UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 E LAMAR BLVD
ARLINGTON, TX 76011-4511

July 3, 2014

EA 14-008

Jeremy Browning, Site Vice President
Arkansas Nuclear One
Entergy Operations, Inc.
1448 SR 333
Russellville, AR 72802-0967

SUBJECT: SUPPLEMENT TO THE ARKANSAS NUCLEAR ONE UNIT 1 DROPPED STATOR REGULATORY CONFERENCE MEETING SUMMARY

Dear Mr. Browning:

On May 1, 2014, members of the U.S. Nuclear Regulatory Commission (NRC) staff met with representatives of the Arkansas Nuclear One facility to discuss the apparent violation affecting both units related to the drop of the Unit 1 main generator stator as documented in NRC Inspection Report 05000313/2013012 and 05000368/2013012 (ML14083A409), issued on March 24, 2014. The focus of the regulatory conference was a discussion on the safety significance of the finding. The discussion included Unit 1 mitigating actions focusing on the use of temporary power to recover the electrical buses and Unit 2 procedural electrical power recovery actions.

In a meeting summary (ML14128A512) issued on May 9, 2014, it was noted that the regulatory conference was transcribed and that a copy of the transcription would be made available and placed into the NRC's Agencywide Documents Access and Management System (ADAMS). A copy of this transcript is provided as an enclosure to this letter.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC's Public Document

Room or from the Publicly Available Records (PARS) component of the NRC's ADAMS. ADAMS is accessible from the NRC web site at http://www.nrc.gov/reading-rm/adams.html (The Public Electronic Reading Room).

Sincerely,

/RA Cale Young for Greg Werner/

Gregory E. Werner, Chief
Project Branch E
Division of Reactor Projects

Docket Nos.: 50-313, 50-368
License Nos.: DPR-51, NPF-6

Enclosure: ANO Unit 1 Stator Drop
Regulatory Conference
Transcript

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DISTRIBUTION:
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ADAMS ACCESSION NUMBER: ML14184B252

☒ SUNSI Review By:		ADAMS ☒ Yes ☐ No	☒ Publicly Available ☐ Non-Publicly Available		☒ Non-Sensitive ☐ Sensitive		
OFFICE	RIV/DRP	RIV/DRP					
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DATE	7/3/14	7/3/14					

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Letter to Jeremy Browning from Gregory E. Werner dated July 3, 2014

SUBJECT: SUPPLEMENT TO THE ARKANSAS NUCLEAR ONE UNIT 1 DROPPED STATOR REGULATORY CONFERENCE MEETING SUMMARY

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ROPreports

Cause No: (None)

Nuclear Regulatory Conference with Entergy Operations, Inc.

Transcript of Proceedings

May 1, 2014

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TRANSCRIPT OF

NUCLEAR REGULATORY CONFERENCE

MAY 1, 2014

REPORTED BY:

KATHLEEN MCCURRY, CSR

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IN ATTENDANCE:

Greg Werner - Acting Chief, Reactor Projects Branch E, DRP

Kriss Kennedy - Director, Division of Reactor Projects

Marc Dapas - Regional Administrator, Region IV

Jeff Clark, Acting Director, Division of Reactor Safety

Jeff Circle - Team Leader, NRR/DRA

Jeff Mitman - Senior Reliability and Risk Analyst, NRR/DRA

David Loveless - Senior Reactor Analyst, Division of Reactor Projects

Leonard Willoughby - Senior Resident Inspector, Division of Reactor Safety

Mike Bloodgood - Senior Program Engineer, Division of Reactor Projects

Troy Pruett - Deputy Director, Division of Reactor Projects

Brian Tindell - Senior Resident Inspector, Arkansas Nuclear One

Peter Bamford - Project Manager, NRR

Vivian Campbell - Chief, Allegation Coordination and Enforcement Staff

Rachel Browder - Senior Enforcement Specialist, Allegation

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IN ATTENDANCE CONT'D

Jeremy Browning - Site Vice President ANO

Joseph Kowaleski - Senior Vice President, Entergy

David McKenney - Supervising Engineering

John Hathcoat - Assistant Operations Manager, ANO

Gary Sullins - Assistant Operations Manager, ANO

Richard Harris - Manager, Emergency Planning

Dale James - Director, Regulatory and Performance Improvement Department, ANO

John McCann - Vice President, Regulatory Assurance, Entergy

Bryan Ford - Senior Manager, Fleet Regulatory Assurance, Entergy

Stephanie Pyle - Manager, Regulatory Assurance, ANO

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P R O C E E D I N G S

OPERATOR SYLVIA: Good afternoon everyone. Welcome and thank you for standing by. At this time participant lines are in listen only mode. Following today's presentation we will have an opportunity for question and answer session. At that time please press star-one on your phone to ask a question. Now I'll turn the call over to our host, Mr. Greg Werner. You may begin.

MR. WERNER: Thank you Sylvia. Good afternoon, I'm Gregory Werner with the Nuclear Regulatory Commission. I'm the Branch Chief, responsibility for Arkansas Nuclear One and Waterford Nuclear Power Plants.

Welcome to the regulatory conference between the Nuclear Regulatory Commission and Entergy Operations. Today we'll be discussing the event that occurred on March 31st of last year involving a drop Unit 1 stator at the Arkansas Nuclear One facility.

The event resulted in identification of two preliminarily greater than green findings associated the with violations of 10CFR, Part 50, Appendix B, Criterion V for Instructions, Procedures, and Drawings, associated with the failure to insure that the overhead temporary hoisting assembly was designed and tested in

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accordance with approved standards.

A couple of administrative items; first, the closest restrooms are located out the door to your left past the guard station. In the event of an emergency, listen to the announcement over the intercom, if an evacuation of the building is necessary the nearest exists are out the front. Go out the doors to your left, or you can go out the doors to your right to the side of the building, and then our assembly area would be to the north towards the roads, we will proceed out in that direction.

The agenda is what's up on the screen. We also have an agenda that was printed and distributed. If you'd like to get one, it's located over there on the side counter, so feel free to get up and get an agenda. This conference is being transcribed and will be available publicly online.

As a reminder, when we speak, if we will introduce ourselves so the transcription lady can go ahead and get our names on the record. As a reminder to both NRC and Entergy personnel, if you wish to make a comment or question, please move to the microphone or move the microphone in front of you or go to the podium so the people on the phone bridge will be able to hear your the question or comments.

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Feedback forms are also available on the side table, and they will also be available online with the public meeting notice for this meeting. We would appreciate and request that you fill out the feedback forms.

So quickly, if you look at the screen, the agenda, we're going to do an introduction of participants and I would just like to have the main table introduce theirselves. We'll do some NRC opening remarks, summary of the violation, additional NRC opening remarks by Marc Dapas, Regional Administrator, the licensee Entergy presentation, we'll have some question and answers during that time from the NRC.

Once y'all's presentation is done, the NRC will leave the room, we'll caucus and determine if we have any other additional questions or need additional information, we'll come back in at that time. We'll ask those questions. Marc Dapas will then do a closing remarks, we'll adjourn the conference, and then we'll take questions and comments from members of the public.

So just so start out with introductions, again, as I said, I'm Gregory Werner, Branch Chief.

MR. KENNEDY: I'm Kriss Kennedy, Director of Division of Reactor Projects, NRC Region IV.

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MR. DAPAS: I'm Marc Dapas, Regional Administrator of NRC Region IV office.

MR. CLARK: I'm Jeff Clark. I'm the Acting Director for Division of Reactor Safety, Region IV.

MR. CIRCLE: I'm Jeff Circle, a Team Leader of the Division of Risk Assessment NRR headquarters.

MR. MITMAN: Jeff Mitman, I'm a Risk Analyst with NRR Risk Assessment and headquarters.

MR. LOVELESS: I'm David Loveless, I'm the Senior Reactor Analyst for Region IV.

MR. WILLOUGHBY: I'm Leonard Willoughby, Senior Reactor Inspector, Region IV.

MR. WERNER: Thank you. Entergy?

MR. BROWNING: Jeremy Browning, Site Vice President, Arkansas Nuclear One.

MR. KOWALESKI: Joe Kowaleski, Chief Operating Officer for the southern plants.

MR. MCKENNEY: My name's David McKenney and I'm Engineering Supervisor at ANO.

MR. SULLINS: I'm Gary Sullins, I'm the Manager of Shift Operations for ANO Unit 1.

MR. HATHCOAT: I'm John Hathcoat, Unit 2 Manager Shift Operations.

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MR. HARRIS: Richard Harris, Emergency Planning Manager, Arkansas Nuclear One.

MR. JAMES: I'm Dale James, Director of Regulatory and Performance Improvement, Arkansas Nuclear One.

MR. WERNER: Thank you. Again this is Gregory Werner. I'm going to have some opening remarks.

In accordance with the NRC's regulatory process after potentially risk significant findings identified and characterized by the significance determination processes as greater than Green, we offer licensees an opportunity for a regulatory conference.

In this case, Entergy has requested that a conference be held to discuss the issues and their significance. This conference is open to the public for observation. Members of both the public -- both those ins attendance here and via the phone bridge should be aware that this is a meeting between the Nuclear Regulatory Commission and Entergy.

During the meeting comments and questions will not be taken from members of the public. Following the conference, the NRC staff will be available to answer questions and receive comments from members of the public concerning matters discussed at this conference.

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On March 31st 2013, during the movement of the Unit 1 stator, the overhead temporary hoisting assembly transporting the stator collapsed, causing the 525-ton stator to fall on and extensively damage portions of the Unit 1 turbine deck and subsequently fall over 30 feet into the train bay.

The stator drop resulted in a Unit 1 loss of offsite power for approximately 6 days and a Unit 2 reactor trip. The drop stator ruptured a common fire main header in the train bay which caused flooding in Unit 1 and water damage to the electrical switchgear for unit 2, a small explosion resulting in a loss of offsite power to one vital bus.

As a result, one of the Unit 2 emergency diesel generators started and restored power to the associated safety-related vital bus. In response to the small explosion inside the Unit 2 electrical cabinet, the operators declared a notification of an unusual event.

On April 5th 2013, an augmented inspection team was chartered to assess the facts and circumstances surrounding the temporary hoisting assembly collapse.

The augmented inspection team completed the fact-finding inspection on May 9th 2013, and

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identified 10 unresolved items. Subsequently, a follow-up team was conducted July 15th through February 10th, 2014, to review those unresolved items. During the inspection the inspectors identified two findings of potentially greater than Green significance that were a violation of regulatory requirements.

The NRC assessed the risk significance of this event and preliminarily determined that there was a high safety significance, or the color Red, for Unit 1; a substantial safety significance, or Yellow color, for Unit 2. The NRC uses colors to classify the risk significance of each event. Green finding; green, white, yellow, red. With Green being the least risk significance and Red being the most risk significance.

Following the inspection on site, the NRC preliminarily determined that the finding constituted apparent violation of 10CFR, Part 50, Appendix Bravo, Criterion V, Instructions, Procedures, and Drawings. The violation was determined to be a failure of the licensees to insure that the overhead temporary hoisting assembly was adequately designed and tested. Specifically, licensee failed to identify deficiencies in the vendor calculation titled Heavy Lift Gantry Calculation, and the incorrectly sized component in the north tower structure of the temporary hoisting

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assembly.

In addition, ANO personnel failed to perform a load test of the temporary hoisting assembly.

These preliminary results along with an option for regulatory conference were communicated to you during an exit onsite that was conducted on February 10th, 2014, and is documented in NRC Inspection Report 2013 12, dated March 24, 2014.

This regulatory conference is the last step of the inspection process before the NRC makes its final determination on the significance of the inspection findings.

This event led to a unique situation where the NRC identified one performance deficiency and one violation alleging different risk significance determination for each unit. The differences in the risk significance related to a couple of factors; different operational modes, Unit 1 was shut down with reactor head off, fuel in the vessel, ready to be refueled as compared to Unit 2 there was 100 percent power. The other differences are they are completely different reactor designs. One is a Babcock & Wilcox the other one is a combustion engineering design. They have different systems and components that impact the risk significance of the findings.

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The purpose of this conference today is to allow you to provide your position in part or all with the facts and assumptions used by the NRC to make our preliminary significance determination, and to allow you to present new information that may assist us in arriving at the most appropriate final significance determination.

We also appreciate your views as to whether there's any information that may be relevant to the application of the significance determination in this case, including your position on the content and accuracy of the inspection report findings.

In particular, as discussed in the cover letter of the augmented inspection team follow-up report, please discuss actions that could be taken to mitigate the severity of this event and what range of credit should be applied and the basis for that.

If you have any additional information that is under development and is not currently available to be presented at this conference, please inform us of the nature and the date when the NRC would expect to receive that information. The NRC must receive that information in a timely manner so that we can review it and they can assess wit that information.

Please note that the primary purpose of

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this meeting is to discuss issues related, again, to the safety significance of the findings, which informs the outcome of the apparent violation. It is important to note that the decision to conduct this conference does not mean that the NRC has determined that a violation has occurred. The violation related to these findings being discussed today will be assessed in accordance with the commissions enforcement policy.

As a reminder, any statements, views, or expressions of opinions made by NRC employees of this conference do not represent final agency determinations or beliefs relative to the matter before us today.

Following this conference, the regional and NRC headquarter staff will reach significance determination and enforcement decision. Our goal is to issue the final significance determination letter by June 10th of this year.

Just to kind of give you a little background on our inspection activities, we determined that ANO personnel conducted extensive reviews of the event and the root cause evaluation and implemented appropriate corrective actions that served the subsequent lift of the drop stator and the Unit 1 replacement rotor of the stator were performed safely considering the lessons learned from the root cause

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evaluation.

Following the event and prior to subsequent return to power, NRC inspectors observed repair activities including the removal of the drop stator, observed the subsequent Unit 1 replacement stator lift, reviewed the corrective actions associated with repairing the damaged Unit 1 turbine structure, the fire main system, and both the Unit 1 and Unit 2 electrical systems, review the modifications and procedures related to heavy load lifts and we also observe training of your staff that they received on the advised requirements for heavy load lifting

Now, I'd like to turn it over to Marc for his opening remarks.

MR. DAPAS: Thank you, Greg. This is Marc Depas, Regional Administrator. The stator drop was certainly an unprecedented event that was significant from both the reactor and personnel safety standpoint. So it's in that context and is particularly important that at the conclusion of this conference we at least have a shared understanding of the facts and assumptions regarding our preliminary significance determination, and that we also have afforded you the full opportunity to communicate any new information to ensure that our final risk determination is as accurate as it can be.

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We communicated in the letter that I signed that Greg referenced, the follow-up augmented inspection team report dated March 24, we did clearly communicate the basis for our preliminary risk assessment. And as Greg indicated, there are different designs between Unit 1 and Unit 2, and that results in different systems and components that impact the risk significance.

So in my view further underscores the importance to ensure that we have the opportunity to fully engage and the shared understanding of the facts and assumptions. We ultimately may disagree with how much significance should be accorded to the different factors, but it's important that we have a shared understanding, at least, from, you know, the premise that we're operating from.

We acknowledge the corrective actions that were performed to ensure the plant was properly repaired and safe for restart. But I also wanted to note, as I mentioned in the cover letter to the subject inspection report that I just referenced, we had offered the conclusion that your staff did not address Entergy's oversight of the contractors involved with the stator lift and we independently determined that you the licensee did not ensure adequate supervisory and

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management oversight of the contractors and other supplemental personnel involved with the stator lift and that this contributed to the event.

