provided that is large enough to prevent pressurization of the upper plenum of the RV. See references 1 and 2.

(8) (applicable to NSSSs with loop stop valves) Implement procedures and administrative controls that reasonably assure that all hot legs are not blocked simultaneously by closed stop valves unless a vent path is provided that is large enough to prevent pressurization of the RV upper plenum or unless the RCS configuration prevents RV water loss if RV pressurization should occur. Closing cold legs by nozzle dams does not meet this condition.

Programmed enhancements:

Programmed enhancements should be developed in parallel with the expeditious actions and they may replace, supplement, or add to the expeditious actions. For example, programmed enhancements may be used to change expeditious actions as a result of better understanding or improved procedures. This may lessen the initial impact of expeditious actions such as the speed with which containment closure must be achieved and may include consideration of such factors as the decay heat rate. Additional guidance is provided in enclosure 2. For example the first paragraph of section 2.2.2 and the first paragraph of section 3.3.2 illustrate the flexibility we have in mind as long as safety is adequately addressed. We intend that programmed enhancements be incorporated into plant operations as they are developed when this results in significant safety improvement or enhancement of plant operations with no decrease in safety. Procedural and hardware modifications may be implemented without prior staff approval where the criteria of 10 CFR 50.59 are met, although it is our intent to review and/or audit such changes. Programmed enhancements should be implemented as soon as is practical, but no later than the following schedule:

*Available means ready for use quickly enough to meet the intended functional need.

(1) Programmed enhancements consisting of hardware installation and/or modification, and programmed enhancements that depend upon hardware installation and/or modification, should be implemented:

(a) by the end of the first refueling outage that is initiated 18 months or later following receipt of this letter, or

(b) by the end of the second refueling outage following receipt of this letter,

whichever occurs first. If a shutdown for refueling has been initiated as of the date of receipt of this letter, that is to be counted as the first refueling outage.

(2) Programmed enhancements that do not depend upon hardware changes should be implemented within 18 months of receipt of this letter.

We recommend you implement the following six programmed enhancements:

(1) Instrumentation

Provide reliable indication of parameters that describe the state of the RCS and the performance of systems normally used to cool the RCS for both normal and accident conditions. At a minimum, provide the following in the CR:

(a) two independent RCS level indications

(b) at least two independent temperature measurements representative of the core exit whenever the RV head is located on top of the RV (We suggest that tempurature indications be provided at all times.)

(c) the capability of continuously monitoring DHR system performance whenever a DHR system is being used for cooling the RCS

(d) visible and audible indications of abnormal conditions in temperature, level, and DHR system performance

(2) Procedures

Develop and implement procedures that cover reduced inventory operation and that provide an adequate basis for entry into a reduced inventory condition. These include:

(a) procedures that cover normal operation of the NSSS, the containment, and supporting systems under conditions for which cooling would normally be provided by DHR systems.

(b) procedures that cover emergency, abnormal, off-normal, or the equivalent operation of the NSSS, the containment, and supporting systems if an off-normal condition occurs while operating under conditions for which cooling would normally be provided by DHR systems.

(c) administrative controls that support and supplement the procedures in items (a), (b), and all other actions identified in this communication, as appropriate.

(3) Equipment

(a) Assure that adequate operating, operable, and/or available equipment of high reliability* is provided for cooling the RCS and for avoiding a loss of RCS cooling.

(b) Maintain sufficient existing equipment in an operable or available status so as to mitigate loss of DHR or loss of RCS inventory should they occur. This should include at least one high pressure injection pump and one other system. The water addition rate capable of being provided by each equipment item should be at least sufficient to keep the core covered.

(c) Provide adequate equipment for personnel communications that involve activities related to the RCS or systems necessary to maintain the RCS in a stable and controlled condition.

(4) Analyses

Conduct analyses to supplement existing information and develop a basis for procedures, instrumentation installation and response, and equipment/NSSS interactions and response. The analyses should encompass thermodynamic and physical (configuration) states to which the hardware can be subjected and should provide sufficient depth that the basis is developed. Emphasis should be placed upon obtaining a complete understanding of NSSS behavior under nonpower operation.

(5) Technical Specifications

Technical specifications (TSs) that restrict or limit the safety benefit of the actions identified in this letter should be identified and appropriate changes should be submitted.

