The other thing that Mike talked about, the deep drain valve work, the reactor coolant pump work is ongoing.

I'm just going to walk through, I think for maybe the purposes of demonstrating, going through these pictures and I'll point some items out.

Okay, we talk a lot about this emergency sump. This is a pit right here. And under design basis accident, you're flowing water into the containment building. And it fills up from under vessel, and all of the water then, from this elevation right here, which is actually the 565 foot elevation of containment; it floods up about 18 inches above that. That's under design basis, the amount of water, about a half million gallons or so that go into containment.

This was covered with a screen, kind of a chicken wire affair, if you will, that was not very substantial and only forwarded us about 50 square feet of screenage. Why that's important is that this water as it fills up then comes through these two valves. They're what's called vortex breakers, cruciform breakers, that allow antivortexing of water that's going back into the cooling system for redistribution back into containment.

This area was covered over. That has been completely removed. This is a stainless steel backing plate. There are structural beams. In fact, I walked this down yesterday. Two of those beams that Mike is talking about have been installed. Quite a substantial configuration here.

This area, it will be called the top head. Now we're looking at a kind of 45 degree angle here, so this top hat area has about three hundred square feet area of screen that will allow at 18 inches above that elevation, that will allow water to flow into that area and be redistributed.

Now, on the far side of this sump is a cutout area. We've started that, that cutout now. It's about 18 inches wide, about 30 inches long, and that will allow some extension pipes, which are drilled pipes to go down under the vessel, and we'll see another conceptual design. But actually, when I was walking it down yesterday, one of the pipe sections had been mocked up with a piece of insulation, so the guys could actually figure out, will it fit in there properly. That will add another several hundred, about up to a total of 1200 square feet of screen.

So, you maybe can't get a lot of picture. These covers here, that's plastic. It's a foreign material exclusion cover, so we don't want to get any grit or debris in this pipe. So, they're covered over.

You see a chainfall here for lowering and raising equipment into that sump.

MR. SCHRAUDER: Randy, I walked it down this morning and they've got four beams done.

MR. FAST: Oh. So, we got two beams done since yesterday. Excellent. Thank you, Bob.

Okay. This is the decay heat valve pit. Now, it's very difficult to get the concept here, but in this recirculation mode, there are two valves here; Decay Heat 11 and Decay Heat 12. And they will redistribute water, so these have to be able to be open after a design basis event.

This pit or sump is 19 feet long, 7 feet deep and about 7 feet wide. So, the walls of this sump will be lined with stainless steel and sealed to allow proper environmental controls after a design basis accident. So, that's what Mike was briefing us on a little bit earlier.

This is the fan blades for containment air coolers. Now, containment air coolers are basically like an air conditioner for your house in that it redistributes air to ensure proper environmental controls. In a design basis accident, we recirculate air for making sure that the temperature and the pressure in containment is minimized. So, this is one of the fan blades.

I'm trying to give you a concept of how, they're about, I would say, 8 feet in diameter. So, these are pretty significant.

These, this is the structural platform for the cooling coils. You can see just, kind of see, you don't get the whole piece of it. This would be one, like a radiator from your car, so that's one cooling coil. There is one, two, three, four sides of the box, so a total of twelve.

Coming down and distributing service water, which is the cooling medium for the containment air coolers are the inlet and outlet piping. That's what we have redesigned and we'll be reinstalling this stainless steel improved to ensure proper flow distribution through the containment air coolers. This is at 585 foot elevation. This spans basically from the 585 down to the 565 foot elevation.

Next slide. This is just looking up into the fan. So, we're down at 565 foot and you're looking up into the fan. So, air is distributed from containment at 585 feet through the cooling coil, down through the fan, down into an outlet plenum and then back and ~~redescribed~~ redistributed back inside of the D rings where the steam generators are located.

Not a lot to see here, but we're using a sponge blast process to remove paint from equipment in containment. This happens to be core flood tank number one. It's tinted. We use a sponge blast media. It's pretty nonintrusive. It does remove paint. It preps the surface, and we have pictures of what it looks like when we're done.

There is the tank painted bright white and completely remediated. This is an engineered coating. Now, why do I use the term, engineered coating? It's because in reality this will sustain under design basis accident, so it's an approved long term, won't remove from jet steam impingement or any conditions that would exist post-accident.

MR. MYERS: Would it be fair to say from a coating standpoint, we understand our coatings better than at any plant you worked at now?

MR. FAST: We know a lot about paint. We've certainly, we've partnered with the industry best and brightest and I feel good about the condition that we're leaving the condition in.

Okay. With that, I'm going to turn it over to Jim Powers.

MS. LIPA: I did have a question for you, Randy.

MR. FAST: Yes.

MS. LIPA: Several meetings back, we talked about the coatings on the conduits. Has that issue been resolved?

MR. FAST: The coatings on the conduit is unqualified. And let me go into a little detail on that. When the plant was originally built, one of the things that was done, you have galvanized, which is a normal coatings process, on the conduit, but somehow we elected to go back and paint it. And, that paint is not qualified. So under design basis, some of that paint will be removed.

Some of what we're doing with the emergency sump screenage will allow for some of that paint, as it's removed, will be trapped by that screen. So, we'll have sufficient margin that right now, based on our engineering analysis, we can have some coatings, unqualified coatings, and still maintain margin for the sump.

So, the target areas we had was containment dome, the core flood tanks, service water piping, and we do have some other selected areas. We do have an initiative where our Operations staff is taking a leadership role in removing some of the coatings using other processes; not sponge blasting, but just to remove some of those unqualified coatings inside the D rings. But not all of it will be remediated.

MS. LIPA: Okay. I think that this is probably a good time for a break. I know you're all ready, Jim, but we'll take a ten minute break unless you had any questions.