So I'd like to, as part of the conference today, hear your thoughts regarding the actions you've taken to provide for oversight of contractors, how you evaluate that in going forward, what actions you've taken to ensure that in going forward approach you have adequately addressed that performance deficiency that was apparent from our independent review.

That concludes my opening remarks. I look toward to the discussion, and at this point, I'll turn it over to you, Mr. Kowaleski, to provide any opening remarks you may have

Thank you.

MR. KOWALESKI: Yeah, Jeremy Browning is going to do the opening remarks. And our presentation is going to address all the points that you made. It is constructive to first look at the Unit 1 risk significance and the Unit 2 risk significance, and discuss the evolutions.

MR. BROWNING: All right. This is Jeremy Browning, Site Vice President Arkansas Nuclear One, I do appreciate the opportunity, thank you for your time, to share additional insights and information that we

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believe will help us achieve that objective of determining the most accurate assessment of risk that occurred following that event.

As we were preparing for this, I wanted to make sure it's crystal clear that in no way, shape, or form are we intending to challenge the significance of the consequences of that event. We are simply trying to establish the most accurate picture of the nuclear safety risk following that event.

We take this commitment very seriously. The seriousness of this event, the people that are sitting on the Entergy panel were present on the day of the event, myself included. The most impactful piece of that is obviously the loss of one young man's life and the injury of several other employees. That will have a lasting impact on me personally, and the station, personally we take it very seriously.

And as a result, we will share with you the corrective actions that we took that were derived out of a very thorough and rigorous causal analysis which we broadened to extent of cause and condition. So we will share that.

We do appreciate the insights you provided to us in the augmented inspection team report and your risk analysis. We use that as a basis for our

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expanding further into possibly crediting some actions that we believe could have mitigated the risk. We also wanted to point out that following the event, the operators at the station took appropriate actions to place the plants in stable configurations, also minimizing the risk to the health and safety of the public.

We would also like to note that our safety-related equipment performed as designed, further reducing the risk to the health and safety of the public.

If we could, if we could move onto the agenda. As Joe spoke earlier, we're going to break the presentation down into two separate areas, initially, that's focusing on Unit 1 initially, and then we'll move onto the discussion on Unit 2.

We've strategically put a break right after the Unit 1 discussion, and again we'll take a break whenever it's appropriate, but we thought that would be a clean point to possibly allow ourselves to -- if there's additional follow-up questions because it is a different set of the parameters that we will move into when we talk about Unit 2. So we thought that might be a good breaking point.

The agenda, we're going to kind of paint

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the backdrop of the plant's immediate response, you know, what happened immediately just so we have a clear picture. It will be a very brief discussion, but I think it's important for us to understand what actually happened, the configuration of the plant, and the actions that we actually took following the event.

Following that, we will discuss a couple of areas on Unit 2, recovery of 4160 volt power and inventory makeup, and some success paths that we were developing as contingencies in the event the power continued to degrade, that being our offsite power which was always available to us and our safety buses that were always available to us. The conduit between the two has discussed earlier, had been severed.

So, really, that's the focus of our recoveries. How do we connect the available offsite power to the available safety, and we did have some additional contingencies that we were working on.

After the break, we'll shift to Unit 2. The discussion on Unit 2 is a little bit different in that the recovery actions that we'll be talking about on Unit 2 would be procedurally driven. The equipment was available, we really aren't developing operator or station-performed activities to implement those.

This is just simply walking you through

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the available resources that we had and our analysis as in some cases, there may not have been the appropriate credit applied to those areas. And then we will, at the end of presentation, talk about the site actions, the common cause, including fleet actions that were taken and, obviously, closing comments.

So if we can move on to the Unit 1 section. Already painted a little bit of an overview, this is what you're about to listen to. We're going to focus on the NRC event tree. When we're talking about 4160 volt AC power recovery, there's actually four sections if this.

The first section of it is what we actually did to recover power. Just so you understand what we -- it took to actually connect that available offsite power source to the onsite power source.

Then we're going to discuss three success paths that were being developed as contingencies in the event that we lost offsite power, or we lost one of our diesels, what would we do then? That's part of the way we do business. We're thinking about what could happen next.

So those recovery actions were already under development in that we would possibly lose one of our emergency diesels and what would it take to get that

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offsite power connected to our buses.

And the 4th item that we will talk about is inventory. Making sure that we had available inventory for our spent fuel pool which was flooded up, had over 300,000 gallons of water on top of the fuel -- active fuel, but we did recognize the need to establish inventory control.

As we go on through the Unit 1 discussion, we recognize that crediting those, there is no approved process to credit actions that we were proposing. So what we did is we used known tools that are already out there for assessing risk, and we tried to say how can we apply those known tools to the methodologies that we would be implementing to give credit to action and come up with a method for crediting those.

I think that is all I had on the overview, so I think we're ready to actually move into the Unit 1 discussion.

MR. SULLINS: Mr. Browning, this is Gary Sullins, you spoke to the spent fuel pool, I think you meant the fuel transfer.

MR. BROWNING: Both. In our succession on make up, our make up capability would have provided make up both to the spent fuel pool and the reactor, but

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thank you.

MR. KOWALESKI: Good afternoon. This is Joe Kowaleski. Just add one other item to that as we're talking about the actual installation of the power supply from the offsite startup one transformer to the safety buses. That was actually installed and available for service in 4.4 days. Gary is going to discuss the time to full recovery is 4.8 days, so in the actual event we have we had offsite power established prior to and within the timeframe of core recovery.

MR. SULLINS: Good afternoon, I'm Gary Sullins, Manager Shift Operations on ANO Unit 1. I supervise the shift managers for Unit 1 and then the senior license holder to that unit. I also serve in the role of TFC manager in our emergency response organization. In that role I report directly to the emergency plan manager and coordinate development of repair and recovery actions in the TFC working with our operations, maintenance, and engineering coordinators.

On the day of the stator drop event, I provided oversight for control room activities throughout the day, and in the days and weeks following, I served in the role of supporting the engineering and how to support organizations in defining strategies for our recovery.

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MR. MCKENNEY: My name is David McKenney and I'm the -- right now I'm currently the Engineering Fix It Now Supervisor at ENTARK (unclear) 1. I've got going on 27 -- a little more than 27 years experience, all of it in engineering, and before that 6 years of construction experience. I was the engineering coordinator and the TSE the evening after the event. We'll talk about what the engineering activities were going on associated with that.

The engineering fix it now team is -- one of our normal businesses is to provide temporary power during outages and for other -- like bus outages and some of those kind of things. So we're very familiar with the ability to get power to where we need it.

MR. SULLINS: To remind you of the structure of our presentation, the success paths for 4160 volt power recovery are built upon what we actually did to substantiate their viability and also recognize that those success paths were in our contingency plans in the event that power degraded.

So what we'll start with, initial conditions that applied both on the day of the event with the plant responding as it did, and these initial conditions would also apply for certain of the sequences in the risk assessment had equipment failed such as our

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emergency diesel generators.
We were on day 7 of our refuelling outage with our fuel transfer canal flooded. That provided for us a time to boil of 12 hours and a time to core uncovery of 115 hours or 4.8 days
MR. MITMAN: If I could ask a question of clarification on that? This is Jeff Mitman from headquarters. The 12 hours and the 115 hours are a little bit longer than what I'd seen previously. Two questions; first is, could you supply the basis for those times? And the second question is, those are the times that we currently understand were the conditions that they were in. Also of extreme importance is what the operators thought they had at the time of the event. And so could you speak to how much time they thought they had when the event happened?
MR. SULLINS: Yes I can, Jeff. We can provide followup calculations from our insurance staff for the times presented. I don't have with me, readily, the times that we -- we calculate daily an estimate, a bounding estimate for time to boil and time to core uncovery, and those times were short and I'll have to get back with you for the exact times that were posted in the control room and available previously.
MR. BROWNING: Gary, are the estimates

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that are done are any of those recoverable, are they documented?
MR. SULLINS: Yes they are.
MR. BROWNING: So we can provide the -- from that day with the estimate?
MR. SULLINS: Yes we can.
MR. DAPAS: Just an over arching question. Our preliminary risk determination we had a different subsequent regarding time to boil and time to core uncovery.
MR. MITMAN: The initial assessment's a little bit shorter than those times, but not to the point to -- the human reliability analysis isn't sensitive enough to distinguish between what they have, what's currently being estimated and what we used. So it's not going to shift the results, but I'm not sure where the numbers are coming from and I'd like to get a look at those.
And likewise, what the operators thought is probably more important then what the times actually were because that's what everybody is going to be working towards is what they think is the amount of time that they have, not how much time they actually have.
MR. SULLINS: As a result of the stator drop, we had a loss of availability of our three

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non-vital sources to our vital switchgear. Those being our startup one and startup two transformers and the alternate AC diesel generator. Our vital switchgear were unaffected and operated properly once re-powered from the emergency diesel generators.
Also note is that we had available to us 480-volt power within our power block from local distribution, we commonly refer to it as the London Line. On the day of the stator drop event, that power source was used for non-vital equipment. This supports the spent fuel pool cooling function and in days that followed, this power source was used to recover load centers for our 480-volt distribution system. And you'll see later in our presentation how this available power provides options for us to respond.
On the day of the event we chose to staff our emergency response organization, and for the dominant cut set and the risk assessment we would likewise be in an alert condition and have available to us that support structure provided by our ERO.
We were in day seven of a fueling outage and that provided for us substantial support of human resources. We had 295 craft available, 45 electricians, this is around the clock support, approximately 40 engineering personnel, and 60 operations personnel. And

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those are the operations personnel available to support Unit 1. It does not include those that were involved in Unit 2.
To ground our discussion, we've reviewed your risk assessment and have focussed on key nodes in sequence 19 which is called out in your report, which involves the loss of both emergency diesel generators and then other sequences where loss of one emergency diesel generator can influence the probability of core damage.
We'll be talking about, as Mr. Browning mentioned, recovery paths that were available to us for 4160-volt power as well as inventory control recovery.
Our objective, just to summarize, is to provide a technical basis for success paths for that dominant cut set where both diesel generators or one diesel generator is lost. Three of these involve recovering 4160-volt AC power and the three success paths were those contingency plans that were developed in response to the event.
We also will talk about a 4th success path involving use of 480-volt power to provide force flow makeup to the reactor coolant system.
MR. KOWALESKI: This is Joe Kowaleski, just wanted to point that out that of the three

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4160-volt success paths were on the board and being evaluated in scope in response to this event as contingencies in the event that something happened. So in terms of determining what we could do, these were already on the table.

MR. DAPAS: I think that's an important distinction there. It's not that these alternative success paths could have been pursued, you are communicating to us that they actually were being pursued or at least you were going through the thought process and what would be involved to establish power via those alternate routes. Is that correct?

MR. KOWALESKI: Yeah, that's correct. So given the picture, we've got two diesel generators, a very stable condition, and so evaluating how to restore offsite power, the way we chose to do it, from start up one to the safety buses was done in a way to provide flexibility for the ultimate recovery. Lay down areas, travel paths so it was well away from what we needed for construction activities. And it provided operational flexibility for future testing and activities to restore the electrical part.

So it's more complex then these options. These options were on the board, being evaluated by the TSC as contingencies in the event that we had a problem

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with the diesel or some kind of a problem with completing the offsite source that we ultimately did.

MR. BROWNING: And hopefully through our presentation we're going to demonstrate to you that the scope of what we actually did was very similar to the scope that was in these contingency plans, so the materials, the resources, and the people that we would have needed to do this activity, we could have shifted the plan from what we were actually doing, which was based on actual planning not the ones proposed in risk analysis, but they are so similar in nature that that change in course could have happened pretty quickly.

MR. CIRCLE: This is Jeff Circle from headquarters. Did these contingencies exist in any way, shape, or form prior to the stator drop as standard contingencies that you normally take? That would require, you know, putting equipment in the warehouse, getting it prepared, procedures or anything like that?

MR. BROWNING: The actual specific contingency that we're talking about today would not have been fully developed; however, the processes that we would have used for temporary power for a normal refueling, we do these kind of things to prepare ourselves for a refueling outage. So the scope would have been the same. We're going to take power through

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here and we're going to run a capable to there and all the relaying and the metering that you might need to do to do that would be on the table. The change would be where is the source of power and where do I need it?

MR. CIRCLE: Was the equipment staged?

MR. BROWNING: Yes, sir. We will discuss that as far as we were going to do some circ water pump cables and some other work on some site where we had the craft there, the resources there, the materials there for similar work with similar components, we just changed where those components would be connected.

MR. KOWALESKI: This is Joe Kowaleski, just to be clear, so all the materials needed to execute these options were on site? They were not staged for this job, but they were immediately available on site?

MR. BROWNING: That includes the human resource and the skills and the training to implement them.

MR. CIRCLE: But no procedures?

MR. BROWNING: No procedures were developed at that time. They were developed in order to implement.

MR. DAPAS: I think it would probably be appropriate that you were planning to go through and explain to --

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MR. BROWNING: Yes, sir.

MR. DAPAS: I understand your question. I think it's a valid question. I think we'll -- you were going to give us the opportunity to engage, right?

MR. BROWNING: Yes, sir, if we don't hit your expectations when we flip past the slide, ask a question.

MR. CIRCLE: Well, we're not wallflowers.

MR. SULLINS: Thank you for the question. Both for our actual response and for postulated equipment failures, our priorities would be dictated by the circumstances. And what we mean by that is we're looking at our defense in depth for our five key safety functions. What's our status of the plant? If the TSC is activated as it was that day and in the event of blackout condition, we're assessing those and establishing priorities. On the day of the event the plant was stabilized quickly and we had two trains of decay heat removal on this support equipment in operation.

The priorities align with those key safety functions, protecting the electric power, protecting decay heat removal, protecting the spent fuel pool cooling. With the conditions that existed in our plant it was also very important to us to protect our

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personnel with changing plant conditions, electrical safety, structural safety were very important to us.

And as Mr. Kowaleski had mentioned, we were factoring in -- given that we were stable with two trains in operation, we're looking at taking a longer term view of risk and how we recover and what we ultimately chose to do with our recovery of offsite power.

On the day of the event we recovered promptly our decay heat removal function, our spent fuel pool cooling. In the week that followed, we reliably operated emergency diesel generators with no challenges, and beyond that, we reliably operated our two trains of decay heat removal.

As we've already discussed, we chose -- we developed and chose a recovery path for 4160-volt power. In light of the stable conditions and the time margin that was available for us with the condition, too, of our shut down operations protection plan flooded up to implement an optimum electrical recovery.

That recovery that was implemented was made available to my staff and operations in 4.4 days. And to be clear on what we mean by available, it was tested energized up to the last breaker on which no modifications were made and operating instructions and

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briefings have been provided to our operators in the form of night orders. So in the event that we needed to use this source on a emergency basis, it was available to us at that time

MR. MITMAN: Could you speak to why you waited, what the thinking was behind waiting another day and a half, approximately, before you re-energized --

MR. KOWALESKI: -- refer to the process diagram.

MR. SULLINS: I'll answer briefly. It was to complete the review process to formally approve the temporary modifications design reviews.