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*Reliable equipment is equipment that can be reasonably expected to perform the intended function. See Enclosure 2 for additional information.

(6) RCS perturbations

Item (5) of the expeditious actions should be reexamined and operations refined as necessary to reasonably minimize the likelihood of loss of DHR.

Additional information and guidance are given in enclosure 2.

REFERENCES

(1) C. E. Rossi, "Possible Sudden Loss of RCS Inventory during Low Coolant Level Operation," NRC Information Notice 88-36, June 8, 1988.

(2) R. A. Newton, "Westinghouse Owners Group Early Notification of Mid-Loop Operation Concerns," Letter from Chairman of Westinghouse Owners Group to Westinghouse Owners Group Primary Representatives (1L, 1A), OG-88-21, May 27, 1988.

ATTACHMENT 4

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON D C 20555

January 27, 1989

Docket Nos.: 50-424
50-425

Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
Georgia Power Company
P.O. Box 1295
Birmingham, Alabama 35201

Received

Dear Mr. Hairston:

SUBJECT: COMMENTS ON THE GEORGIA POWER COMPANY RESPONSE TO GENERIC LETTER 88-17 FOR THE VOGTLE PLANT, UNITS 1 AND 2 FOR EXPEDITIOUS ACTIONS FOR LOSS OF DECAY HEAT REMOVAL (TAC NOS. 69789 AND 69790)

The NRC staff has reviewed your response to Generic Letter 88-17. We find that it generally meets the intentions of the generic letter with respect to expeditious actions and is adequate for plant operation.

The most significant contributor to risk reduction of the eight generic letter recommendations is the capability to close containment. Your response appears to be incomplete in the following respects:

1. Tracking of containment penetrations references only those that have been opened by "manual means."

2. You specifically address closure of the equipment hatch via Operations Procedure 12006-C which ensures "that the containment equipment hatch can be closed." Abnormal Operating Procedure 18019-C "will instruct the operators to initiate containment closure." We find no reference to actual completion of containment closure within allowable times, particularly with respect to penetrations other than the equipment hatch.

3. You identify that "all available containment cooling fans be started to help mitigate the effects of a loss of RHR on the containment environment." You do not identify what reasonable assurance is available that fans will be available nor do you address whether you have investigated the feasibility of continued work within containment once boiling initiates within the reactor vessel and creates a steam environment within the containment.

VOGTILE

8902010362

In regards to the other expeditious items, the program identified in your response has the capability to adequately address the concerns expressed in the generic letter. However, your responses are brief and, therefore, do not allow us to fully understand your action taken in response to GL 88-17. You may wish to consider several observations in order to assure yourselves that the actions are adequately addressed:

1. You reference the commitments as implemented prior to the next planned entry. We assume your meaning is for any entry into a reduced inventory condition that is deliberate on the part of the operators. Hence, an entry for the purpose of repairing an unanticipated reactor coolant pump seal failure would be a planned entry. An entry due to a loss of coolant accident would be unplanned. Any other meaning will not meet the intent of the generic letter.

2. You also reserve the right to make changes "in the future if appropriate." The intent of the generic letter is to allow changes under the guidance of the programmed enhancement recommendations and subject to your 50.59 review, as applicable.

3. The lesson plan description did not identify the need for instrumentation other than level indication. Temperature and the ability to monitor RHR behavior are also important.

4. The lesson plan description did not identify such vortex detail as symptoms and suitable operator response to prevent loss of RHR.

5. The lesson plan description is stated to provide "an adequate awareness on the part of personnel involved in mid-loop operations." Historical experience shows many RHR losses caused by apparently trained personnel - often by maintenance and test personnel. Your program should be designed to avoid such difficulties.

6. You indicate removal of a pressurizer manway, steam generator manway, or three pressurizer code safety valves as means to provide RCS venting. We note that relatively large hot side openings in the RCS, such as a pressurizer manway, can still lead to a pressure of several psi due to the large steam flow and the combination of flow restrictions in the surge line - lower pressurizer hardware - manway opening. Calculations should be performed to verify the effectiveness of the opening.

There is no need to respond to the above at this time.