MR. GROBE: I just wanted to make sure I was clear on this. So, it's your intention to not removed the unqualified coatings from the conduit based on the design margin sump?

MR. POWERS: Not entirely, Jack. That's correct. I'll talk a bit about the sump after the break, but it adds a good deal of margin and we're factoring in whatever unqualified coatings remain in containment will be factored into the design basis of the sump, and in the last meeting we discussed making sure the license basis reflects that as well.

MR. MYERS: Let me answer that question. I met with a coating engineer last week, and our intention, we're going to buy some, we're going to try to sponge blast the stuff. We're going to buy some stuff, I hate to say like you see on TV, where you put it on and it takes the paint off.

The operators are going to do that. We're going to get as much of that coating off that conduit as we can before we start up. That will give us excessive margin. From a design standpoint, it's not a problem, but it just doesn't do anything but gain margin, so we're going to remove as much of it as we can. Okay?

MR. DEAN: Let me ask, Jim,
are you going to get in a discussion of, you know, there has been operability concerns about the containment air coolers and the coatings; is that something you will have an opportunity to discuss?

MR. POWERS: Sure, I can give
you an update on that. We're not entirely finished with that, but I can give you an in-process update.

MR. MYERS: Now we have eight
minutes?

MS. LIPA: Okay, let's start
our ten minutes now. It's 3:23, be back at 3:33. Thank you.

(Off the record.)

MS. LIPA: Okay, go ahead.

MR. POWERS: Okay. There is
two things I would like to update us on this afternoon; one is the status of the System Health Assurance Building Block and the other is an update on the NRC public meetings we had at headquarters in Rockville on November 26th, both about the emergency containment sump and the undervessel incore nozzles.

The first issue I want to touch on is Containment Emergency Sump. You heard quite a bit on it today by Mike and Randy. This gives another perspective of the sump and where it's located in the containment, and what we're going to do to significantly expand our sump.

The normal sump, as shown up in the upper righthand corner of the picture, there is a sump access area. Up in that corner is where the existing sump pit is that Randy pointed out in the photo graph. That's where the construction is ongoing.

Now we're to go work from that sump and we're going to go down the stairwell. You can see there is a stairwell tunnel that leads down to under the reactor vessel, and you can see the bottom of the reactor vessel there on the left hand portion of this three-dimensional figure.

Down along that stairwell is where the incore nozzle guide tubes run. And they run down there. There is 52 of them; very small diameter steel tubes that run down through the tunnel, along the side of it and up into the bottom of the reactor vessel. And we'll see those in more detail just following this.

But there is room down there that we can use to expand our containment sump strainer screen. And you can see the lower strainer pointed out in the, in the picture here as it runs down the stairwell.

Right now, we have 50 squares feet of screen in the original design. That was removed. And we're moving towards expanding that up to 1200 square feet of a perforated plate strainer structure. And most of what you see here in terms of the strainer itself, all the piping and manifold boxing that's shown will be perforated, so it all contributes to straining out any sort of debris that may be generated and providing plenty of flow to the emergency core cooling system suction.

So, we're going to place it as shown here. We believe this is a model for the industry. And, that's what we presented to the participants at the NRC. The desired outcome of that meeting was to solicit any comments or questions from the Nuclear Regulatory Commission staff, the Technical Reviewer staff. And they were very curious about this development. We intend to resolve the generic safety issue 191, as it's referred to in the industry, relative to containment emergency sump functionality.

It's an issue that's the industry has been grappling with over several of the last years. It's been resolved at the BWR's and we resolved it pretty effectively over at the Perry Plant several years ago. And we brought many of the same people that participated in that resolution to bear on this resolution at Davis-Besse Plant.

So, we look at this as a model for the industry. And our intent is to provide a demonstration for some of our peer utilities to come and see how to effectively resolve this issue.

In the next slide, we show the reactor vessel bottom nozzles. On the left you can see a photograph of the bottom head of the vessel and where I talk about the incore guide tubes leading up into the bottom of the vessel. Here we can see them coming up into the bottom. There is a metallic insulation layer that's been removed, so that we can see them.

During normal plant operation, the reactor is enclosed in metallic ~~installation~~ insulation, as you can see on the righthand depiction here, that keeps the heat. The reactor vessel is 500 degrees in temperature when we are in full power operation. And to keep the concrete around it cool and minimize the heat loads in containment, it's all encapsulated.

We stripped off all that insulation as part of our discovery proceedings in containment to do a full inspection of the bottom head. We've conducted what we believe is the most thorough bare metal inspection of the bottom reactor head that's been done to-date in the industry. And we inspected thoroughly with a crawler remote robot, so we could look very closely and not expose our staff to undue radiation. And we went and we cleaned very thoroughly the head.

There you can see its post clean state. And once we go up to do our pressure test, pressure and temperature test, at full pressure and temperature for 7 days and come back down, we'll be able to go in there, and if there is any indication of leakage, it will show up by white Boron residuals.

And, our plan is to do that test. Go in and examine to see if there is any leakage. We don't believe that there is any, based on all the work that's been done to-date. But if there is, we have a repair concept that, that is ready to go; repair that's been done on pressurizer vessels very similar to these type of penetrations. So, that's in the wings and ready to go should we need it.

One of the other firsts that we're doing, as far as this project, first U.S. installation of what we call our Flus Monitoring System. This is a moisture monitoring system that was developed in Europe and used in reactor systems over there to monitor for any sort of leakage. It's picked up as a change of moisture content in the air.

And we'll install the small sampling tubes within the metallic insulation package. And you can see that, it's shown in the righthand side here in this figure. Small tubes laid out in insulation. They will be continuously sampling the air to determine if there is any change in moisture. If there is, we'll then take the actions that will be prescribed in the operating procedures for this monitoring system.