MR. MITMAN: Did you have to do any further testing on the buses to see that they were okay to take the power?

MR. SULLINS: No sir, we did not.

MR. BROWNING: If you look back at the slide that talked about priorities. We were making decisions based on actual plant conditions. One of our priorities is we were not going to challenge one of those emergency diesel generators. We were not going to challenge a bus.

A different mindset would have come into play if one of those diesel generators would have shut down. That would now take that priority off the table.

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We don't have to protect that diesel anymore and that breaker would have been closed by the operators just as Gary's stating it. The subsequent days we've discovered nothing that would have changed our approach and that breaker would have powered that bus up without challenge.

MR. SULLINS: The process -- I was involved in that decision. That process that applies is our temporary modification process, and I had discussions with the lead for the recovery team, our design engineering manager, about whether we met the criteria for an emergency team mod and actually placing it into service, and my position was that we did not. So we waited for the formal approval to be completed to place it into service.

MR. BROWNING: Again going back to the other -- again, this is Jeremy Browning, Site Vice President ANO -- we would have met the criteria for emergency temp mod had one of those diesel generators failed in some way because the safety function would not have been met and that would allowed that process to continue forward.

MR. CIRCLE: Right. And this is Jeff Circle. The thing is that if the diesel had failed, one of the reasons why it failed is the fault with the

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switchgear. So it wouldn't have been a 4.4-day recovery, it would have been a little bit longer. Because you would have to have measured the switchgear to ensure that the fault, the condition had cleared.

MR. KOWALESKI: I would clarify that slightly. The timeframe for the 4.8 days available to, quote, uncover the start at the point that you lost both diesels, not on the day that stator, but that point in time that both diesels failed, you would have had 4.8 days to put that in service.

MR. CIRCLE: Right, but you would still have a lot longer time then you had on that particular event. So that event, the diesels were running, so you had the temp mod right up to the last breaker. What we're talking about -- we're skipping ahead a little bit because this is part of the risk analysis, that you failed two diesels, you're in the station blackout condition and now the only power that you have is through the temp mod, but you don't know what caused the diesel's to fail.

So there would be some additional work that you would have to do prior to restoring power. That's all -- that's why we're asking that question.

MR. DAPAS: I think the importance of discussion here is to try as realistically as we can to

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reconstruct, if you will, what conditions would have existed had you needed to exercise these alternative recovery paths here, since a lot are looking at those as being available here to address the risk significance, that we describes following an assumption of the failure of the diesel.

So in my view that's why it's important on timelines here, we need to be careful here when we're saying on saying an extensive period of time, you know, those are all subjective terms. Just try and refine, you know, what is the actual time estimate if there needed to be an understanding of the root cause -- the cause for the diesel failure here, does that impact the bus and would you have to do some degree of testing, right, before you connected your alternative power source to the affected bus.

Understanding that, just what would be a realistic estimate of that time?

MR. BROWNING: And hopefully, through our presentations we've discussed the contingencies, we will show the margin that we would have had in the event that we would have lost one of those diesels and decided to implement one of our contingencies, as opposed to what we actually did.

The only real discussion around actual is

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to paint the picture of scope and what it took to do it and compare that to what we would have done in the event that we had a failure. And, again, if we get to the point where we're talking about the timelines and we haven't met your expectations, we will clearly provide the information that we need to meet those expectations.

MR. SULLINS: Regarding the question on assessing the condition of the bus, we would well confer the dialog on the indications available to the operator and how we would access that if that's useful.

Okay. The next phase of our section is David McKenney will describe what we actually did to recover power from Startup No. One.

MR. MCKENNEY: First thing I wanted to do was kind of go through our electrical distribution system. So everybody has a baseline knowledge on this before we start talking about options that we take. So I'm going to point to the screen up here, so if you follow along with me, it will help us with that.

We have, there's basically five sources of power to our vital AC. There's a Startup 1 transformer, which is fed from offsite. There's a Startup 2 transformer, which is shared with Unit 2. There's the alternate AC diesel generator, which is -- it also shared with Unit 2, can provide power to either

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the non-vital on Unit 1 or the vital on Unit 1, the non-vital on Unit 2 and the vital on Unit 2. So it has lots of capabilities to go to different places.

And, of course, we have the emergency diesel generators that feed the safety buses. So the way the normal power comes into the plant, is it comes in from one of the Start transformers to the non-vital. You can see this line right here shows the difference between the non-vital above this line and vital below this line. And so, anyway, there's -- and then from there it goes from --

(Noise from the bridge phone line)

MR. WERNER: This is Greg Werner, somebody with the NRC doesn't have their phone muted. Could you please mute your phone? Thank you.

MR. MCKENNEY: I think we got it. All right, so this is the non-vital, which we call A1 and A2 and then from there it feeds through to vitals. This is the red train, and the green train, 4160, and then it cascades down through the 480-volt systems to provide the power.

So this is the situation we were in before the event and the lines that are colored red is the lines that were energized. Any questions on that? Okay.

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So what this figure is designed to show you is what was actually damaged by the stator drop. And that's inside this shaded box here. The little figure on the thing doesn't have shaded, but it has a red dotted line around it. And what you can see is, is when the stator fell, it made unavailable the non-vital link between offsite and the vital. So what we're faced with was how to get power from the top, above the box, down to the bottom, to get power back if the diesels were to fail.

MR. MITMAN: At the time of the event did you know the status of 2A9 and whether the 2A9 bus was functional or not?

MR. MCKENNEY: There was no indication to the operators it was nonfunctional. We -- so the damage to the 2A9 bus is actually in the back where the termination points to Unit 1. So the bus --

MR. MITMAN: Jeff Mitman again. Let me rephrase it a different way. Did the operators think that they could use 2A9 immediately after the stator drop?

MR. HATHCOAT: This is John Hathcoat, the Unit 2 Shift AO1, we had -- the report came from the field about 1:30 in the afternoon that there was potential damage to the back of 2A9. The feeds from the

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A1, A3 vital and non-vital Unit 1 back of 2A9 was damaged, but at that point Unit 2 believed that we needed to assess what we had.

Up to that point and even after that point on the Unit 2 side it was fully available and the operators would have used it if need be. It is a shared load between Unit 1 and Unit 2, so the functionality is really dependent on if there's anything damaged, challenging the functionality, we would call it unavailable or nonfunctional, but it was available.

MR. MITMAN: But there's visible damage to the 2A9 bus, and so far you haven't talked about testing the 2A9 bus to see whether it's capable of performing its design function, and I'm surprised that you would contemplate energizing a 4,000-volt bus without doing at least a little bit of testing on it unless you were at a point where it was your last resource.

MR. HATHCOAT: Absolutely. And from a Unit 2 perspective, you know, H B Robinson was mentioned in the control room four or five times, I was in there. And that question came up, and it was isolated -- what we knew -- the report from the field was it was isolated to the Unit 1 side.

And from the Unit 2 perspective, you

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know, I interviewed the controlling supervisor, the SDA, I was there, and if we were in a blackout condition, and I'll talk more about that in the Unit 2 section, but, yes, it would have been pursued.

The question came up, you know, locally going down there and looking at it. From a relay tech standpoint we would have gone down, more than likely, and opened up the back and inspected and make sure it was just isolated to the Unit 1 side before we pursued on Unit 2.

MR. KOWALESKI: To be clear, though, the damage was on the connection points on the output of the Unit 1 breakers, very visible and easily accessed and assessed. So there was no damage to the actual bus, the bus work supply from the alternate AC diesel, no damage to any of the Unit 2 breakers or the feeder breaker to the bus.

The damage was at the termination points on the output side of the Unit 1 breakers, and the breakers themselves were not damaged.

MR. MITMAN: You know that today, but the people in the control room at the time of the event did not know that, so it's not a question of what the bus was capable of doing, it's a question of what the operators in the control room thought they could do.

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And not only is there damage to the 2A9 bus, but there's water on the floor in a room with 4,000 volts of energized equipment.

It's a -- plant personnel have to be very careful about what they're doing that the equipment that is functioning and themselves, and I just want to draw the distinction between what we know today and what was known at the time of the event. And what we knew they could have done at the time of the event today is not what the control room knew at the time.

MR. BROWNING: So John has the direct knowledge of what the control room would have known at the time.

MR. HATHCOAT: I was in the control room at the time. We were stable on the Unit 2 side, so we did not have to pursue energizing 2A9, but, you know, our procedures, station blackout procedures, loss of offsite power procedures, standard tasks, we're trained on that.

That's one of our major recovery strategies, and I'll talk more about that, is to look at your blackout condition for safety function. We're going to follow our procedure and energize 2A9 using the station blackout diesel.

Now is it a proven action, knowing that

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there's potential damage to the back side of the 2A9 bus? Absolutely. We don't have time, we would have had time to engage the technicians, I sent them down there looking at the back up 2A9, make sure that it was isolated just to the back feed on the Unit 1 side, and it shouldn't have been any issue at all moving forward with energizing one of our vital buses.

MR. DAPAS: I think the key here is -- this is Marc Dapas -- I think the key there is what in your view do you think the operators and staff would have been able to assess and I understand now that your view there was that the damage was isolated to what the Unit 1 breaker output determination?

MR. HATHCOAT: There's two breakers --

MR. DAPAS: The question in my mind is, is that readily apparent to the operators by going down and looking at that and making that determination, or is that a function of what you've been able to determine, you know, after the fact there? What information was available to the operators and what input was there for their decision making, trying to understand that here and looking back.

MR. HATHCOAT: You can easily discern that the queues are kind of split out, that it was isolated to the A1 and A3 feeds to Unit 1. With that in

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mind, you know, the operators would have, knowing what they did that the cable was pulled across the train bay, and at the time they had known that, hey, as isolated Unit 1 we could have moved forward with Unit 2.

Now the information came from back from the field about 1:30 in the afternoon. Now talking to the shift manager at that point later he said, you know, it might have been a good idea in a blackout condition to send the relay techs down just to look in the back just to confirm that it is, you know, isolated to A1-A3 before we pursued on it because we would have had time in a blackout condition.

So, yes, they definitely would have pursued it for our procedural direction to restore power if needed.

MR. CIRCLE: This is Jeff Circle. How was the accessibility at that time if they had to do a detailed examination of the switchgear?

MR. HATHCOAT: Well, we couldn't get down to it 'til around noon or after this, but at that time, you know, we didn't know -- there was no knowledge that the blackout diesel on 2A9 was damaged. It wasn't until we got down there, until about 1 o'clock is when we actually noticed.

MR. TINDELL: This is Brian Tindell the

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Senior Resident at Arkansas Nuclear One, I think we're getting confused between availability for Unit 1 and Unit 2. I think most of what you're talking about is availability for Unit 2, but we're talking about the Unit 1.

MR. HATHCOAT: Absolutely. And I'll talk a lot more about the Unit 2 and hopefully clarify that.

MR. DAPAS: Just one overarching comment. I think it's important here that we're understanding the basis for your assumptions, so if our questions are leaving you with the impression that we've already reached a determination, it's really to understand the basis here and how you considered the various factors here, you know, IE: If the bus needs to be tested, did you consider that? How did you factor that into your timeline?

MR. FORD: I think we might answer those questions better when we get into the strategies.

MR. MCKENNEY: First thing we're going to talk about is what we actually installed, post event, and that's just to show you the basic electrical layout of that and a physical overhead view of that.

And so what we're going to do is go through -- this is a picture of the Startup 1 transformer that was on the previous slide. And what we

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did there is we hooked a cable between the Startup 1 transformer and a temporary 4160-volt breaker that was located in our transformer yard. Ran another capable around the south side of the Unit 1 turbine building, away from the damaged area and tied it to the A310-410, which is the cross connect between the two vital buses.

We were actually able to install this in 4.4 days and had it energized to this point here(indicating). All tested and energized up to that point.

And where we spliced this cable, and this portion of the circuit was not impacted by any damage or any of those kind of things, so that portion of the circuit was still intact.

MR. LOVELESS: Temporary breaker was onsite for it, or was it brought in?

MR. MCKENNEY: No, we brought that in, ENTARK, Entergy Arkansas had that, and it was here the next morning, after the event.

MR. SULLINS: Very good question. We're talking about what we actually did when we talk about the success paths that are modeled in our risk assessment the breaker is not a part of that strategy.

MR. MCKENNEY: This is just an overhead view showing the layout of -- here's the Startup 1

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Transformer as it exists, it's normal location. We put the temporary breaker about approximately 50 feet away, then we ran the cable around the south side of the plant and to our vital switchgear area.

This area here that's designated the train bay, that is where the stator fell. And these two boxes here, I know it's hard to see, that's our non-vital A2 and A1 switchgear.

MR. WERNER: As a reminder, if you wouldn't mind just saying what page number you're on, we do have folks from headquarters listening in.

MR. MCKENNEY: I'm on slide 17. This is slide 18, and this is a photograph of the temporary breaker. You can see the general location right here that we put in transformer yard. This is Startup Transformer No. 1. And this is the stator where it landed after the event. So you can see we have temporary cables here you can see coming in and out of the breaker from the transformer and then going down the opposite end of plant, back around to the vital switchgear.

This is slide 19. This is showing the general scope of the actual installation that we installed. And you can see that it might be a little confusing. It's seven -- since we had to run parallel

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conductors per phase, there's seven cables and one neutral, so the actual length was 50 feet and 500 feet, so it's lot of, there's some parallel runs on that.
MR. CIRCLE: We did have that question.
MR. MCKENNEY: Yeah. There's 28 splices or terminations, some of them were splices, some were terminations, 4160-volt that we installed for that.
MR. MITMAN: So, this will come up a little bit later, but you used about 4,000 foot of cable as I understand it, right? How much additional cable did you have on site?
MR. MCKENNEY: We had scheduled to replace our circulating water pump cables, which is in our intake structure, so we had quite a bit of cable on site to do that particular job. We had not started that job yet. So we had a lot of cable and the termination kits associated with replacing that cable, this 4160-volt cable, so.
MR. KOWALESKI: We had more, but you don't know an exact length?
MR. MCKENNEY: We had enough to do the alternate, we did bring in cable to finish this particular option, but the subsequent options, the capable length is a lot shorter and if we'd gone into that situation, we'd have done that.