As you are aware, the expeditious actions you have briefly described are an interim measure to achieve an immediate reduction in risk associated with reduced inventory operation, and these will be supplemented and in some cases replaced by programmed enhancements. While your response is adequate, we intend to audit both your expeditious actions and your programmed enhancement program. The areas where we do not fully understand your responses as indicated above may be covered in the audit of expeditious actions.

Sincerely,

Jon B. Hopkins

Jon B. Hopkins, Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

cc: See next page

ATTACHMENT 5

ELV- 00186
X7GJ17-V110
0942D

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

PLANT VOGTLE - UNITS 1, and 2
NRC DOCKET 50-424, 50-425
OPERATING LICENSE NPF-68, CONSTRUCTION PERMIT CPPR-109
RESPONSE TO GENERIC LETTER 88-17

Gentlemen:

In accordance with 10 CFR 50.54(f), Georgia Power Company hereby submits the enclosed response to the recommended programmed enhancements of Generic Letter 88-17 related to loss of residual heat removal while operating in a reduced inventory condition. This response applies to both Units 1 and 2, even though unit specific details may refer to Unit 1. Georgia Power Company responded to the recommended expeditious actions of Generic Letter 88-17 by letter dated December 29, 1988

Georgia Power Company expects to implement all hardware changes resulting from the programmed enhancements prior to resuming critical plant operations following the second Unit 1 and first Unit 2 refueling outages. Enhancements that do not involve hardware changes are scheduled to be implemented by May 3, 1990.

Evaluation of hardware changes for level instrumentation and residual heat removal system performance indication has not been completed. In that the evaluation is not complete, Georgia Power Company cannot be more specific than the enclosed response. Georgia Power Company will submit a description of these hardware changes within approximately two months following completion of the evaluations, which is currently projected for October 1, 1989.

The enclosed responses are based upon current or proposed practices and may be changed in the future, if appropriate. Georgia Power Company will ensure that any future changes will maintain the intent of Generic Letter 88-17. Information related to this issue will be available onsite for NRC review.

If there are any questions concerning this letter, please advise.

Mr. W. G. Hairston, III states that he is a Senior Vice President of Georgia Power Company and is authorized to execute this oath on behalf of Georgia Power Company and that, to the best of his knowledge and belief, the facts set forth in this letter and enclosures are true.

GEORGIA POWER COMPANY

By: ______________________
W. G. Hairston, III

Sworn to and subscribed before me this ____ day of January, 1989.

____
Notary Public

c: Georgia Power Company
Mr. P. D. Rice
Mr. C. K. McCoy
Mr. G. Bockhold, Jr.
GO-NORMS

U. S. Nuclear Regulatory Commission

Mr. M. L. Ernst, Acting Regional Administrator
Mr. J. B. Hopkins, Licensing Project Manager, NRR (2 copies)
Mr. J. F. Rogge, Senior Resident Inspector-Operations, Vogtle

ENCLOSURE

GEORGIA POWER COMPANY RESPONSE TO
NRC GENERIC LETTER 88-17
PROGRAMMED ENHANCEMENTS

The following discussion of Georgia Power Company's (GPC) plans for addressing the programmed enhancements of Generic Letter 88-17 at Plant Vogtle (VEGP) is provided pursuant to 10 CFR 50.54(f):

1. NRC RECOMMENDATION

Provide reliable indication of parameters that describe the state of the reactor coolant system (RCS) and the performance of systems normally used to cool the RCS for both normal and accident conditions. At a minimum, provide the following in the control room:

(a) Two independent RCS level indications.

(b) At least two independent temperature measurements representative of the core exit whenever the reactor vessel (RV) head is located on top of the RV. (We suggest that temperature indications be provided at all times.)

(c) The capability of continuously monitoring residual heat removal (RHR) system performance whenever an RHR system is being used for cooling the RCS.

(d) Visible and audible indications of abnormal conditions in temperature, level, and RHR system performance.