So, this is another first that we'll be installing. When we spoke to you last month at the public meeting, we weren't sure at that time whether we would be able to get this installed by the end of this outage. Now, based on the work we've done with Framatone, our supplier, our reactor supplier and the supplier of this monitoring system, we believe we can get this installed prior to the end of this outage. And, we're working towards that goal.

MR. GROBE: Jim, before you go to your next slide. I wanted to make sure I was speaking into the microphone, and for a moment I forgot my question. It will come back.

MR. POWERS: I'm sure it's a good one.

MR. GROBE: But everybody can hear that I forgot my question.

MR. POWERS: I'll move on to System Health, and I'm sure it will come to you.

MS. LIPA: I did have a question before you go on, Jim. When we had the meeting on November 26th, I think we talked at that meeting about some tape that was on some of these lower nozzles. What did you find about those?

MR. POWERS: What we found, there was a few more pieces of evidence we wanted to take to see if they could help us characterize the Boron stains that were found at the bottom of the vessel. There were a couple pieces of tape that were remaining, apparently from original construction completion. And the tape was enclosed in the portion of tubing that was hidden by the insulation panels. And those are typically not removed, those insulation panels. So, it really hadn't been found until we did this complete removal and thorough cleaning and inspection.

So, we took the tape samples off and sent them to the lab. We also took some scrapings of the paint that was on the side of the vessel, and sent that off to see if that would help us characterize the results of the lab analysis, the chemical analysis of the Boron samples we had taken.

And, in fact, they did the analysis. It didn't really help us. It didn't clarify anything further, Christine, in terms of knowing where the Boron, you know confidently stating where the Boron originated from.

We believe it came from above, from washdowns of the Boron that was on the head, and also from leakage through our temporary refueling cavity seal.

One of the reasons Lew talks about so emphatically enthusiastically about putting this cavity seal in, is that it's going to prevent leakage and prevent these types of questions from occurring. And many of the stains we saw on the side of the vessel were Boron deposits likely from that type of leakage source.

The cavity seal, for your information, will go up at the top of the sketch, where you see the concrete; there is a gap between the concrete and reactor vessel at the top level there. That's the flange where the head comes off the vessel during refueling. And, then you take the head of the vessel off, then you put a seal plate around that gap. That seals the cavity, the reactor annulus cavity. Then you can flood up with water in a refueling canal and pull your fuel out of the vessel and handle it for refueling.

So, that's an important function; and once we put in a permanent seal, then we'll have a high integrity water tight barrier there, and we don't expect to have any more leakage questions.

MR. GROBE: Jim, were there any chlorides concerns that arose from discovery of this tape?

MR. POWERS: No, there wasn't, none that was reported, Jack.

MR. GROBE: Interesting.

I remembered my question earlier. I think you've answered it to some extent, but you indicated a belief that the bottom head penetrations are not cracked and not leaking. Could you go into some detail on the basis for that belief?

MR. POWERS: Well, the basis really is that if you look at the flow trails, as we refer to them, that came down the side of the vessel, there was two different flow trails; one was a reddish colored, rust colored flow trail on the one side of the vessel and the other one was a white colored flow trail.

The reddish colored flow trail corresponded to a location where the deconers, technical deconers staff at the station had reported that when they were cleaning the head, that some of the, some of the deposit had washed down the side of the vessel, over the flange and down the side of the vessel before they put in their cavity seal as part of the initial stages of refueling when they were cleaning the bolts to undo the reactor head bolts.

And the other trail came down from what looks like on the other side of the vessel what would potentially either be from the reactor cavity seal leakage, and we also found as part of our inspections of this outage that there is a couple of pressure detection lines that are associated with the head and they're used to detect the integrity of O ring seals. And we found that those had been cracked at some time in the past.

So, when the, when the refueling canal is filled with water, they may have been drippings and some leakage as well. And so, we believe that there is evidence that these flow trails came from those sources.

Now, the chemical analysis that we did showed higher levels of lithium and Boron in some of the nozzle locations, which is interesting there is a higher concentration of Boron and lithium, but the interesting thing was that there is no constituents, activation product constituents from reactor coolant that you would expect to see if we had an actual leak from inside the vessel.

So, there was some contradictory information there. Although it was, it was interesting that some of these nozzles at higher levels of Boron, it didn’t show activation products that we would have expected had it been reactor coolant leakage.

And, when you look at the size of the samples that were able to be taken, how they were taken, you know, the amount of material that the chemists had to work with for their analysis and how it may have been, it may have been affected by, for example, the paint that was on the side of the vessel; that’s one of the reasons we sampled it; Scotch Bright pads that were used to remove, scrape off the sample, the very small amounts we were able to obtain, led to questions on whether, you know, the quality of the samples, the conclusiveness of the chemical analysis.

MR. GROBE: Have there been any observed bottom head nozzle cracking in other plants in the United States or in Europe?

MR. POWERS: No, not so far. The French plants have surveilled, I think it's 17 plants have been surveilled since 1993. And, although their bottom nozzles are a bit different than ours, they still have the similar type of pressure boundary weld associated with them. And they still have temperatures in the range of the temperatures that we have.

These nozzles have been believed for a long time to be less susceptible to cracking than many other nozzles in higher temperature portions of the Reactor Coolant System. The French have never seen any cracks. Domestic plants have also done some inspections in recent outages looking for any evidence of leakage from these nozzles and have reported none observed.

So, no, there is no evidence thus far of cracked nozzles.

MR. GROBE: One more question before we get away from the bottom head. Did you observe any apparent contaminants on penetrations that weren't part of the flow path that appeared to be coming down the side of the vessel?

MR. POWERS: I believe every

one of the nozzles that we sampled was, was engaged or involved in one of the flow paths. And we picked the samples, the nozzles, there were twelve of them, based on, largely on the appearance and, you know, tracking attention of an area that should be sampled to see if there was any conclusive evidence that would be available from a chemical sample.