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MR. MITMAN: So, again, I'm getting a little bit ahead, but the concern is how many of these options you could do? You obviously had enough to do this one, but if you had to do one or two additional ones, you might have run out of cable.
SPEAKER: This is headquarters. We're having a hard time hearing you, Jeff, could you please speak up a little?
MR. MITMAN: Okay.
MR. BROWNING: How much cable did we actually have on site, how much did we use for this?
MR. MCKENNEY: I can get you those numbers at break. I've got them in a book back here.
MR. DAPAS: I think the intent of the question was to understand if you had to pursue more than one contingency option there did you have sufficient cable for that?
MR. MCKENNEY: One thing is, and it's not listed in our presentation, if we really had to do this we could have run this cable a lot shorter than what we did. And that's what we're going to talk about in a moment.
MR. CIRCLE: Jeff Circle, just to clarify, and then I'll finish, had it not been for the fact that you had already scheduled the circ water pump

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you would not have this much capable on site?
MR. MCKENNEY: That's correct.
MR. BROWNING: But to that point, we not be lifting the stator if we weren't in a refueling outage performing this work.
MR. CIRCLE: Right, but this particular outage, it was fortuitous that you had cable on site available.
MR. MCKENNEY: Cable is not terribly difficult to come by in the timeframe we're talking about. We were able to actually get the cable here in the timeframe we're talking about. But we did have enough cable to do multiple of these options on site.
I want to talk a little bit about the implementation process because that's going to be important as far as how do we get to the point that we identified the need for one of these temporary installations, to actual implementation of those installations.
And so, we had -- I was in the TSC and we were working on multiple options because of the condition we were in with just running on diesel generators from the engineering and a station perspective that's not a very comfortable position to be, so we were continuously looking at additional

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options, contingency plans because if we lose a diesel generator, then we'd want to be able to respond in a reasonable fashion.
And so the implementation would be under our temporary modification process and our work management process. I'll go through this flowchart a little bit with you. This kind of describes our processes.
So if you'll look at the top here you'll see where they have the TSC or OCC or OPS where engineering identifies a need. Engineering would define the concept and scope and then at that point, once we define the initial concept and scope, depending on the urgency, we would provide those directions to planning, in which case they would start the planning process and get instructions to the field for the start of installation.
A lot of the stuff that we actually install, like pulling capable, it's pretty straight forward, so you don't need a lot of detailed instructions for that, but they were working under our processes.
So as they're installing and testing the configuration, they're providing feedback to engineering as we are refining the scope. And then if there's any

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changes to what engineering needs we provide that back to planning, which kind of completes the circle on -- to make sure that we're linked up.
Because what we're doing here is we're running in parallel paths, right? One is the installation, one is the documentation and approvals associated with the temporary modification.
So this right here, the available for use, that's when the testing's done, the installation's done, oftentimes the engineering will lag a little bit behind that if you're in a parallel path environment. And for the installation we actual installed, that available for use, that's the 4.4 days we're talking about. It was installed, it was tested, and it was energized up to the point that all OPS had to do was close the breaker to provide power to either of the vital buses.
So if there was an immediate need or if we were to lose a diesel generator or something, we could have invoked an emergency team on and placed it in service. But the path we used, since there was no immediate need, we were stable with both diesel generators, is it came through this way and we waited the additional day and a half to get our paper completed before we put it in service.

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Any questions on that?
MR. LOVELESS: This is David Loveless. How would you authorize an emergency temporary modification?
MR. MCKENNEY: Our process that is involved in that involves -- it's considered an immediate threat to the safety or reliability of the plant or involves authorization from the shift manager and the engineering director. So that's within our existing processes.
MR. BROWNING: This is Jeremy Browning. What we're trying to communicate in the prior slide and this slide is the modeling that we did, is assuming that this process that we actually used would be applied to the process, or applied to the applications that we would be talking to you.
So it's what we actually did and it's what we would have done had we had to implement one of those contingencies. That's what we're trying to communicate in these two slides. Which means the installation in the field would have been controlled to the four quarters. There would have been engineering support paperwork unless we declared that we had a safety function that was challenged, which would be the only gate to an emergency. We would invoke paths where

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it says available for use until the process was complete.
MR. KENNEDY: How many other options did you actually start down this path, this implementation process path other options in parallel?
MR. BROWNING: Not in any great detail.
MR. MCKENNEY: We were in this step block, right here, according to that and we had done some of this (indicating).
MR. BROWNING: But what you're going to hopefully see is the work order instructions for installing a Raychem splice, for example. That Raychem splice per order instructions can be translated over into this option. The installation of this component you just changed the nomenclature of where it's going, and the fieldwork could have been done. If we were halfway through option, the one we were doing, it's a matter of cutting cable and redirecting that cable. The work order instructions can come out in our process and use by the craft just in a different locations.
MR. DAPAS: Marc Dapas, the salient point here is that you actually implemented this process and the manner in which it was provided to restored 4160-volt power. You would have used the same process and you're assuming other three contingency success

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paths that you indicated that you could have received --
MR. BROWNING: When we get into the risk -- that's correct.
MR. DAPAS: So I understand where you're going next. I just wanted to make sure I understood that part.
MR. CIRCLE: Just one last question. This is Jeff Circle, again, did you retain those records from the last, from the implementation process considering the restoring power if you needed -- contingencies?
MR. KOWALESKI: Do we have any written records of what we did?
MR. CIRCLE: TLC logs.
MR. MCKENNEY: I do not have that. I have some personal documents for, basically, how we transitioned off from one to the other because part of this is, you know, we have to figure out how we're going to transition from these different options back and forth.
MR. KOWALESKI: The answer is, there's some personal notes that people have, but we don't have any formal --
MR. CIRCLE: Nothing formal.
MR. MCKENNEY: No formal. I'm going to

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circle back around, finish up the -- what we actually installed, which is a demonstrated -- we're calling it a demonstrated success was the Startup 1 source.

So restored power to vital switchgear, the craft was qualified and to do the activities that we're talking about it provided the option tied to either of the vital buses and allowed the diesel generators to be available to feed their respective train while we're installing it.

And it was actually available -- if you look at that block that we talked about in 4.4 days. It was actually energized up to the last breaker. And that was documented in station log for that was when it was available.

The next thing I want to get into is the 3 4160 alternate success paths. And these are things that we talked about were being scoped in parallel while we're installing the demonstrated success.

And the estimated times, if we're going to compare back to what we actually installed on how long it would take to do it. We're going to show you that these are considerably more simple and less involved.

So this first success path would be a simplification or an alternate to the actually installed

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success path. So what we've done here is eliminated the temporary breaker. The temporary breaker provided some additional flexibility, but if we were in a station blackout or loss of an additional diesel -- and we're on page - slide 24 -- it would, so it was basically, run the cable from Startup 1 transformer to the cross tie between the safety buses or the vital buses.

And what that looks like on slide 25 is we have the Startup 1 transformer and we still would have routed it around the area where the damage was, but we would have taken a more direct route.

And so we would have used quite a bit less cable, and we would have tied it to the exact same spot that we used in the actual installed installation.

If you look at this table, this is a comparison between the expedited or success path one and the actual installed and you can see that it's half as much cable, half as many terminations, and we do not have to install temporary breaker, we do not have to do the testing on temporary breaker, the DC supply for the temporary breaker, so there's quite a bit of scope that would have been eliminated by that particular option.

MR. KOWALESKI: This is Joe Kowaleski, to that previous question on cable availability, if you look at that total length of capable plus the next

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option, that total length for both of these two options is 2500 feet cable, 2450 feet of cable. The actually installed one was 3,500 feet of cable. So what we actually did is a thousand feet more cable than if we were doing this option and the next option in parallel.

MR. CLARK: This is Jeff Clark. I just have a question. On the first demonstrated option we had the breaker in here and I'm assuming that provided some safety feature to the bus as well. So did you have protective devices other than the (can't hear) transformer to the bus?

MR. MCKENNEY: The expedited option, or success path one we're calling it here, did not, but it had the upstream protection on the transformer itself.

MR. CLARK: From the transformer --

MR. MCKENNEY: Yeah, on the high side.

MR. CLARK: I understand.

MR. MCKENNEY: The other reason why we installed the breaker was to -- operating the breaker on the high side of the transformer is an Entergy Arkansas function. So by putting the breaker inside we were able to allow operations to have control over that within their own station. So that was one of the key functions of that breaker.

MR. BROWNING: And what we actually did

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was positioning ourselves for a long-term recovery, giving us the maximum operational flexibility. Had we lost a piece of generator, that priority would have completely shifted. We're no longer looking at long-term recovery and operational flexibility, we're looking at how do I connect to that bus in a safe, efficient manner.

MR. DAPAS: This is Marc Dapas. Just a question to make sure I understand. The difference, then, between your success path one and what you actually did to restore is connecting a cable directly to the winding versus via temporary breaker --

MR. MCKENNEY: That's correct.

MR. DAPAS: -- Startup point transformer?

MR. BROWNING: And shorting the path.

MR. DAPAS: And the reason why it's a shorter path, why would you have not exercised the same path you did in the actual restoration? I may have missed the --

MR. BROWNING: The real basis there was that operational flexibility, the time we had and lay down areas for recovery. Where we would have laid that cable for a direct path, would not have afforded us the opportunity to finish the recovery efforts that we knew we needed to do. It would be outside of the area that

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was impacted, but because of where we needed to move material inside our turbine building, we wanted that outside the turbine building altogether for maximum flexibility inside there.

But that's a different decision than I don't have power on one of my safety buses. I'm not thinking about long-term recovery. I'm thinking about power to my safety-related bus.

MR. MITMAN: So, before we leave that one, can we go back two slides, back to slide 24, please. This is Jeff Mitman. The scenario where you'd need immediately the offsite power would be some failure of the vital AC power. Now the largest contributor to that would be a failure of the diesel generators.

MR. MCKENNEY: Right.

MR. MITMAN: It seems like that's what you're built your contingencies on, your success paths on, is failures to the diesels. But we're in a condition where the stator has been dropped, there's extensive damage on 1A1 and 1A2 and I can easily envision a situation where there's damage to the A3 and/or the A4. Not directly from the stator drop itself, but because of problems in the electrical system that has caused failures in the associated electrical distribution system.

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Did you consider any contingencies to reenergize loads that didn't rely on the A3 or the A4?

MR. KOWALESKI: Yeah. The third option, or the fourth option that we'll talk about is one directly, it's a 480-volt power directly, bypassing all 4160-volt switchgear.

MR. MITMAN: So that's the contingency if the failure is other than on the diesel generator?

MR. KOWALESKI: In the event, although the aux building is completely separate building, in relaying protecting the safety buses from damage on the non safety buses. If all that had failed, both diesel generators had failed, and the safety buses were completely unavailable on the 4160-volt, there is a direct path to 480-volt power to the necessary makeup pumps with multiple options that completely bypass the 4160-volt system.

MR. BROWNING: David, let's get you back on track. Let's move to success path two if there's no more questions on success path one.

MR. MCKENNEY: I want to give a little overhead view on page 2, slide 27. This gives you a physical layout and the general area of the train bay where the stator fail. Here is the 2A9 switchgear, which is located on the Unit 2 side. This is a wall

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between the train bay and Unit 2.

These were the route of the cables that went to A1 and also to the vital switchgear. So when -- and also from -- A2 was actually de-energized at that point in the outage. So there's a cable that runs from A2 switchgear and that's what feeds to the A4 vital switchgear.

And I'm going to show where we're going to use this green cable here in a moment.

MR. KOWALESKI: And that end of the switchgear was undamaged?

MR. MCKENNEY: Yeah, this end of the switchgear was undamaged, which is the west side, or to the left. And on the right this side right is where the stator, the main impact was to the switchgear. This side here was not damaged.

MR. MITMAN: Before we leave this slide, what's the source of control power for the 2A9 bus?

MR. HATHCOAT: The source of control power is DC, it's all from the Unit 2 control room. The Unit 2 control room basically has the controls to start the alternate diesel generator and tie it on the. Unit 2 side.

MR. MITMAN: So the source of control power is --

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MR. MCKENNEY: From Unit 2.

MR. MITMAN: -- from Unit 2 and on the DC system?

MR. MCKENNEY: So I'm on slide 28, and what this does is we would -- we're going to hook a cable from -- disconnect a cable from A2 which right here, from A2 and run it through the door into Unit 2 because these are on the same elevation and there's a door, I'll show you an overhead view here in a moment, and splice in approximately a hundred feet of cable and tie it back into 2A901.

So we had to make some very minor -- the termination points were damaged in 2A901. And when we actually, physically repaired them, it took six hours. So it was, the breakers were fine, it's just where the cables terminated.

Also important on this is, you can see that this success path No. 2 is completely independent of success path 1 or what we installed. They use different tie points. The physical location is different. The sources are different.

And this is an overhead view on page -- slide 29. You can see where we disconnected the green cable from A201's cubicle and ran it through the door and it'd make it about this far, so we just had to run

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about a hundred feet of cable.
Of course, that's a hundred feet times seven because we have seven conductors or three parallel paths times three, plus one. And we would have tied it in to the alternate AC switchgear in the back.
MR. DAPAS: Just to make sure I'm following this, can you show me why given our discussion earlier about the ultimate AC, 4160-volt bus the damage associated with that bus did not impact this success path, too? I just wanted to make sure I fully understand.
MR. MCKENNEY: We would have to make some minor repairs in the back of 2A9. I have some photographs here I can show you, but we would have had to make some minor repairs and as I stated, it took six hours to make those for the permanent repairs when we actually did do that.
MR. DAPAS: So what's the timeframe there to assess, if you will, the extent and condition associated with the damage to determine minor repairs and all that's necessary and then the time to implement those repairs were all factored into your timeline for how long it would take you to complete these success paths?
MR. MCKENNEY: Yes. Let me get to the

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next couple slides down and we'll discuss that.
MR. SULLINS: I just wanted to add that while identified early, the tie point on the normal feed to the A4 vital switchgear, we actually used this tie point for a second offsite power feed later in our recovery and the splices were very near where illustrated on this picture.
MR. MCKENNEY: So this is slides 30 and this is talking about the differences between what we actually installed, we're always tying back to that because it demonstrates that we were able to complete these splices and terminations and pulling this cable.
So on the right is what we actually installed. On the left is what would be required to hook up success path No. 2. You can see it's about 700 feet of cable, half as many terminations or splices, 14, and we'd have to make some minor termination point repairs in 2A901. So we can be pulling cable, we could be making up the stress cones or the termination kits while we're repairing the 2A9 switchgear. That could be running in parallel and whatever electrical testing that we felt we needed to do.
MR. KOWALESKI: So the only damage to that switchgear was the connection points on the outside -- output of that breaker. That's all that had to be

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repaired were those connections.
MR. DAPAS: And this is Marc Dapas again. Understand, you're looking at success path 1 or success path 2, right? Not both success paths, correct? You would have had to make a decision to use one or two or both --
MR. KOWALESKI: These could have, and in the event of diesel failure, would have been pursued in parallel.
MR. DAPAS: So getting back to Jeff's question here, factoring that into your timelines, ensuring sufficient cable availability, using the processes that you've described, you're going to be doing that with both of these contingency plans, would that have resulted --
I wanted to understand with the time you assumed to implement each contingency plan does that reflect the recognition that you're pursuing both of these in parallel and did you the right number of staff, you know, that were focused on each one individually, or are you relying on the same staff to make decisions and how did you factor the fact that you would potentially be pursuing two paths at the same time?
MR. KOWALESKI: If you recall back on page 9, there were 45 electricians per shift, so 45

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electricians per shift could easily pursue both of these options. There were 40 engineers per shift to provide support, and 60 operation staff per shift. So there was sufficient resources to be able to pursue both of these paths in parallel.
MR. BROWNING: If you looked at the scope of work that we were planning on implementing on a given day during the outage, it would be comparable work. Actually, it would be significantly less. To implement what we're talking about would be significantly less than what we were already planning on doing during any incident.
MR. DAPAS: The context of the questions I'd offer here, at least I'm not aware of risk assessment's allowed for credit for cable routing here and alternate power supplies, installed equipment and when that equipment failed what redundancy do you have, etc.? So, it's important that we understand clearly the timeline assumptions here when you pointed out in one of your earlier slides that you would have been able to implement one of these contingency plans before you would have seen that a core uncovered.
MR. BROWNING: Yes, sir.
MR. KOWALESKI: And we do have a timeline picture that may help clarify that.