GPC RESPONSE

(a) As stated in our December 29, 1988 submittal, RCS water level is monitored via temporary level instrumentation whenever the RCS is in a reduced inventory condition. Operations procedures include instructions to notify Instrumentation and Control personnel to install temporary level instruments prior to draining the RCS. Instrumentation and Control Procedure 23985-1, "RCS Temporary Water Level System", provides instructions for installation of two independent channels of level indication using temporary transmitters and existing level instrumentation in the control room. Level is measured directly from the hot leg between the RVLIS upper range lower tap and the pressurizer to minimize thermodynamic and pressure errors. One channel provides wide range level indication from approximately one foot below mid-loop to the vessel flange. The other channel provides narrow range level indication from approximately one foot below mid-loop to the top of the hot leg. Level is continuously monitored and alarmed in the control room. A low level alarm is set at three inches above the center of the hot leg.

GPC is presently evaluating a design change which will provide for permanent installation of the level transmitters. We expect to have this evaluation completed by October 1, 1989.

The design development will include a review of the instrumentation design and an error analysis. GPC will also perform a quality control and follow-up review of the installation and review maintenance and calibration practices.

(b) As stated in our December 29, 1988 submittal, Operations Procedures presently require at least two core exit thermocouples to be operable at all times during reduced inventory conditions with the RV head in place. These procedures will be revised to require either:

- Temperature will be monitored and recorded by an operator in the control room at intervals no greater than 15 minutes, or

- Temperature will be continuously monitored and alarmed via the Emergency Response Facility (ERF) computer in the control room.

These two core exit thermocouples will provide continuous, independent, and representative indication of the core temperature.

(c) An engineering study will be made to determine the specific parameters that will provide timely, reliable indication of the onset of degraded RHR pump performance. The study will include consideration of the recommendations of Generic Letter 88-17 such as indication of pump motor current, noise monitoring, suction pressure indication, and a possible correlation of parameters. We expect to complete this study by October 1, 1989. The results of this study will be implemented according to the schedule discussed in the cover letter to this transmittal.

(d) As discussed above, RCS level is continuously monitored and alarmed in the control room during operation in a reduced inventory condition. Temperature will either be checked and recorded by an operator in the control room at intervals no greater than 15 minutes, or continuously monitored and alarmed via the ERF computer in the control room. The engineering study discussed in item (c) above, will include consideration of visible and audible indication of RHR system performance.

2. NRC RECOMMENDATION

Develop and implement procedures that cover reduced inventory operation and that provide an adequate basis for entry into a reduced inventory condition. These include:

(a) Procedures that cover normal operation of the NSSS, the containment, and supporting systems under conditions for which cooling would normally be provided by the RHR system.

(b) Procedures that cover emergency, abnormal, off-normal, or the equivalent operation of the NSSS, the containment, and supporting systems if an off-normal condition occurs while operating under conditions for which cooling would normally be provided by the RHR system.

(c) Administrative controls that support and supplement the procedures in items (a), (b), and all other actions identified in Generic Letter 88-17, as appropriate.

GPC RESPONSE

(a) As stated in our December 29, 1988 submittal, the controlling procedure for operation in a reduced inventory condition is Operations Procedure 12006-C, "Unit Cooldown to Cold Shutdown." This procedure contains precautions and limitations concerning operation in a reduced inventory condition and provides guidance for preparing the RCS for draining. This guidance address temperature and level instrumentation, RHR pump performance, and the use of a safety injection pump for inventory addition, if needed.

Procedure 13005-1, "Reactor Coolant System Draining", provides instructions for draining the RCS. This procedure also contains precautions concerning the effects of RCS level on RHR system operability and instructions which should minimize the impact of draining on level indication.

Procedure 13011-1 "Residual Heat Removal System", provides the necessary instructions for operation of the RHR system including operation in a reduced inventory condition. The precautions of this procedure address the effect of RHR system flow on pump suction during reduced inventory operation.

(b) In the event of a loss of RHR, Abnormal Operation Procedure 18019-C, "Loss of RHR", will provide the necessary guidance to ensure core cooling and direct the operators to initiate containment closure. Containment closure will be accomplished via Maintenance Procedure 27505-C, "Opening and Closing Containment Equipment Hatch" and administrative control in the form of an Information Limiting Condition for Operation (LCO), which will ensure that all penetrations opened by manual means are tracked.

(c) As stated in our December 29, 1988 submittal, the Shift Supervisor maintains cognitive control over the equipment hatch and all penetrations opened by manual means. Administrative controls will also ensure that the following is available for recognizing and mitigating a loss of RHR event:

- Instrumentation,
- Equipment for inventory addition,
- Adequate hot leg vent path, and
- Safe work environment to complete containment closure.