And, Bob, was that the case?

MR. SCHRAUDER: Jack, I don't have a microphone, but there were some nozzles that had deposits on them that were not evidently in a flow path.

MR. GROBE: Okay.

MR. SCHRAUDER: We did take samples from those also.

MR. GROBE: Okay, interesting.

MR. POWERS: Thanks, Bob.

Lew was asking me to talk about susceptibility. This whole issues revolves around what's called primary water stress corrosion cracking. That's what started the issue on the head. That's been found in the industry that the alloy was referred to as Alloy 600 metal that's used for these nozzles is susceptible to cracking, given the right set of circumstances, and it's related to chemistry and stresses that are in the material, and temperature is one of the major factors.

And so, that's why we look pretty carefully when we talk about susceptibility ranking and go through the reactor system. The bottom head operates at a lower temperature than the top of the reactor. The bottom head operates at about 566 degrees; and the top head at our plant operates about 604 degrees, for example.

The pressurizer also operates at a relatively high temperature. And we took some, did some NDE on one of the lines coming out of our pressurizer, a vent line, to see whether it had showed any signs of potential cracking, and it did not, as a matter of fact.

And, those are some of the reasons why we believe these lower heads penetrations are not currently affected.

MR. GROBE: Okay, thank you.

MR. POWERS: Okay. Let me go on to the System Health Assurance Plan update.

We completed our discovery for the initial scope of the review of our systems. We've been talking about this in past public meetings. This morning in my office, I had all of the reports completed by the engineers, reviewed by our various reviewers, management reviewers, oversight reviewers. And, we're prepared to be delivered to Lew Myers for his sign-out as completion for inspection, and they're all in his office now for his review and final sign-out.

This really constitutes a milestone for us, although, all along we've been identifying issues as we found them within our Corrective Action Program. Finishing these reports really turns a corner for us in terms of completing a major portion of discovery looking through the health of our systems.

What we found as a result of all the reviews that have been done is there is a number of issues, particularly in the design calculation area, that we're going to be following up on. Corrective action documents have been written, based on potential issues. We need to determine the validity of the issues, the questions that are asked.

And we know that there are some good issues here for us to tackle. I have listed a few of them out here that we're currently working on. Instrument tolerances in calculations, for example. We have instrument set point drift and calibration accuracies, for example. Instrumentation accuracy, built into calculations that form the bases for our tech spec trip set point, set points.

But for other set points, we have not incorporated this level of detail similar to other older plants the vintage of Davis-Besse. And, we're evaluating that now in terms of what, the significance of that to our other systems, and that's ongoing.

The emergency diesel generator loading sequence is being studied. We need to prepare a detailed calculation on the diesel generator performance as it's loaded with step loads. You know, in a case where we lose our offsite power from the gridlines, our emergency diesel generators automatically start and automatically load in the plant to drive our safety systems.

Those safety systems have some rather large motors, rather large loads. And, how those sequence onto the diesel generator is something the engineers study to make sure that the frequency output of the diesel generator is maintained during that loading transient and that the equipment functions acceptably through it.

This type of analysis has been done at many other nuclear plants with engines just like ours. So, the engineers now are comparing how our plant compares design-wise to them. It's a very common diesel generator that's in use. And the diesels have been tested a number of times and the analysis has been done at many other sites, so we're following through to prepare that analysis for the Davis-Besse site.

Service water temperature, we talked about that a lot before. There had been work in the past to address the rising lake temperature in this region, and their affect on the plant. As part of that work, we lost some margin on our systems. As the temperature goes up from the lake, the heat exchangers don’t cool quite as well. So, in addressing that issue, we did not address it in a manner that we would preserve margins, and that’s what we’re going to go about now. We’re doing a lot of reanalysis of the capability of the system with some more recent tools, analytical tools, to demonstrate we have margins we need for safe operation.

The bullet here I have talks about high pressure injection minimum flow, was an issue that came up as part of the NRC inspection portion of the external oversight of our system reviews. This issue concerns very, very small leak in the reactor system and high pressure injection system responding to it and injecting. In the very long term, about 23 hours after that type of situation would develop.

If we would empty out our reserve water tank, and switched over our suction to the emergency sump at that point, there is a prescribed action to close the min flow valve, the minimum flow valve that goes back to our reserve water tank. And, there is a question on the table in terms of whether the high pressure injection pump is protected adequately for minimum flow.

And, for those of you that aren’t pump engineers, the pumps need to have a certain amount of small flow going through them, so that the pump doesn't vibrate and so the water doesn't ultimately overheat. Just from the energy of the pump turning will heat the water to where it boils and forms voids and that can damage a pump.

So, in the industry we try to ensure the minimum flow protection is provided. So, that's a comment we received and we're working on that issue now.

Then the last bullet is an issue that came up in our service water review on heat exchanger code relief protection. These are relief valves. Normally heat exchanger vessels designed for the ASME Code are provided with what's called code thermal overpressure protection. Particularly, if it's, for example, a fired boiler, where the pressure increases, just as it would on your stove on a teapot, there is a way for the steam, the pressure to get out; there's small relief valves that do that.

In this case, our heat exchangers are not fired, it's not a large source of heat, so there is a question of whether they need to have code relief protection; something that many of them haven't had since the original construction of the plant.

So, we're wrestling some issues here that are both new in the case of service water temperature, for example, and very old in the case of high pressure injection or heat exchanger code relief protection.

MR. GROBE: Jim, I just
thought of something on that last issue. Are you interfacing with the state code pressure injection board on that last issue?

MR POWERS: Have we
communicated with them? We haven't drawn them into discussion yet, Jack. We've been looking at the licensing basis and the code itself, but I think that's, that's a good point of something we do need to engage them, because they're very active at the site and they're one of our additional oversight resource that we can use to bounce this off of.