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MR. LOVELESS: Before you leave the -- this is David Loveless. In this particular success path you're talking about accessing two areas that were significantly restricted, at least early on in the event. My understanding from the AIT that the entire switchgear area in Unit 1 was closed off. At some point no one was allowed in there, but then it was very limited when it was. And then on the Unit 2 side --

SPEAKER: This is headquarters we're having trouble hearing you guys. Could you speak close to the mic, please?

Thank you.

MR. LOVELESS: On the Unit 2 side, we're talking with th followup team about some of the work -- or on some of the -- that plus 2 Alpha 1 where they couldn't get in there. They said, no, we've got energized equipment in there, we've got water all over the floor, nobody's going in there. So I would expect to see both of those restrictions somehow.

When did we know that this green cable was accessible and it was undamaged? When did we have Unit 2 side cleared up enough that someone could actually access it?

MR. MCKENNEY: If you look back on slide 29 -- actually, let's go back to this one, slide 27,

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okay? This cable, we actually had access up to this point. The major damage, structural damage, was in this area. So they did put a fence right across here, but this was visibly - was not damaged. So we could get to this area easily. And we actually did do assessments the first day in all this area.

MR. HARRIS: And David, let me see if I can address your question. I believe what you're referring to is at the onset -- immediately after the stator drop event occurred, there were limitations allowing operator access into the Unit 2 area because of the water intrusion and certainly associated with that area.

That was immediately after, and we dealt with that in relation to, you know, recognition of what the condition was for emergency classifications and the danger.

What David is talking about is - would be - would come in a much later in relation to developing a recovery strategy and getting access in this area. So I don't think there's any - these are not mutually exclusive, or these issues are not contradicting each other, but -- because immediately after the accident we did try to restrict operator access to that area, but later on during the recovery phase, we would have been

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able to go in and do these actions.

MR. LOVELESS: I guess my point is that most of risk we're looking at is, at time zero we go into station blackout, and the times for recover that you're talking about aren't from somewhere a couple days later after you stabilize and have been thinking about it while. It's now. You need power now, and you're telling me I'm going to be going into an area that we haven't assessed to determine if it's structurally sound yet and I've got other electricians I'm sending into the area full of water with energized equipment.

So I do see them as overlapping.

MR. HATHCOAT: This is John Hathcoat. At least on the Unit 2 side with emergency class declaration around the 2A1-2A9 bus was a little bit delayed from when the actual explosion occurred. That was due to water on the floor, but after a couple hours, and then about 13:30 is when we actually had the log entry that we were able to assess the back of 2A9 safely.

So it was roughly six hours of being delayed, and we were able to access that back -- and we'd been back there for awhile being able to access the area. So that's just a point of reference.

MR. MCKENNEY: Are there any more

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questions on success path No. 2? And I'd like to move onto success path No. 3 which is on slide 31. This has to do with -- it's a variation of the station blackout connection that we just talked about in success path No. 2.

What that involves there is we connect to the same green cable that we showed on some of those other ones there and we would, instead of connecting to the 2A9 switchgear cubicle, for some we couldn't repair that, and we had this particular option; we could have disconnected a condensate pump, which is non-vital. This is Unit 2, 2A1, Unit 2 switchgear, not the Unit 1. And we would disconnect a condensate pump and connect a temporary cable to it's output breaker.

And, so we'd have to do some minor reconfiguration of the control scheme for the breaker, but we have -- it'd be the same as our load center breakers. So we'd have the scheme well defined, could easily have made the transition over to that.

If you can see from slide 32 here, the route is basically the same, cable splice would be in the same spot, instead of hooking to 2A9 over here, we'd just loop back the cable and hook into this spot, so.

We would run success path 1 and success path 2 or 3 in parallel. We wouldn't do both of these

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because they're -- this tie point on the opposite end here, 409, is a snake. But it does provide us an option if for some reason we couldn't get the 2A9 switchgear repaired or if -- so we could have another place to tie to get power.

It does provide some nice options also that -- 2A9 also -- and this cable from 2A2 to the -- is always energized. So this cable, which is shown in red here, back on slide 31, from 2A2 to 2A904, that remained energized through the entire event.

MR. CIRCLE: You mean 2A1?

MR. MCKENNEY: 2A1, thank you.

MR. CIRCLE: See, I was paying attention. But I do have one question. This is Jeff Circle again. You mentioned success paths 1 and 2 might be done in parallel?

MR. MCKENNEY: Or 1 and 3.

MR. CIRCLE: 1 and 3?

MR. MCKENNEY: 1 and 2 or 1 and 3, but not 2 and 3.

MR. CIRCLE: So we needed some clarification.

MR. MCKENNEY: Yes. That's what that -- because 3 is a variation of 2.

As you can see, it's basically, the scope

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is the same, pretty much, as what we did on the alternate C breaker, which is 901, with the difference being where we wouldn't have to repair the 901 breakers. We would have to do some minor interlock defeats and reconfigurations so the breaker would now think that it had a condensate pump hooked to the other end.

In addition to that, we were also looking at other -- and these were three primary methods. We were also looking at a unit back feed in case Startup 1 transformer was unavailable, which we'd back feed through our main transformers, hook to the unit aux, we'd basically hook up the same way as we did the starter transformer. Just another source to get power from the switchyard into the plant.

We also had a portable diesel generator that was being shipped in that we could have, basically 480-volt, the step-up transformer, that could have provided us 480-volt power.

MR. DAPAS: Can you elaborate -- this is Marc Dapas. You have a slide there that would indicate these additional success paths were considered and scoped. I'd like to hear, maybe Jeremy, you can provide a little more context. Where did this occur, was it conceptual here or how far along were you in that process scenario?

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And I'm trying to differentiate, quite frankly, after the fact -- we could have pursue this success path versus what was actually being considered by the staff that was involved in responding to the event?

MR. BROWNING: The three that we're discussing with you are the three that we are modeling because they were the three primary success paths that we were considering; however, we did order the diesel generator. The diesel generator showed up to the site within 48 hours of the event occurring.

The back feed option is something that we have done before, had the station back feeding off of -- so it's not a concept, it's something we've actually done, but we weren't actually pursuing that because we had stable transformers at that time.

And the restoration of A1 non-vital to Startup 2, again, we actually took an approach that we brought in Startup 2 during the recovery and powered it up in the plant. But at the time of the event, those were more concepts. We knew we could do them, but we really weren't putting a lot of effort into it, other than we were ordering the materials and resources we needed to do it.

MR. DAPAS: And the context of my

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questions here -- I think you've heard the general theme of questioning. What was the understanding of the operators, what's involved in going out and verifying what the plant conditions are, what are the equipment availabilities so we can pursue these contingency options.

What -- there's a lot going on here, obviously, in response to this event, right? You had flooding as a result of the fire main being damaged, you had equipment that was damaged and understanding the full extent of that equipment damage to determine whether these paths were viable here, and what you need to do to ensure that the effort expended is going to result in the desired outcome because you fully scoped out the condition. That's what I really need to understand here.

MR. MCKENNEY: To give you little context on what was scoped --

MR. JAMES: Before we answer that, let's make sure we're talking about the options that you're interested in, Marc. I think you're interested in the three that we discussed in detail; is that correct?

MR. DAPAS: Well, the three that you offer, the next step is to credit these and the risk assessment, saying these were viable success paths,

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therefore, NRC where you've assumed as a result of diesel failure here's where you end up. You're planning to --

MR. JAMES: Because I think Jeremy was answering that these three on -- these additional ones, so we need to make clear that we're responding to the three that you asked, which were our three success paths that we proposed.

MR. BROWNING: So, have we answered your question?

MR. DAPAS: After we've completed the full discussion here today, I'll be able to answer.

MR. BROWNING: I wasn't sure we did.

MR. DAPAS: I think we're in the -- at least I'm in absorb mode right now and I'll need to take a little bit of time to make sure all the questions I have are asked. Right now we're going on.

MR. MCKENNEY: That's a good segue into slide 35.

MR. WILLOUGHBY: This is Leonard Willoughby. I do have a question.

MR. MCKENNEY: Yes.

MR. WILLOUGHBY: There was other things going on in the plant at the time. Right now we're just focusing on the recovery of this area, but you had some

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other things going on in the plant that you also had to expend resources to address, such as the steam generator seal and stuff -- and how is that factored into all your decision making process and all those other items that you need to look at because there was a lot of things going on over all?

MR. MCKENNEY: So different disciplines in a lot of those cases, right, so this is mostly electrical so I've got mechanical disciplines that are working on seals and mechanics, and this is heavy electrical here, right?

MR. WILLOUGHBY: But doesn't one person -- who makes the final decision? It all rolls up into one.

MR. BROWNING: Just from my observation, from the EOF to the TSC to the implementing organization that day, those decisions are being made by an emergency director. And that emergency director is assessing safety functions. So when we expend resources, we would have put our resources on a safety function that was the most challenging.

If the assumption is two diesel generators aren't running and they need them to be running, then based on his understanding of safety functions, the trigger process driven. He goes through

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a process that comes out, electrical power is my top priority and his resources.

He has to make decisions based on facts, but a flowchart gets him to the end. And that's where he would -- in this case we did have some challenges with our seals, but those seals, even if they would have completely failed, the mechanisms that would have allowed that -- inventory could have been a challenge, but if electrical is gone, the flowchart is going to say priority is electrical, inventory is No. 2. As we continue to watch that inventory because of the rate of loss.

So I don't know if I'm answering your question, but it's process driven against safety functions and the information he has will drive him to the that conclusion.

MR. WILLOUGHBY: You answered my question.

MR. BROWNING: I just wanted to make sure.

MR. MCKENNEY: I want to summarize the different success paths in this slide. They're simple design concept and simple to implement. Craft personnel were qualified and scheduled to perform the same type activities with the circ pump cable replacement, so they

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had the equipment on site, personnel on site that knew how to do that work. It's activities that we do on a regular basis even with it online maintenance work.

Cables were routed away from the damaged area. It's important to know that the success paths, other than 2 and 3, are spatially and electrically independent of each other. They could be implemented in parallel in sufficient time. Could have been done -- we work these sequentially and we'll show that later in the presentation.

And all three of the success paths we presented are less complex than what we actually installed in 4.4 days.

MR. DAPAS: This is Marc Dapas. I just feel compelled to react to a simple design concepts. You're relying on contingency plans here that involve running cable runs here to establish power to 4160-volt safeguard buses is not where you want to be.

So, I understand you're going through and explaining how you would have restored power. But this is -- that's not where you want to be. You want to be in a situation where you're relying on installed equipment here versus these contingency plans, cable runs and terminated here and splicing. That's not the desired approach here to be able to insure plant safety,

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right?
MR. KOWALESKI: Absolutely. The fact that the event occurred is unacceptable. The damage that occurred to the plant is unacceptable. But in determining the safety significance of that, we have to look at what would be a realistic response to it. And this is a realistic response to it.
MR. CIRCLE: This is Jeff Circle. Just keep in mind what we're talking about here is a station blackout. These success paths are paths for mitigation of a station blackout, so conditions are not typical of normal outage. And it's not typical of normal outage activities, so there's going to be a lot of stress involved.
MR. KOWALESKI: Yes, and when you look the timelines you'll see there is a substantial time margin. I would point out, though, that work in the Startup 1 area was done just as it would have been, the environmental conditions, that the work done was the same as a station blackout, the work done the Unit 2 area around the alternate ACD generator switchgear would have been the same as it was during the time we implemented would have been the same as a station blackout because that is the opposite unit which had different power sources.

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So there's a consideration that the actual installation that was done had a lot of similarities of plant conditions to conditions they would have seen during a station blackout.
MR. DAPAS: I appreciate you're pointing out there this is not significantly different from the actual response you invoked here, right, with how you established power to 4160-volt. It's not just modeling here, you are extrapolating, right, from what you actually ended up doing with timelines that reflect what occurred, right?
MR. KOWALESKI: That's correct.
MR. DAPAS: So I appreciate that distinction. I think what you're hearing some of the questions here is making sure we understand how you factor various things here, and the station blackout scenario is different than both diesel's are running, continuing of power, the safeguard's buses here, you're in a station blackout and you've indicated you would be having different cable, you would be considering the shorter length. That would be your primary focus here from a safety function and I understand that.
But also, with that shift in focus is, there's a little bit different operating environment here, so just how do you account for that?

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MR. KOWALESKI: Yes and we will explain how we account for that when we cover that model.
MR. CLARK: This is Jeff Clark. I have one more technical question that I didn't ask before. I thought you might covered it in some of the other diagrams, but going back to success path No. 1 and you had the temporary breaker with the DC control power. Was that just a local operating breaker, or did you have auxiliary operations in control?
MR. MCKENNEY: It was local operating, but we ran a cable from the Startup transformer DC and ran it over to the breaker to give it DC power.
MR. CLARK: Okay. I understand. Thank you.
MR. MITMAN: Jeff Mitman. On slide 35, I want to explore some of your characterization a little bit. The first two bullets, you talk about simple design and simple to implement. First of all, it's my understanding success paths 1, 2, 3, and 4 you haven't completed the design today; is that is correct?
MR. MCKENNEY: We did not implement these designs because we didn't have to.
MR. MITMAN: Did you complete the designs?
MR. MCKENNEY: We scoped the design, we

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did not complete a design.
MR. MITMAN: So the designs are not complete. So a year and some months later the designs are not finished. All right. Second --
MR. KENNEDY: Hey, Jeff, hold on, just for clarification. Did you intend to complete them?
MR. MCKENNEY: No.
MR. MITMAN: What I'm trying to get at is, conceptually they may be simple, but they're not five minutes worth of work, okay? So the characterization of them as being simple designs, I think, in risk space is -- simple has a certain meaning in risk space, you know, typically simple is something that an operator can do in five minutes. These are not five-minute activities. These are engineering activities that will take a team of engineers hours to complete. The implementation of these are not activities that are done in five minutes.
It took your over four days to implement what you wanted with teams of electricians and operators and others to complete the work. So, I understand that they're not rocket science, but nonetheless, in risk space, their complicated activities that take a lot of checks on them and a lot of people verifying what's been done and a lot of care in getting them implemented.