GPC believes that, with the revisions to procedures discussed in our December 29, 1988 submittal, VEGP procedures will reflect the best current practice with regard to operation in a reduced inventory condition. However, any further guidance that results from Westinghouse Owners' Group activity on this topic will be reviewed and incorporated into procedures as appropriate.

3. NRC RECOMMENDATION

(a) Assure that adequate operating, operable, and/or available equipment of high reliability is provided for cooling the RCS and for avoiding a loss of RCS cooling.

(b) Maintain sufficient existing equipment in an operable or available status so as to mitigate loss of RHR or loss of RCS inventory, should they occur. This should include at least one high pressure injection pump and one other system. The water addition rate capable of being provided by each equipment item should be at least sufficient to keep the core covered.

(c) Provide adequate equipment for personnel communications that involve activities related to the RCS or systems necessary to maintain the RCS in a stable and controlled condition.

GPC RESPONSE

(a) The RHR system at VEGP is part of the Emergency Core Cooling System (ECCS). This system is safety related and therefore highly reliable. Furthermore, the RHR autoclosure interlock function is defeated in Modes 5 and 6 which eliminates the associated potential for spurious closure of the RHR suction isolation valves.

(b) Inventory addition will be accomplished via a centrifugal charging pump and a safety injection pump. Both of these pumps are part of the ECCS and are therefore highly reliable. The flowrates available from these pumps will be more than sufficient to keep the core covered. Administrative controls will assure that flow paths are available for these pumps and that flow will not bypass the core. Furthermore, Procedure 18019-C provides for the use of the steam generators as an alternate means of cooling when appropriate.

(c) Adequate equipment for personnel communications during reduced inventory operation presently exists at VEGP and is required by procedure.

4. NRC RECOMMENDATION

Conduct analyses to supplement existing information and develop a basis for procedures, instrumentation installation and response, and equipment/NSSS interactions and response. The analyses should encompass thermodynamic and physical (configuration) states to which the hardware can be subjected and should provide sufficient depth that the basis is developed. Emphasis should be placed upon obtaining a complete understanding of NSSS behavior under non-power operation.

GPC RESPONSE

GPC, as a member of the Westinghouse Owners' Group, has reviewed WCAP-11916 and utilized the analysis and guidance provided therein as a basis for the hardware and procedural changes discussed in our December 29, 1988 submittal. Further analysis is being performed by Westinghouse to validate the abnormal operating procedure guidance. When this analysis is complete and the procedural guidance finalized, GPC will review the information for VEGP and make changes as appropriate. In addition, the design review discussed for RCS level instrumentation will account for effects that may introduce level inaccuracies. Furthermore, special pre-operational testing has been performed on Unit 2 which varied RCS level and RHR system flow to determine susceptibility to vortexing. Finally, a plant specific analysis will be made to support inventory addition via gravity flow from the refueling water storage tank to the RCS.

5. NRC RECOMMENDATION

Technical Specifications that restrict or limit the safety benefit of the actions identified in this letter should be identified and appropriate changes should be submitted.

GPC RESPONSE

GPC plans to pursue a change to the Technical Specifications which will allow the safety injection pumps to be available during operation in a reduced inventory condition without having to invoke 10 CRF 50.54X.

6. NRC RECOMMENDATION

Item (5) of the expeditious actions should be reexamined and operations refined as necessary to reasonably minimize the likelihood of loss of RHR.

GPC RESPONSE

As stated in our December 29, 1988 submittal, VEGP has procedures in place that require authorization from the Unit Shift Supervisor prior to performing any work. Operations procedures include precautions to scrutinize and limit work activities that have the potential for reducing RCS inventory while in a reduced inventory condition. These procedures will be revised to ensure that any work that may impact RHR capability while in a reduced inventory condition be closely scrutinized. Work will not be allowed to be performed unless adequate measures exist (such as enhanced monitoring of critical parameters and precautions and limitations) to prevent a loss of RHR.

GPC believes that the above measures in conjunction with the emphasis placed on mid-loop operations during licensed operator training and the other measures discussed in this letter and our December 29, 1988 letter are adequate to minimize RCS perturbations during reduced inventory operation.