MS. LIPA: Jim, where do you
stand in your review of these issues for reportability, past operability?

MR. POWERS: Well, all the CRs
that go through the process, as I mentioned earlier, are checked off in terms of whether they involve past reportability. And there are two of them that you asked me to talk about; one was the containment air coolers and emergency sump. We had talked about those before the break.

And the, the containment air coolers, we're in the process of submitting a voluntary LER reporting the condition of the containment air coolers that was found in containment subsequent to the Boron effects on them, but we've looked at the structural capabilities of those containment air coolers, both the piping to them and the coils, and the coil supports and the registers and such, and believe that the structural integrity is good.

We have not taken the analysis through all the thermal capability of them. There was some Boron fouling of them when we took them apart, dismantled them for replacement, we found that there was some fouling on the water side, sludge and so forth in there. And so there is additional issues we were assessing on the performance of the CACs. So, we're going to provide an LER reporting of that situation to you. That's in preparation now.

We're also providing a supplement to the report that we made on the containment emergency sump. We had reported the potential inoperability of that sump, based on the qualified coatings in containment, unqualified coatings that we found.

And, also based on an opening that we found in the screenage of the sump, a relatively small opening, but bigger than the quarter inch design opening. And we had reported that to you in a relatively brief abstract last month, and based on these facts, we're providing an expanded response that gives much more detail on what we're doing and what we found.

MS. LIPA: What about these five bullets that you have here; are those still under review?

MR. POWERS: Yes, still under review. They're potential issues, and as we review them to determine, to determine the significance of them, then they will be going through reportability assessment. Christine, if they're reportable, we'll report them.

And so, another point that goes with our, our completion of the discovery for System Health is that we're moving into our extended condition reviews. We found some issues here on the Systems Review. We want to make sure that the balance of our, of our important risk significant systems are healthy as well. So, from an extended condition standpoint, we're moving off as part of our implementation plan, moving forward into building block to go through additional systems, and we'll be communicating that list of systems to you.

That's moving forward as well. There is a total of 15 of our important systems that we'll be evaluating to make sure they don't have similar issues in the design calculation area, as well as several other topical engineering design areas. Of those 15, 7 are already done, so there is 8 additional systems that we're going to be working on over approximately the next month and a half to determine their safety function capability.

MR. GROBE: Jim, before you go on, you and I had a rather lengthy meeting this morning discussing these issues. I just want to make sure I understand a couple of things.

You've identified issues regarding calculations as well as a number of specific technical areas, like high energy line break analysis, and seismic capability analysis and several others, where you believe that you don't yet have the extent of the problem identified. And if I understand what you just said correctly, you were going to broaden the scope of your review of the systems to address some of those issues and further understand what kind of problems might exist in the plant; and that will take roughly a month and a half, is that what you said?

MR. POWERS: Right. We expect in the range of approximately six weeks to do the initial cut through the systems.

MR. GROBE: Okay. And, a number of these deficiencies you've identified, either you've concluded are operability issues or could be system operability issues; and these are technical specification systems that are required to be operable during plant operation.

MR. POWERS: What we're looking

at for the starters here, Jack, is the systems that contribute greater than one percent of risk significance to our core damage frequency value. And the 15 systems that we have selected compose 99 percent of the value of our core damage frequency code.

So, from a probabilistic safety assessment perspective, we have, we've got the vast majority of the important systems composed in a set of 15 important systems at the plant. They also compose 98 percent of our large early release frequency value. So, these are truly systems that are important to safety at the plant.

MR. GROBE: I understand that. The technical specifications however require all systems to be operable; and, if you wanted to choose to modify your technical specifications and remove some of the specifications for other systems that are less risk significant, I suppose you could go down that avenue.

But we talked about meeting in the regional office later this month. I think we tentatively set the 23rd, for you to go through in much more detail the logic path that you've developed, where you've got some engineering issues that you've identified that could effect the operability of the systems, and how you chose the extent of the additional reviews you're going to be, and how you are justifying the need to not review all tech spec, technical specification systems.

So, this is a very important area, and I'm looking forward to that dialogue. And, hopefully, by the time we meet on the 23rd, if that's the final date, I think that's firming up, you can have a much more clear understanding of the operability impacts of these design deficiencies, and we can get into a little more detail on that subject.

MR. POWERS: Okay.

MR. MYERS: Jack, I think it's fair to say too --

MR. GROBE: You need a microphone, Lew.

MR. MYERS: I think it's fair to say, you know, a lot of these issues are just calcs that 25 years ago we may not have or may not completely understand, so we don't know that any of them really affect operability this time. What we wind up doing is generate a CR on any issues we find as we do these slices and then doing an operability assessment of each one of those, you know, as we find the issue; similar to what we do at other stations.

Just because you may not have a calc; when you get through you may have a calc and find out everything is okay. So, that's where we're at.

MR. GROBE: Appreciate your

comments, Lew. I wanted to make sure it's not, I'm not being misunderstood.

I'm not suggesting that you're required to do reviews of all of your systems. What's important to me is to understand which of these engineering deficiencies had a more safety significant impact on system operation, and if there are engineering areas where you had a significant impact on safety, what is your justification for the scope you have chosen, and making sure that we clearly understand that the standard that we need to come to, to approach restart, is a reasonable assurance that the systems are going to be performing correctly. And I want to start developing that foundation for an understanding of how you came to a conclusion that this plan will give you reasonable assurance, and we need to understand that before we can make any sort of a recommendation to our management on going forward.

MR. MYERS: I understand that. Thank you.

MR. GROBE: Could we go back to slide 18 a bit? Actually 17.