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Is my understanding of that correct?
MR. MCKENNEY: The slide is intended from an engineering and installation standpoint that it's simple. Now as far as the time, that's a different concept for engineering.
MR. KENNEDY: I would offer that "simple" probably is not the right word to choose for this quorum.
MR. DAPAS: I thought that was evident when I made my earlier comment. I don't want to belabor the point here. I think the role I'll offer here of the NRC staff is to fully understand the assumptions here you've made, how you feel the success paths should be credited, and you need to be asking questions that will further illuminate, if you will, how you factored this into your overall risk assessment here.
We'll have an opportunity to engage here and determine, based on our independent review, an assessment; how much credit we think is appropriate considering uncertainties, etc. The vein of the questions really need to get to a full understanding of your conclusions and the basis for those.
So let's proceed, please.
MR. SULLINS: Okay. We'll move to our success path 4. This is Gary Sullins again, and we are

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on slide 36. We understand that in the present risk assessment, inventory control considers gravity feed from a borated water storage tank that the assumption that there's no electrical power available.
In our loss of decay heat removal procedure and strategy there actually are six prescribed methods for make up. One has been analyzed, which is passive gravity feed. Three involve 4160-volt power. That there are two others that rely on 480-volt driven pumps for the mode of force. And so we'll be discussing one of those alternatives.
The success path that we'll be discussing involves use of our borated water recirc pump. And our loss of decay heat removal procedure, we detailed guidance to align P-66 borated water recirc pump with a suction supply from either our BWST or our spent fuel pool for makeup to the RCS.
I should also note that this pump also serves as makeup source for spent fuel pool, and given an assumed station blackout, we are interested in restoring this capability for that purpose as well.
This is a success path that was not evaluated at that time of that event. And the basis for that is we were setting priorities based on the conditions that we had. After the stator drop event we

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had four of our six makeup sources available. And so this was not classified as a need or scoped at that time.
But given the assumption of a station blackout, we would from four, actually more than that, prevent to zero make up sources, so with an extended blackout we would recognize that inventory loss would become a concern, and we would be pursuing options through our support staff for that.
Any questions on the concept?
MR. LOVELESS: Just one point of clarification. This David Loveless. Unless I'm missing something, this is what in risk we would call more of a delaying action, not a success path in and of itself. It would give you more time to get a success path in place. Am I hearing that right because we're going to be boiling in the core and the spent fuel pool. We're not going to be a stable place.
MR. SULLINS: That's the first consideration of it. Much like our spent fuel pool, it can be used for longtime cooling, but that involves getting energy out of the reactor building, consideration of the venting, thing of that nature.
MR. LOVELESS: Okay.
MR. SULLINS: And to support this

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function we would, again, use a temporary modification. This time using the London Line power that we referred to earlier and David will explain that for you.
MR. MCKENNEY: Okay we're on slide 38. This particular one we're showing a disconnect switch S-28 on this upper left-hand portion of your diagram here.
This is actually 600 amp, 480-volt disconnect that's located in the south end of the turbine building, very remote from where the stator dropped. And this is the disconnect we actually used for restorations of our non-vital load centers post event. So this is -- and this is fed from the London Line, which is our yard power, which is -- it was not in the section where the stator dropped. So it wasn't impacted by the stator drop.
So what this success path involves is running a cable, 480-volt cable, from the disconnect and tying directly to the B51 bus, which is the motor control, 480-volt motor control center, it's in our aux building. It's also located away from the stator drop area. And then we take from a spare breaker off of B51 and feed B21, which is a non-vital. And these motor control centers, I'll show you in a photograph here in a minute, are about 18 inches apart.

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This is very common type of activity that we do during outages, run temporary power. We've actually used this in the opposite direction where we fed B21 power to B51 to supply the spent fuel pool pump when we had bus outages on the red train AC power during refuelling outages.

What this does is it brings 480-volt to B51 which gives your battery charger back. So you would be able to maintain your red DC. Also feeds the inverter, spent fuel pump, instrument AC, and gets us over here to B21 where it would feed our borated water storage pump or -- excuse me, borated water pump, which is the pump Gary talked about earlier.

MR. LOVELESS: And 600 amps is enough to provide for all those loads?

MR. MCKENNEY: Yes. The largest load associated with that is the battery charger, and it has a 150-amp breaker, but it's a hundred-amp load. So there'd be sufficient loads for that.

This is overhead view of the cable routing. The stator drop is off the page at the top, so this is in the very far south end, run a cable up through a door, through another door, and B51 is about 200 feet of cable. And then we run a jumper from 51 to 21. You see the relative location of those two.

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A photograph of the S-28 disconnect switch. And this is in the room, this is B51. Here is where we would terminate the cables behind these two doors here, and you can see the relative location between 51 and 21. And we would run the jumper cable from one spare breaker to another and we would be able to power the borated water recirc pump.

So I'm hesitant to put this slide up there when it has "simple" on it --

(Laughter)

-- but it is simple, I mean, from a construction aspect.

MR. BROWNING: Dave, did you mention that we actually performed the jumper between those to buses every other outage?

MR. MCKENNEY: Yeah, when we do those bus outages, we run the jumper between every other refuel outage, depending on which train outage we're in.

MR. BROWNING: And understanding poor choice of words, we've got that feedback. What we're trying to communicate is this is work that we would typically do and implement without a lot of challenges to it's being successful.

MR. MCKENNEY: So it's typical of work we do during outages. It wasn't affected by the event, and

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it was located remotely from where the event happened, and it's independent of the 4160-volt path. And it doesn't have any relationship between the 4160-volt side.

And if for some reason that wasn't available, we could have tied straight on top of the contact here. There's less of the variations you can do on 480-volt side that could accomplish this in the same timeframe. And we estimated this would take 20 hours to implement. And that includes some scoping time for engineering to figure out exactly what to do because the actual electricians I talked to said they could have it done in less than a shift.

MR. WILLOUGHBY: I do have one question. You mention that -- this is Leonard Willoughby. You mentioned that you do this every other outage or every outage. How long does it normally take you?

MR. MCKENNEY: Well, we have the, you know, the papers all are proof for this, it's a repetitive kind of task, right, so, it we actually run -- during outages we run a, do a conduit between -- that we wouldn't necessarily do, and in usually takes us a shift to install, 12 hours.

MR. LOVELESS: This is David Loveless. What you're talking about though is just what's labeled

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as temporary cable B that you do every outage. You don't connect to the --

MR. MCKENNEY: We do not connect to the London Line.

MR. SULLINS: The 480-volt power that Mr. McKenney described also supports our other two makeup sources that don't rely on 4160-volt power; the spent fuel pool cooling pump spent fuel pool cooling pump, P-40 Alpha, it also sets us up for gravity feed capability. Our capability for the reactor building would be through the reactor building purge system. The inboard purge isolation dampers rely on red DC power and instrument air, both of which were available to us, or would be available to us with N2 supplying instrument air and this temporary mod powering our DC bus.

The last item on this slide gives urgency to doing something with 480-volt and that is to preserve our indication.

If we were to experience a station blackout, it would be a priority, not as high as restoring the ultimate heat sink, but to get some power to our battery chargers before our batteries are depleted. And this concept that was presented to -- in your meeting today was -- I looked at this from the perspective of, I'm in the TSC, what are our priorities?

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Number one is recovering vital 4160-volt, the diesels, and ultimate source. Number two is keeping the DC so we can see what's going on in the reactor building, and that would prompt some time of power to the battery charger. Number three, we're without makeup capability, we have six methods. They don't all rely on 4160-volt power, what can you do with that? Given those priorities, this is what the engineers -- basically this is an exercise that they would be the TSC engineer, I'm the TSC manager with those priorities in very short order you can -- this is what I would propose.

The next slides illustrates --

MR. MITMAN: Jeff Mitman. Before we go on, the condition the plant's in at this point is the canal, the cavity is flooded. Now the normal source of water to flood the cavity is normally the borated water storage tank. It's my understanding that that's, in fact, what had happened. You used the water in the borated water storage tank to fill the cavity.

Is my understanding correct?

MR. SULLINS: Yes, that is correct. We had approximately four feet in BWST, it's 9,700 gallons per foot plus some few more.

MR. MITMAN: So approximately 30 to 40,000 gallons. If you'd gone to using the borated

water transfer pump at, say, a nominal flow rate of a hundred gallons a minute, that would give you something like 40 minutes worth of water.

Again, is my understanding correct?

MR. SULLINS: From the normal alignment that is correct. We did not describe the details of this strategy, but I would direct that we set up our makeup capability from our B5B security procedure for BWST makeup and we have multiple sources, clean water sources in our yard, and that would provide a makeup capability to our BWST.

MR. MITMAN: When you say clean water sources, do you mean non-borated water sources?

MR. SULLINS: Yes, that's correct.

MR. MITMAN: And so, you've got an analysis you've contemplated putting non-borated water into the primary system?

MR. SULLINS: Not directly into the RCS. The strategy, provided we needed this for a longer period of time, the P-66 provides makeup to spent fuel pool or directly to the RCS.

So the sequence I would follow is I would first use the borated water in the BWST as makeup to the RCS for boil off. Then I would transfer using the same lost decay heat removal procedure available from

inventory from the spent fuel pool. I would then make up to the spent fuel pool and you have mixing, past reactor engineering -- since we had not reloaded with fresh fuel to maintain one and a half percent shutdown margin, we need approximately -- just slightly under 400 PPM boron in the RCS. So we would not go directly without --

MR. KOWALESKI: But you're not leaking the boron? You're evaporating -- the boron stays in a solution, so you're replacing inventory and your boron is still there?

MR. SULLINS: That's right. But there is consideration for mixing and so the methodology I prescribed for you would be the course that I would follow.

MR. BROWNING: I wanted to be clear. The capacity is 100 gallons a minute, the need was 50 gallons a minute.

MR. MITMAN: And the operators knew that?

MR. SULLINS: Yes. We post required makeup capacities.

MR. MITMAN: And, of course, you had some excess capacity in the spent fuel pool that you could also use if the engineering judgment gets to that point. You also talked about, on slide 43, the ability to gravity feed.

MR. SULLINS: Yes, sir.

MR. MITMAN: Now, my understanding is with four feet of water in the BWST, the water level in the BWST is lower than the water level in the cavity, and therefore if you try establish gravity feed, you'll try and won't succeed, but you'll try and refill the BWST. So, I'm surprised -- could you explain a little bit about what you mean by that bullet about gravity feed?

MR. SULLINS: Certainly. We would need to make up the BWST again without borated water to our procedurally required -- a value greater than 21 feet, and then this is the last contingency because you are in that case relying on the boil-off effect and you might have some mixing concerns, but it does provide that capability.

And that was really all I wanted to make of that.

MR. MITMAN: And gravity feed, if I remember correctly, is describe in your loss of decay heat removal procedures, correct?

MR. SULLINS: That's correct. That's where the 21-feet limit is supplied.

MR. BROWNING: The makeup to the BWST is proceduralized, we do not have to create that makeup

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source. We'd have to think of it.
MR. SULLINS: That answer your question? We've had a number of questions related to timing and the fact that -- we appreciate that there are many things going on in our facility and that we would have to establish priorities, but the most significant factor for risk from our perspective is the passive cooling capacity that existed in the fuel transfer canal. That provide for us an available inventory of 4.8 days.
What this slide illustrates is the time required for each of our four success paths relative to the time available.
And we appreciate the comments regarding parallel paths for success path 1 and success paths 2 or 3. What I'd like to point out here, if success path 1 were our first priority then we would begin that activity with plans to commence the backup if there's a problem with our offsite power source from Startup 1, that we pursue parallel paths. It's illustrated in a simple manner here, but what's key is the time available and that -- what we've modeled, we've taken a reflective look of how do we do business, and what would we reasonably do.
And if we're in the TSC and we can't get either of our diesel's back, we will pursue multiple

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options -- if there's a problem, if that Startup transformer, that first priority, we want a back up to go to. And Mr. McKenney's established that that was physically viable, and what this illustrates is that we had the time to execute that.
Any questions?
SPEAKER FROM PHONE: Yeah, this is Sunil Weerakkody at headquarters. I have a question on slide 44.
MR. SULLINS: Okay.
SPEAKER: Just a clarification, I know you're comparing the success path for the different success options for the 4.4 days after the core uncovery then you have the time to start boiling which is about 12 hours. So am I understanding this correct that given any of these success paths you would boil the core, start boiling the core or is that also?
MR. SULLINS: In the unlikely event of a station blackout where we could not recover diesel, we predict that there would be core boiling in that recovery.
SPEAKER: Again, this is something that I'm reflecting on, so when I call this a success path, it's a success path with core boiling where you have started core boil off, but you have prevent core damage?

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MR. SULLINS: Yes, sir, that's correct.
SPEAKER: Now, given that you'll be having some boil off, right, where does the steam go? And would that affect any of those follow-up actions that you count on in the success path?
MR. SULLINS: That's a good question. Once the core reached the boiling condition that would prohibit access to the reactor building and we have factored that in to what we credit for actions.
SPEAKER: Thank you.
MR. SULLINS: Other questions?
MR. KENNEDY: On the timeline, does it include everything today we've talked about today with respect to the engineering work that would be done, the laying out of cables and breakers, does it take into account the delay in access to inspecting the switchgear and the breakers, you know, initially after the event? You know, pretty much all the questions that were asked.
MR. KOWALESKI: Kriss, it's based on what we actually did. So we actually installed this in 4.4 days. So all those access issues and all those impact were part of that. And then what we looked at is what scope was eliminated because these didn't include all the breakers, relays and additional routing and additional splices. It essentially prorated that

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estimate down.
But you can see that there's sufficient margin that if there was 12 hours of delay, there's still substantial margin time to complete these options.
MR. KENNEDY: Do you think that would also bound -- implementing these actions, if you had a station blackout -- would there be any complications that would be created by the fact that you were doing these activities in a station blackout plus the conditions that you have actually had?
MR. BROWNING: That's correct. And that's what Joe was trying to explain earlier. If you looked at the turbines and look where some of these cables would be routed -- we routed, we spliced around Startup 3, it would be no different than a blackout. The environment we would have been working in were very similar environments to actually work in, where these splices were occurring.
MR. MCKENNEY: They were in the turbine building, they weren't anywhere that had any radiological concerns.
MR. KENNEDY: -- lighting access --
MR. BROWNING: Actual conditions were that of a blackout on Unit 1.
MR. DAPAS: This is Marc Dapas, follow

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up. I have a question, and I don't know if this is a significant time contributor, but I think he acknowledged that if you lost the diesel you'd have to understand why and was it the result of a faulty bus here, and what testing you need to do before you go and power that bus via your alternate cable routing associated with your success paths. So there's some of our time associated with that, right? Is that factored in?

MR. BROWNING: That would be a correct statement.

MR. SULLINS: Let me take just a moment if I could, Jeremy. We have clear distinction through our alarms for the probable cause of loss of the diesel. If we have a switchgear lockout, then we know we've got a problem with the switchgear itself and the conditions that caused the diesel itself to lockout would point toward a problem with the diesel alone. So we do have good indications and alarms to direct us to the cause.

MR. MITMAN: This is Jeff Mitman. How would the fact that you don't have a train B battery affect this? Because without the train B battery, you don't have some of your indications, some of your alarms.

MR. SULLINS: Okay. You're referring to

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our initial condition with the D06 battery disconnect?

MR. MITMAN: Correct.

MR. SULLINS: The affect would be that, if we had the station blackout and we're having trouble starting the No. 2 diesel then we would address that DC power source on recovery, the No. 2 diesel. Beyond that, it's one additional operator action is how I would assess it.

MR. BROWNING: I don't know that we actually answered the question. We had a 480-volt buses cross tied, so we did have DC power. We didn't have the battery connected, but we did have DC power.

MR. MITMAN: But in the scenario we're exploring is the station blackout, and with a station blackout there is no battery on the train B DC power. And so when we start talking about knowing, you know, we'll have lockouts, we'll see the lockouts in the control room, we'll know what's going on, whether we've got a lockout or whether we've got a diesel problem, I'm just trying to explore the impacts of what the control room would know if, in the middle of a station blackout, there's also minus the train Bravo DC power?

MR. SULLINS: We are getting quite technical, but I'll try to answer that question. At the time of the event, the DC power on the green side

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depended on the 480-volt on the red side. And when the non-vital sources went away, the No. 1 diesel started using it's battery and then provided DC power to the green side.

So the sequence I believe we're talking about is the No. 1 diesel fails to start and now we're in a blackout. So in terms of assessing conditions of our green train switchgear, it's not been exposed to -- we would treat it as functional, but that we haven't given the diesel the opportunity to tie to it.

MR. CIRCLE: Would you have considered PDG 2 operable under those conditions? Because you wouldn't have any indication of a problem at that point.

MR. SULLINS: We would know that it's not got control power, and we would consider it operable and work toward establishing control power to it for its operation. In our station blackout procedure we're directed to use the EDG procedure and restore the EDG and that's where we --

MR. DAPAS: If it doesn't have control power, it's not functional.

MR. SULLINS: Yes.

MR. DAPAS: So you say you consider it operable. If you don't have control power to that diesel, it's not available.

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MR. SULLINS: Yes, thank you for the clarification Mr. Dapas. What I'm saying is we don't consider it damaged or suspect. And I thought that -- I misunderstood the question.

MR. DAPAS: But that diesel wouldn't be available because you don't have control power?

MR. SULLINS: Absolutely.

MR. DAPAS: You learned that when you went to start the diesel. You didn't otherwise recognize it as having lost diesel 1?

MR. SULLINS: And just to directly answer your question, we've not considered the diesel operative.

MR. HARRIS: So -- this is Richard Harris. There is a dependency on the No. 1 diesel. That was accounted for in the unit -- in our modeling, the ANO modeling.

MR. SULLINS: Does that answer your question, Mr. Mitman?

MR. MITMAN: I think we're getting there. One of the questions that was asked was, if you have a lockout of, say, the A3 bus, okay, now there's a fault on the A3 bus. It's not what happened that day, but we're ahead of ourselves in our risk analysis, our consequence analysis, but if we do have a fault of the

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A3 bus and you do have a lockout, now, do you know you have a lockout because you've got DC power on that division. But you don't have DC power on the other division and so you don't know what the condition of the other bus is. And now you don't have the DC power that you need to start the train -- the train B diesel, you don't have DC power on it, and half the plant, half the indication, half the alarms, half the annunciators are not working because they don't have DC power.

MR. HARRIS: Jeff, this is Richard Harris. Let me see if I can address that from the perspective of analysis. When you look at the switchgear in the lockout, there is a probability of failure associated with that. When you look at overall risk of diesel failure, then you look at if it fails to start, fails to run, you're looking at support systems, which would be the air supply, the surface water, you're looking at fuel.

So all of that rolls into the diesel ability to run and then probability of failure. The switchgear is only a small part of that failure. It should be included, but I would move that it's not a significant impact on risk in relation to the diesel --

MR. CIRCLE: For the base case it wouldn't be, but for this particular case this

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configuration is very sensitive. Because in this case you're feeding the B train DC from an A train charger. You've disconnected the B train battery. So anything that happens on switchgear A3 is going to have a big impact.

MR. HARRIS: You're right, the consequences would be significant; however, the probability is not significant.

MR. CIRCLE: I don't quite believe that, but you can go on.

MR. SULLINS: The question was related to the operator response. And where he had time to respond and that was implemented, factored into our strategies in our recovery. We operated for weeks with diesels in pull-to-lock with operator control of starting the diesel, since it was not necessary to automatically to tie onto the bus with a blind condition, we wouldn't go blindly close in the DC breaker, but you would go toward a controlled restoration.

This is first time presented with the scenario, but I would predict that we would do a controlled restoration where loads are opened up and then you first energize the bus, and then in a controlled manner recover control power to the diesel.

MR. BROWNING: I'm thinking the question

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is would we start pursuing these success paths, and what I'm trying to assure you of, I personally would not have to know if I had a damaged bus or a damaged diesel. I would be asking my TSE and my EOF what are we doing to establish a connection from offsite to onsite.

Now before we land that lead and turn it on, I would want to know the condition of that bus and I know my staff would want to know. But what we're trying to communicate is we didn't wait. We knew we had diesels running, we knew we had to get offsite power, we immediately started assessing the condition of the plant, we immediately started implementing our plan in parallel with the contingencies, and all I'm telling you is if that diesel went away, whether is was the bus that drove it offline, DC that took it offline, or a support system, these guys would have implemented one of those contingency plans.

But before we energized it, clearly, we would have understood the condition of that plant.

MR. CIRCLE: Right. And we don't doubt it. We're just looking at the impact and trying to assess the impact. As far as the actions are concerned, we know that you would do something.

MR. DAPAS: What I've also heard, this is Marc Dapas, that your timeline accounts for the fact

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that you have to ensure that the buses in this condition where you could power the feed successfully, and that's accounted for in the timeline.

MR. BROWNING: Yes, sir. We're running cables in parallel, we're splicing in parallel, we're accessing what it is that happened.

MR. MCKENNEY: When we put Startup 1, the path that we put in service, so we did testing on that transformer and that was part of the 4.4 days, right? So we went through and made sure that the health of Startup 1 was intact before we energized that transformer.

MR. DAPAS: I do think the line of question was we have train A DC power cross connected to train B and it impacts control power to a diesel which then gets to the probability that you could have lost that diesel, you know, it's not a normal electrical lineup here, right, for providing full power to the diesel source. However, the questions remains and what we're trying to understand is that is there any additional element there and how did you factor that into your analysis?

MR. SULLINS: I do want to assure that the questions are adequately answered. Appreciate the question.

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To summarize, our technical presentation of the success paths, the key item, I guess, is confidence in the success of these the time margin, 4.8 days. The second factor is the substantial resources available for response, as we've discussed earlier, we would have the support structure of an emergency response organization setting priorities and supporting operations and maintenance. We have straight forward installations for which our people were trained and it's consistent with their outage responsibilities.

The defense in depth aspect is important to me. The fact that we had available to us parallel paths for 4160 and available to us an alternate diverse means for RCS makeup.

And then lastly, the demonstrated success with what we did with the full package with the breaker still within the allowed 4.8 days.

Any questions for David?

MR. KENNEDY: I would propose that we take a break at this point. We've been going for about two and a half hours. Maybe take a ten-minute break before we get into the really good stuff and interesting stuff which is the risk significance. It's 3:31 central, if we could be back at 3:41 central and restart. The bathrooms are down out the door to the

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left.

(Break taken from 3:31 p m. to 3:46 p m.)

MR. WERNER: Operator, are you on the line?

OPERATOR SYLVIA: Yes, sir, I'm on the line. Just opened up all the lines.

MR. WERNER: All right. We're ready to restart.

OPERATOR SYLVIA: You may begin.

MR. KOWALESKI: Before Richard goes, this is Joe Kowaleski, we'll provide a written timeline for how to safely assess the condition of the bus as input.

MR. MITMAN: Thank you.

MR. SULLINS: This is Gary Sullins. A point of clarification, we had questions regarding operation of our No. 2 diesel for station blackout and the question was related to operability. We would not consider the diesel operable without DC power; however, we have procedures for starting the diesel without DC power and are trained on those procedures, so that start capability exists for us.

MR. CIRCLE: This is Jeff Circle. Just to clarify that question is, actually, what would be the concern if you restore DC power once you start the diesel and not knowing how diesel 2 had failed?

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Let's say you had failure in diesel 1 or some fault or something that blacked out the A3 bus. Now if diesel 2 failed along with diesel 1, there's a chance that they might not have picked up the electrical configuration which was responsible for diesel 2 failing, would they be that quick to restart diesel 2 given there state of knowledge?

That's the question that we asked, actually.

MR. SULLINS: Make sure I understand the question. You have diesel 2 operating with DC control power provided from a red train.

MR. MITMAN: Right.

MR. SULLINS: And if diesel 2 fails --

MR. MITMAN: If diesel 1 fails. If something on -- I guess red train is your train A, I'm having a little trouble with the color designations. If diesel on train A, diesel 1 fails or something happens to the switchgear --

MR. SULLINS: Okay.

MR. MITMAN: Then power is going to be lost in DC control power, and power is going to be lost to A4 and force the start of diesel2, but diesel 2 would not start. So you'll have a situation where diesel 1 would lockout for some reason. Diesel 2 wouldn't start.

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And it may not be apparent to the watch what's going on at that time.

So, would they be quick to restore -- let's say they restore DC power and manage to get diesel 2 started, would they be quick to start diesel 2, not knowing if there was some electrical fault that failed it in the first place?

MR. SULLINS: MR circle, now that I understand the question, what I'd like to do is to give it some thought and then come back to it later so we can proceed.

MR. CIRCLE: That's perfectly fine.

MR. HARRIS: Okay. Let's get started on the significant termination discussion. My name again is Richard Harris and I am the Manager of Emergency Planning at ANO, and you might ask yourself why is the Manager of Emergency Planning talking to you about risk significance. Previous before assuming the position of emergency planning, I was a risk analyst for ANO. I've also previously held an operating license on Unit 1, but more importantly, Jason Hall, our PRA engineer, is in the back of the here, so we may call on him if you have any questions, because he actually performed the analysis, he may be able to answer any specific questions, but we did have a group of PRA engineers that

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could pull together to go through the analysis and provide the results that we'll talk about today.

The main point that I think we should get out of the previous discussion from David and Gary is that when you look at the timeline for the available time to core uncovery, and you look at the actual time that it took us to restore power to Startup 1, we restored power before our estimated time to core uncovery and that's a fact.

So when you consider that fact then you have to acknowledge that the probability of failure restoring off that power is something less than one.

What we want to do in addition to that discussion is talk about the success paths that Gary and David outlined and how we considered those in our risk assessment, and the methodologies that we looked at in relation to this particular issue.

So our key objective that I think we want to come away is that we want to insure that we have a realistic estimate of risk using the best available information that we have.

At the end of the presentation, I will provide and discuss real briefly the results that we derived independently for ANO.

So, what we started with was the event

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tree model that provided to us, and we reviewed that model to understand the method used and the results that were obtained. We didn't have the complete model that the NRC utilized, so we were somewhat restricted in our review and our analysis on the information that was available.

So, you know, at the end of day, whenever we go back and whenever you guys go back and look at the information provided today, you'll be able to take this information and use it in your full PRA analysis.

The assumption relating to 4160-volt power, it's currently in the model and if you look at event tree, what I'm talking about is this branch here and also associated with DHR, mainly because there are some assumptions in the DHR cut sets that are driven by a loss of power. We believe that the assumptions are not realistic simply from the fact that we did recover onsite power in the available time.

Again, this is the event tree that we just looked at.

On slide 50, one of the things that we were challenged with, and I believe it's one of the things the NRC was challenged with as well, is what method do you use to perform an HRA-type of analysis for the conditions and the situation we found ourselves in

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based upon the stator drop.

We were in a shutdown condition, the fuel transfer canal was flooded up. So what we did is we took -- we felt like it was imperative upon ANO to develop a methodology that could be used by the NRC going forward.

We reviewed the standards that were available in the industry and could not identify a definitive standard that could be used for this type of analysis. But, again, our ultimate goal is to get a best estimate factor to be used and acknowledging that it's not 1.0.

So what we did is we determined a -- we assembled an expert team and we considered the different methods that were available. At the end of day the following methods that we ultimately selected were the HRA calculator and we also used EPRI's SHARP 1, Systematic Human Action Reliability Procedure.

The elements that we considered when we went through this development and this methodology was we looked at cognitive and decision making portion of the HEP or the human error probability calculation. We also looked at the design development. And I want to spend a little bit of time on the design development just based on some discussions we had earlier during

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Gary and David's presentation. And also the execution.

So the first thing we want to talk about is the cognitive decision making.

Much like the operator in the control room, when he gets a cue, the cues were self-evident post stator drop. We knew that we had lost our connectivity to offsite power. The engineering starr and the TSC in the plant recognized that we had to protect ourselves against -- protect the safety functions of plant. And we also recognized that we had resources available, and we had to look the modifications that were also available.

Given these conditions, we reviewed the HRA calculator for it applicability. And when we looked at the cognitive portion of the HRA calculator, we deemed that that portion of the HRA calculator for this particular element of the human error probability.

MR. MITMAN: Before you move on, Jeff Mitman here, the HRA calculator has several methods imbedded in it to do cognitive analysis. Which of the embedded methods did you use for this?

MR. HARRIS: Jason, I'll let you speak to that.

MR. HALL: We used the cause-based decision.

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MR. MITMAN: Could I get a copy of the analysis, please?
MR. HALL: Yeah.
MR. HARRIS: Moving on to the next element that we had to consider was the design development. As was discussed during Gary and David's presentation, you know, there weren't any procedures in place. There wasn't any guidance in place post stator drop. It was up to the engineering team to develop these design factors or do the design development going forward.
So, looking at the resource limitations, the effect on effect on existing systems, the operating crew and the staff interaction, taking credit for the fact that we've done this before, the type of modifications we're talking about here were not unique to ANO and they've been performed many times during outages, we did conclude -- and looking at this particular portion of the HEP that the HRA calculator really didn't do a good job of adequately addressing this issue.
So alternate approaches were considered. And at the end of day we decided -- we determined that the SHARP event tree, recovery event tree approach would be an adequate approach to assess this different element

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in the HRA analysis.
MR. KOWALESKI: Just want to make sure of a clarification on a point. We didn't have one individual do this risk assessment in the HRA calculator. We had a team of experts, we contracted experts in to assist us with this. So we had considerable resources applied to this. Just wanted make sure that was clear.
MR. LOVELESS: This is David Loveless. Can you spend a moment explaining the demarcation between where you said the cognitive portion of the action was done versus this, I'm assuming it's part of the action of the design development?
MR. HARRIS: Certainly. In the cognitive portion, you would have to consider the cues that were available to the team as they determine what the status of plan is. They would also have to look at -- compare that cue against the safety's functions because, ultimately, that's what we want to protect.
The team would then go in and look at those safety functions to prioritize. They would look at the resources available. They would look at the temporary modifications that needed to be developed to protect that safety function. And they would make a decision as -- the decision-making point of that would

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be to determine which access to go after first, and which modifications that needed to be planned and developed first.
MR. LOVELESS: And all of that, that you just described, was done with cause-based HRA calculator.
MR. HARRIS: The portion of the HRA calculator that would apply to that, we did.
So moving on to the -- looking at the recover event tree, what we used was, and we've talked about, I think, most of these in Gary and David's presentation, so I won't spend all our time -- we spent a lot of time earlier talking about simple versus complex. From an engineering perspective, this was a very simple modification, and that's why we chose the simple branch on this particular event tree. Again, because we've done it so many times in the past, the engineering team, as David mentioned, he's got a lot of years of experience and done this with many outages, the practice and the ability to do this, the training was there.
We did consider that the nature of the work environment was poor based on stress and safety factors associated with the issue that the team may have been under at the time.

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And that would have led us to a qualitative probability failure to moderate flow and then using screening values as defined by SHARP, we determined that that value would be.03 for this particular aspect of the HRA.
MR. MITMAN: I'm going to have a couple questions on this slide. I was able to get a hold of a copy of SHARP 1 and take a quick look at it last night. I found in there the event tree, the decision tree that you're looking at here, and I understand where you got the questions from and the splits on that.
Could you talk a little bit about the values that put in there that describe short, intermediate, and long, and how you came up with less than one hour, one to four hours, and greater than 4 hours?
MR. HARRIS: The long leg associated with this particular branch is the fact that we had 4.8 days.
MR. MITMAN: Yes, but, again, it was only a quick review of SHARP 1, but I didn't see SHARP 1 defining long as greater than 4 hours, and so I assume that that was a decision that your expert team made as they evaluated that.
Is that a fair assumption?
MR. HARRIS: I understand your question.