I think, Mike, this was part of your presentation. I wanted to get into a little more detail on the approach to Mode 3; and particularly in the area of system function. But first, I would like to talk, the third bullet down on this slide has to do with the emergency sump strainer. What is your expectation for completion of that modification?

MR. POWERS: Mike, go ahead.

MR. STEVENS: Okay, the emergency sump strainer modification was broken into two pieces. We expect that the top piece will be installed to support moving fuel. That's what we're working towards.

MR. GROBE: Okay. So, I understand now. So, you're planning on doing the modification which will increase the top strainer from approximately 50 square feet, I think you said the number earlier today was 300 square feet. That part of the modification will be done, but the bottom section of the strainer that goes down the stairs and around the corner, that part of the modification won't be done at this point in time?

MR. STEVENS: That's correct.

MR. THOMAS: So, do you stop doing the bore through the sump walls going down into the undervessel?

MR. STEVENS: No, we haven't.

MR. GROBE: Could you go into a little bit more detail on how you're going to sequence these things?

MR. STEVENS: I'm not sure I understand the question. We're going, the tech spec and requirement for moving fuel is to have the emergency sump. And we have a safe shutdown procedure that goes through contingency plans and alternatives for having the flow path through the, what is storage tank, and then back into the vessel.

We intend to install the top piece. We're not going to leave the hole there. We have to do something with that. We're working through those contingencies.

Part of what is prohibiting us from moving forward and finishing it will be the dose rates in the area and we'll have to sequence that so that we can get in and back out without getting into lock high rad areas.

MR. GROBE: Let me restate that to make sure. I think I understand, I think I understand what you said. You're going to continue with the modification work for the bottom section of the strainer, but at the point in time that the plant is ready to proceed with fuel load, you'll somehow blank off those strainer sections such that the sump has an integrity.

MR. STEVENS: That's correct.

MR. GROBE: Is there going to be some sort of post maintenance or modification test that will be done at that point to ensure the integrity of the sump? It's kind of an undefined situation.

MR. STEVENS: That's why we broke it into two pieces, so we could better define it. We will do the operability reviews required to partially close that portion of the modification, and all in accordance with. Do I understand the question?

MR. GROBE: Did that answer your question, Scott?

MR. THOMAS: Yes.

MR. GROBE: Okay.

MR. MYERS: I think one thing that is important here, we have our plans right now to stop somewhere along the way, but what we have to do is, and blank it out; but what we're going to have to do is we have a condition report on that. We'll have to do an engineering evaluation. Once again, the people that declare operability is our shift supervisors. We all need to understand that very clearly.

So, what we have to do is go over to our shift supervisors and convince our shift supervisors that this sump for the conditions we're at, that the straining module will meet its intended function, you know, and that being the support system for the sump. The shift supervisors, shift managers will make that determination.

MR. GROBE: Okay, and that's

where it should be. I appreciate that.

I don't have your valve numbers memorized, but I think a couple things came together for me as you were giving your presentation, Jim.

This RC 46 and RC 47 drain piping cracking, those are the valves that are on the lines that come from between the O rings on the reactor head. Okay. And the crack in the drain piping is a potential source of material that might have flowed down the side of the reactor vessel?

MR. POWERS: That's right, because it's down below the cavity seal.

MR. GROBE: Okay. Thank you.

Could we go to the next slide?

MR. MYERS: The answer to that question was yes, for people who couldn't hear in the back.

MR. GROBE: Right, you need to use the microphone, Jim.

The next slide, on slide 18, you indicate core reload in mid January. Are some of the systems that you're going to be reviewing for extended condition design issues, systems that are required to be operable for core reload?

MR. MYERS: Yes.

MR. GROBE: Okay. So, it seems like there is kind of a convergence of activities here. About six weeks of design reviews, which will discover additional problems likely, and so, that's a tentative date based on knowledge of what deficiencies might be identified in these continuing design reviews?

MR. MYERS: I don't want to peek for our operators, but what we know right now, if you go through the operational check sheets, we have a requirement that containment sump have some degree of operability to, to support core reload. That's not a tech spec out, that's an administrative item we have in our house.

We will look at that item based on having the containment, the permanent cavity seal in place and make a determination what we need to have in effect for core reload. Then the next step is, you know, putting the head on, going to Mode 5 and then Mode 4, and so on. And each one of those plateaus requires different conditions.

Here for the ECCS system to be a systems, that's where you get into the core of mitigation system, the ECCS systems, Emergency Core Cooling Systems; that's usually in Mode 4 runs with them, and I think that's 280 degrees here.

So, at that point, you know, we'll have to have a large portion of our systems operable. And, at that point, right now we're looking at mid February there. So, it's not as convergent as one might think.

MR. GROBE: Okay, I see. So, Mode 3, you're looking at, and that's the next slide, slide 19, your target there is mid February?

MR. MYERS: That's correct.

MR. GROBE: Okay. And then after, at the time you get to Mode 3 is when you're going to be doing that reactor cooling system normal operating temperature and pressure test.

MR. MYERS: That's right.

MR. GROBE: I understand. Okay. I appreciate you bearing with me. A number of these issues came together as you went through that presentation.

I apologize. There is one more thing. Bob Schrauder, you indicated that you had some contaminants on bottom head penetrations that were not associated clearly or easily visually associated with leakage coming down the side of the vessel.

Did you have any digital photographs that were generated of those penetrations prior to the cleaning? I was down there, but it's all been cleaned up.

MR. SCHRAUDER: I would have to go back and check the database of the pictures we have. Some pictures --

MR. GROBE: Yeah, if you have digital pictures of those penetrations, I would be interested in seeing them if you could email them to me.

MR. SCHRAUDER: Okay.

MR. POWERS: Okay, next slide.

Just wanted to briefly talk about one of the engineering focuses then on restart. Mike talked about Mode 6 at the time we took out this number of our CRs, we were at 189 Mode 6 condition reports that provide restraints going to Mode 6. So, there are issues that need to be dealt with. Those are actively being worked on.

We're prioritizing work at the site by mode change. So, Mode 6 being the first one. We're focusing a lot of attention on bearing down. And then the ongoing modifications that support fuel reload and containment health. I listed a few of them here. Although, there is a lot of work going on to improve the plant, as I'm sure a lot of the people there would tell you all.

So, that's it for the engineering update. Unless there is any questions, I'll turn it over to Neil Morrison.

MR. MORRISON: Thanks a lot.

For those of you who don't know me, my name is Neil Morrison and I'm the Owner of the Program Compliance Plan

Building Block. As Lew mentioned, I am on loan from Beaver Valley.

Today I'm going to provide you a brief update on the current status of my building block and also some future actions that FENOC is going to take in the area of program reviews.

As many of you -- well, as the board members may know that the Program Compliance Plan Building Block consists of two parts. The first part, which we would characterize as a Phase 1 Program Review, is for programs that were not associated with the degradation of the reactor vessel head. And we do a program review that is similar to a coached self-assessment that gets some independent oversight actions on the back end of it.

The second review that we do is a Systematic Detailed Review; and that's primarily focused on programs that were associated in some manner with the degradation of the reactor vessel head or programs that management has asked to have a detailed review on.

Currently, we have completed 65 Phase 1 Program Reviews, which is our intended target population. Of those 65, 19 are complete, paperwork is all signed off, approved. And the remaining 46, we're working through to close those out.

For Phase 2, which is our Systematic Detailed

Review, we had six programs that we intended to complete that are on the Restart Checklist. Four of those six are complete. You'll see them listed there; the Boric Acid Corrosion Control Program, the Corrective Action Program, the In-Service Inspection Program and the Operating Experience Program.

In addition to that, we had a pilot that we had performed prior to starting this activity, and it was Probabilistic Safety Assessment Program. And that report is in draft status. We will complete that action in January.

MR. HOPKINS: When you say complete; what does that really mean? I'm interested in how many actions you may still have coming out of it or what?

MR. MORRISON: My Building Block is a primary focus type of building block. We will go in and evaluate a program and document concerns or issues that we may have in a program using a Corrective Action Process; and out of that, then the program owners take those Condition Reports and resolve those issues and they develop an Implementation Action Plan to pull those issues together and manage them and resolve them and put the programs in a condition to support the restart of the facility.

MR. HOPKINS: Okay.

MR. DEAN: Neil, do you identify any of those actions as, in a manner of mode restraints as we've heard discussed with other?

MR. MORRISON: My building block does not do that. We provided initial characterization whether we think the issue might be considered as a restart, but then the Restart Station Review Board would take that condition report and confirm that evaluation one way or another.

Those issues that may affect operability of a component would get run through the control room and they would assign a mode restraint if appropriate.

MR. DEAN: You talking restart, you're talking overall recovery of the plant, not just the core?

MR. MORRISON: That's correct.

So, currently we have two additional programs that are under review right now at this time and they're near completion. We expect to complete them before Christmas. That's the Modification Program and Radiation Protection Program.

In addition to that, under my Building Block, I know this is one that I think the NRC has a lot of interest in, we are developing a Reactor Coolant System Integrated Leakage Program, which does include unidentified leakage.

And, while the program is under development, really aren't in a position at this time to go into great detail. I can give you a couple of features we have under consideration for that program.

One of the unique things that we're looking at doing is, when a plant heats up into Mode 3, which is normal operating temperature and pressure, but no nuclear heat, as mentioned earlier, we intend to do a baseline plant leakage. What's good about that is, you'll do this leakage calculation to determine what your baseline value is. In conjunction with that, you do a VT-2 walkdown, which is a normal activity coming out of refueling, which would confirm that you have no pressure boundary leakage.

Another thing we're looking at doing later on this, in 2003, we're going to heating the plant up and we'll be sitting in normal operating temperature and pressure for approximately 7 days. And at that time, this program that we have under development, we're going to pilot that. We're going to do some calculations at that time, and we're going to instill through some normal piping systems a known inventory loss in the cooling system and see how sensitive our methodology is to that, looking at small numbers. Make sure that we will be able to identify leakage at low numbers.

MS. LIPA: Question that I

have is, I guess I thought that one of Phase 2 Programs Reviews was the QA Program. Did that change?

MR. MORRISON: The QA Program, there is a detailed review going on and that's not really being managed under my Building Block. That's being done independent of my Building Block. And that is in fact ongoing right now.

MS. LIPA: What Building Block is that associated with?

MR. MORRISON: I don't think it's associated with any specific Building Block. It's being done through QA themselves.

MR. MYERS: Management/Human Performance.

MR. MORRISON: I stand corrected.

MS. LIPA: Trying to keep it all straight. Thank you.

MR. GROBE: Neil, before you go on, Jim had talked earlier about the installation of the Flus Monitoring System. And, I have two questions. One concerns experience on installation testing, preoperational testing of such a system, and calibration of such a system, and whether you're going to use this time frame, whether this Flus System will be in operation at the time of this first NOP/NOT test, such that you can baseline that and perform the preoperational testing at that time?

MR. POWERS: Our thoughts on that, Jack, is that we know that the insulation package has to be tight in order for that Flus Monitor to work well. And, our initial concept is, we would want to provide some sort of test to see if we could detect very small amounts of moisture with the Flus, but it's not linked at this point into the Integrated Leak Testing Program tests that Neil is describing here, which would be more, the Flus is very, it's localized to the lower reactor vessel area, where what Neil is talking about, we're really surveilling the entire Reactor Coolant System and we need to be able to detect leakage in steam generator cubicles, for example, and pressurized cubicles, beyond just the bottom head.

MR. GROBE: Is the Flus System going to be part of the RCS Integrated Leakage Program?

MR. MORRISON: Yes, it will be.

MR. GROBE: Okay.

MR. MORRISON: Overall, the Integrated Leakage Program, we are trying, we are in the process of putting together, we want it to be a model for the industry, something that they can take, you know, after we got it in place, and pattern their own programs after it.

MR. GROBE: One other question is, is there, where these Flus systems are used, I have no experience with these systems at all; are you able to use those on top head installations also?

MR. MORRISON: Yes, we can use them on top heads also.

MR. GROBE: But you're not planning on doing that at this time?

MR. POWERS: Not at this time, since we got essentially an unused new head installed, we're not planning that at this time, Jack, we're mostly focused at the bottom head region.

MR. MORRISON: The last thing I wanted to talk about this afternoon has to do with Program Reviews. I'm sorry.

MR. GROBE: One more question, Neil, I apologize.

MR. MORRISON: That's quite all right.

MR. GROBE: I'm very interested in the section of your RCS Leakage Procedure that deals with VT-2 Testing and Inspections. I've seen quite a variety over the years of approaches to those types of inspections; some are comprehensive inspections, some are less effective. Is there going to be guidance in this leakage procedure on VT-2 Inspection Procedures, or is that in your ISI Inspection Procedures?

MR. MORRISON: That's an interface with the ISI Program, but we will be looking at that interface pretty hard and make sure that the inspections are appropriate for what our goals are.

MR. GROBE: Good, because it's a particular area of interest of mine.

MR. MORRISON: Okay.

Moving on. The Program Reviews that we've been working on, we've seen a lot of benefit from those. One of our intentions is, an outcome of my building block is to make this an ongoing effort for Davis-Besse.

So, we're in the process of developing a procedure that's more attuned to doing this for an operating plant, and we're going to pilot that here doing program reviews. And, once we've got this working well for us, our intentions are to make this a FENOC-wide initiative.

And, to do that, we'll take this piloted program procedure that we're developing right now, turn it into a NOP, which for FENOC is FENOC-wide procedure. And, we will initiate program reviews through the Nuclear Services Department, which is based in Akron.

And to help support that activity, we're going to be developing a list of what we characterize as Priority Plan Programs across the FENOC fleet. And, we will select several of these programs and evaluate them every year FENOC-wide.

And the goal here is to look at these programs and look at them on a regulatory compliance perspective, how we've addressed industry guidance, interfaces and hand-offs, and we want to look at the implementation and verify it is being implemented successfully.

And, really, this whole thing all ties back to the root cause effort that occurred back in March. If you think back to the technical root cause effort that we had at Davis-Besse, one of the things that we identified was there were a number of barriers that had not provided the level of protection that we had expected. Those barriers were really plant programs. And, there was a population had let us down.

So, with this FENOC-wide effort, we want to go back and look at what we think are important plant programs, use as process to make sure they are actually providing the level of protection that we are expecting of them.

So, unless there is some other questions, I'm going to turn this over to Clark Price. I think Clark is going to talk about the O350 progress.

MR. MYERS: We already have a self-assessment process. In that self-assessment process, we lay out a yearly schedule of, say, what we're going to do. I would see this rolling in from a corporate standpoint into a program reviews yearly to improve the year before, for each side, and we'll do that across the sites.

And for some sites, you know, like we do have one boiler, boiling water reactor, we have a few pressurized water reactors. So, look at it on a site specific basis. So, Boron evaluation probably will not be a concern too much at the boiler.

But what I anticipate, a yearly group of programs that we would look at, and we've identified 65 programs or so now. We'll pick those and make sure they're giving us the performance they think, we think they should be. So, that's sort of the way we see this plan now. Okay.

MR. PRICE: If there is no other questions, I'll continue.

I'm Clark Price. I'm the owner of the Restart Action Plan.

One of the things I would like to talk about today is our overall progress on our 350 Restart Actions that we have at Davis-Besse, and how we're accomplishing those in our Return to Service Plan.

Starting off with that, I would like to go back to our basic Building Blocks for a moment and talk about those Building Blocks. There are seven Building Blocks that we started off with in our Return to Service Plan, that were designed to address all the areas, the causal factors that we identified in our original root cause on the head degradation.

This Building Block Plan, these Building Blocks have served us very well and continue to serve us very well; however, as you saw, and Christine talked about it earlier, the NRC 0350 Panel developed a set of Restart Checklist items that really, that is what we need to focus and address for restart.

Next slide. So, we started off with Building Blocks. Then we go to the Checklist items, and I'll be talking about a chart here shortly that we've designed to monitor both of those.

We developed a number of Davis-Besse O350 Restart Actions to address each of the 0350 Panel Restart Checklist Items. And, primarily those were derived from our Building Block activities. Although, as you heard here today, there are a few items that are outside the Building Blocks that are on the Checklist.

We've also developed performance indicators and monitoring tools also to help us monitor the progress of our plans and also help to schedule the inspections with the NRC. We want to make sure that we're ready for their inspections when they send out the inspection teams, and we continue to monitor that as we go.

One of the things we also did -- you can go to the next slide. One of the other things we did, was in our plans, we have, we took our plans and divided those into basically a discovery phase and an implementation phase. The Building Blocks were primarily designed to be discovery phase building block items, but our overall plan not only has to address the discovery phase, but also the implementation of anything we find during that discovery. And that's where we kind of combine all of that effort into the overall restart checklist and our restart actions to support that.

What you have in front of you right now on the screen is a monitoring tool that we use both on site with our senior management team and our owners of all the Restart Checklist Items and we also use this as a communication tool with the NRC to communicate our overall progress.

This report is designed, the lefthand column, the colored bars is our discovery phase activities. The far left -- and it's very difficult to read. We tried to get all of this on one page and it gets kind of small. But in