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You're saying, where did that 4 hours come from?
MR. MITMAN: Correct.
MR. HARRIS: It came from our HRA anal -- the fleet, southern fleet have an HRA analysis, and the guiding principles within the HRA analysis are defined based on 4 hours. So that's typically what we use for a typical HRA analysis would be a 4-hour timeframe.
Obviously, in this case, the 4 hours didn't apply, and so -- and we probably should have taken it off of this presentation because it does add a little confusion, but the fact that we had 4.8 days did provide us that we had time available for the action.
MR. DAPAS: I guess the question I have is does this human action reliability procedure which I guess is the SHARP 1, does it provide any guidance there regarding the timeframe that you're talking about, long or medium or short differentiation?
MR. MITMAN: Based on -- I haven't thoroughly read SHARP 1 yet to know, and so I turn it over to Entergy and say, does SHARP 1 tell you how to define short, intermediate, and long?
MR. HARRIS: I'd have to go back and look and see if there's any specific guides there.
MR. MITMAN: Next question is, you're using this as an --

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MR. KOWALESKI: That was an output of the expert team, so what we need to do is provide that for you.
MR. DAPAS: Yeah, I think it would be of value for -- I'll ask the risk analysts here on this side of the table, but I think it would be of value for us to understand where you relied on, if you will, the expert judgment of the team you assembled versus applying the guidance that exists and the standards that you were using --
MR. HARRIS: Certainly.
MR. DAPAS: -- HRA calculator or the SHARP procedure.
MR. HARRIS: Certainly. I think that would be -- we can certainly do that.
MR. DAPAS: And of course, associated with that is the basis for the judgment of the exercise and why you considered that reasonable.
MR. HARRIS: Okay.
MR. MITMAN: And looking at SHARP in the column that's labeled qualitative probability of failure, if I remember, that comes right out of SHARP. The low through high-end state qualitative values. In the far right column you associated some quantitative values. Did that come directly out of SHARP or did that

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come out of your expert judgment?
MR. HARRIS: If you look in SHARP, it will define an upper bound of 0.1 and lower bound of 0.01 and then it also specifies that for those that -- a range between low and high, that the range be distributed evenly. So it's somewhat subjective as to what goes where, but there is a little bit of guidance to chart as to how to assign these values.
And our fleet guidance, the Entergy fleet guidance, we've used, we've done that. So this information that you see here, these numbers came right out of our guidance, our internal fleet procedures.
MR. MITMAN: I'd like to see -- could I get a copy of that guidance, please, and could I get a copy of the entire analysis on, you know, how you set the tree up and how you made the decisions on the branch points?
MR. HARRIS: Okay.
MR. MITMAN: And the last question about this is, you've characterized it as a decision tree for evaluating the engineering judgment. But isn't it a little bit more than that? It's the engineering judgment and the actual construction work that went into building the connection between offsite and onsite power?

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MR. HARRIS: No, this is just dealing with the design development where we looked at, you know, what the engineers had to do to put a process in place and develop the guidance, the written instructions, to provide to the craft in the field to perform that execution -- that activity.
MR. MITMAN: So you're going to talk shortly about the evaluation of the execution?
MR. HARRIS: That's right. So the next element we would talk about is the execution factor. And what we looked at here was the execution steps that were developed for successful implementation. Again, what Jason did in his analysis, was he took the, actually, work order instructions that were developed and he used those in the context.
We did determ -- the team -- say -- I'll clarify that. The team determined that the HRA calculator could be used for this application because if you think in terms of the HRA calculator and how it's structured, it's structured to be used via procedures for execution. By the time we get to this portion of the recovery, the team in the field will have constructions available to them that were developed by the engineering team.
And so using the temp mod process the

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written instructions were developed. We used those written instructions as part of this analysis and deemed that the HRA calculator could indeed be used.

So now that we've gone through these various elements and we've determined which tools could be applied, what we did was we actually did the quantification. And I'm just going jump right along, move right along and we'll look at the fault tree that we used to quantify this particular recovery.

What you'll see on the left side of the screen or on your hard copies in front of you is actually the recovery associated with the Startup 1 recovery. The branch -- the event that you're looking at here at the bottom actually is the numeric value quantification results from the HRA calculator for this particular element.

On the right side of the branch here you'll see the recovery efforts associated with the 2A9 and also the condensate pump feeder breaker. And you'll note than that they are anded as two independent recovery efforts, but there is a dependency here associated with the alternate AC 2A9 recovery and the condensate pump recovery.

Also you'll note at the top of the tree, the development of -- the design development factor.

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This is the factor that came out of the SHARP 1 methodology. So what we've done is we've used this fault three tree to capture the portion of the analysis we could perform in the HRA calculator and the portion of the analysis that we could -- would pull from the SHARP methodology, the event tree.

And using this quantification or this fault tree, we did calculate a recovery factor associated with 4160-volt. And you note that rather than put the recovery factor for the design development down in the tree, as -- for each one of these elements we pulled it to the top which provides a little bit of an overestimation of risk associated with that particular parameter.

MR. MITMAN: Jeff Mitman. Before you leave that, the far left solution is the actual solution that you implement, correct?

MR. HARRIS: No, this is actually the success, this is actually one of the success paths that we presented to you.

Now, given the way that we quantify this value, it wouldn't change very much if we were to assess it based on what we actually did.

MR. KOWALESKI: But, to be clear, the actually installed power recovery is not included in the

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model.

MR. HARRIS: So, using this fault tree --

MR. LOVELESS: Can we go back for a moment? This is David Loveless. I guess I'm trying to understand exactly what you're modeling here in the two recoveries under an or gate -- those are recoveries 2 and 3 that have some combination, so there's really a 50/50 chance that you take on each one of those, right? I'm not sure the quantification is right putting those both under an or gate.

MR. HARRIS: And I'll have to look at that in a little bit more detail, David, you may be right. But I will point to the fact that this risk here is going to dominate these results.

MR. MCKENNEY: In actuality -- this is David McKenney -- we would have pursued that particular path and you could use it either place, so it wasn't -- in the development and the design section you could have just moved the termination point from one place to another.

MR. HARRIS: So it would have been a true or.

MR. MCKENNEY: If we had a problem with one of the two breakers, we could have moved to the other breaker with sufficient time.

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MR. MITMAN: But the way you've got it modeled, if one fails then the whole train, then the whole -- then the or gate fails?

MR. HARRIS: Right.

MR. LOVELESS: The other question I have is that, I guess, are these numbers your cognitive and your execution --

MR. HARRIS: Yes they are.

MR. LOVELESS: -- values?

MR. HARRIS: Yes they are. We didn't break them down in -- used HRA calculators using those two elements to come up with a value that we used in this fault tree.

MR. LOVELESS: And when send those to us, we'd like to actually have the calculator files so we can pull it up in calculator and look at your selections on your usages.

MR. HARRIS: Sure. Okay. So as we quantify the fault tree, our resulting point estimate is 3.1E-2 for this particular recovery pattern.

MR. LOVELESS: Before we leave this, one more thing that I struggle with as I'm looking at this and I struggle with it every time we're looking at a complex event occurs and you have multiple pathways.

You're modeling pathways that you've

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determined at this point would be success paths. But at the time of an event, it just happens, you're not sure what the conditions are, there are going to be failure paths, and those paths are going to be split fractions with these, so they're going to pull off resources, they're going to pull off decisions and you may make the decision to go down a failure path, and that's not modeled in here.

MR. HARRIS: Well, HRA we don't model failures of commission.

MR. LOVELESS: We don't typically try to model recovery after a dropped stator.

MR. HARRIS: The questions you're asking are very good questions, and I was thinking earlier when you guys were quizzing Dave and Gary, the questions you asked us are questions any good PRA or risk analyst would ask. And so, when I came on board to participate we asked those same questions.

And I asked these guys, you know, did you really do this? And if you did, how did you come to this conclusion? And if you came to this conclusion, how did you develop these success paths and how far did you take it? And I walked away from that conversation with these gentleman convinced that those guys had done the right thing and developed the right tools and the

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right models and the right strategies to develop this particular recovery action.

MR. LOVELESS: And I understand that. I understand that you took a look at one item and said they did the right thing here, but we're talking about failure probabilities in each of those in the one in a hundred range. So this happens a hundred times and you're going to have different groups of people in your TSC, different response teams, how many times do you have to get that group together before they come up with a failure path that goes the other direction?

MR. KOWALESKI: The whole premise, because it's an event that occurred and setting the event frequency to one, is that this event occurred. And so it occurred during this outage. And that's in essence what's bothering you. And I think if you look at the timelines, there is substantial margin in time to account for a lot of these deviations from normal practice.

And typically the timelines for an online model your talking about are a couple hours to taking action, minutes to taking action. And we're talking days to taking action. And so, we could have given these installations -- design an installation in time, could have gone down the path, failed option one, gone

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to option two, failed it and gone to option four sequentially.

If we'd have done that, we'd have pursued parallel paths, but given a different set of circumstances, would the design evaluations come up a little differently? Yes. But what we are looking at the circumstances that occurred, which is the whole basis for setting the event frequency at one in the first place.

MR. LOVELESS: Well, we set the event frequency to one and then we have, what we'll call failure memory model where everything beyond that can fail in different ways at whatever their nominal value is. Unfortunately we don't have data to show what's the nominal value of your TSC failing to come up with these ideas. That's the struggle in using these.

You're modeling the three that you thought of on that day, and I'm not -- they're probably the best thing for your plant, you know your plant better than I do, I'm not challenging that at all. We're simply looking at the frequency and probability of failing under those types of conditions.

MR. DAPAS: You had a comment.

MCCANN: Thank you. John McCann, Entergy. We clearly acknowledge that this is, to some

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degree, new ground, right? I mean, we're at a place where, I think we would all agree, probability of failure of any of these success paths is not a hundred percent. But then what is it?

I think this approach that we've come up with is clearly going to be subject to some tweaking, to some rethinking. But what we're trying to get across here is this is a logical way to approach it that is kind of consistent with the way we normally do probabilistic risk assessment. I'm sure we will have more than ample opportunity, hopefully, to discuss it further, but, you know, for now, that's what we're trying to get across.

MR. DAPAS: I'd offer, John, from looking at your slides and listening to your discussion, you indicated you're looking for the realistic estimate of risk here and you feel that the probability for failure to restore offsite power was something less than one.

Now how do you best determine what that probability is, and then, you know, what influence does that have when you apply that to your event tree. And so, I heard there's no definitive standard for calculating the recovery actions you were using.

The methodologies and guidance that is available in trying to determine how best to provide

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that realistic estimate of the risk. I'll offer the questions you are hearing here is in a vein seeking to understand how you apply those and may have some different views on how best to apply those, but the objective, clearly, of this conference is to understand how you applied those and how you arrived at your results.

And I'll offer, should we arrive at a different conclusion, we are subject to the same rigorous evaluation or review of how we got there and we have to clearly justify our conclusions and what methodology's we used and do that.

MR. SULLINS: I hope it will help, I was a member of the team from the operations' perspective and I would look at final result and is say, is that reasonable, also look at the activity involved and what are the fatal errors that one could make. And the key thing is you don't cause damage through your recovery activities, and there are very few of those type errors to make, given that we would apply electrical testing standards, measuring and checking that there's integrity before you put power on a circuit.

And given the time, it's in the modeled, but when I looked at are those numbers reasonable, I'm recognizing that if there's a logic error when they were

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correcting the -- or adjusting the logic in the circ water pump breaker, there's ample time to adjust for that and achieve success. So that was the sanity check applied from an operations perspective.

MR. HARRIS: And the main thing we want you to get out of this is to understand what we did. And you asked some good questions and you've asked for some documentation that we owe you. So we can sit down, you know, outside of this purview and go through the analysis and we'll be available to answer any of these questions as well.

So, in the alternate evaluation, really what we're doing here is we're just trying to take some different approaches, much like Gary said, that it makes sense to him that what we were doing was reasonable and the results we were getting were reasonable. So we took just a couple of different approaches to say does the numbers that we're getting make sense in relation to a different look.

Here we looked -- we just used a simple statistical method, and using a normal distribution, mean time to repair, assuming 60 hours, which is the long leg for the Startup 1 recovery effort, and a standard deviation of 20 hours, gives you a probability of failure of 2.6E-3. Just a simple look.

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MR. LOVELESS: We read this slide earlier and weren't completely sure what you were saying. You started with -- well, maybe I'm wrong. Why don't you start with how you applied that.

MR. HARRIS: We didn't apply this, first off. We did not apply this. All we're doing here is we've already established what we feel like is the best estimate, and using the method that we discussed a few minutes ago.

MR. DAPAS: 3.1E-2.

MR. HARRIS: That's correct.

MR. KOWALESKI: So this is just if you look at it a different way is it even close.

MR. LOVELESS: I understand, but we're not clear on how you looked at it.

MR. HARRIS: So, we simply took a macro that was set up to do, using normal distribution, calculate a probability of success, probability of failure. We went into that, again, looking at the mean time to repair, which, again, we assume to be 60 hours. 20 hours we assume for the standard deviation, and then we calculated, basically it's a plug and chug within this particular application, put in those values, see what you get out for success.

MR. LOVELESS: So the distribution was a

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time distribution and you just randomly sampled the across it and said the tail is --

MR. HARRIS: That's right. It's a very simple analysis.

MR. MITMAN: So the 2.63 is the mean failure probability out of that analysis?

MR. HARRIS: That's correct. Jeff clarified that in his slide.

MR. MITMAN: The 2.6E-3 is the mean failure probability out of that analysis.

MR. HARRIS: That's right.

(Many speakers on top of one another)

But it's all driven based on the assumption that 60 hours and a 20-hour standard deviation are correct.

-- that is correct --

-- we have a high degree of confidence --

-- if you could change those --

-- based on the discussions --

-- the 20 hours, we could debate that all day, but I don't think that would serve our mutual purpose.

MR. DAPAS: I think we're making progress in terms of it being all day here.

MR. HARRIS: I'll try to help us along.

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So alternate two, in this case all we did was we assumed the fact that we did have off offsite power restored in 4.4 days, we knew that we had an available time of 4.8 days. We look at the fact that night orders were in place, operator actions to close the breakers and energize the buses were not complicated, and we simply did an HRA -- used the HRA calculator in this particular application to find out what the value would be for failure probability, and we came up with 2.0E-3.

Again, this assumes actual condition. We were, we actually had power, how long would it take us to get that power in place should we need it.

MR. LOVELESS: Rather than assume for you, once you -- the conditions you were at, my understanding, you had to make a decision that you were in an emergency, you met your emergency standards. Some amount of time, I'm assuming not a lot, at that point you had to go out and close the breaker, what's the next operator actions at that point? You've been boiling in there for a long time, you're way down, I'm going to guess probably whatever the next operator actions, the timing, just getting power to the bus is not successful by itself.

MR. HARRIS: That's a very good point. All this looks at is restoring power to that bus. There

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would be additional operator actions that are needed. We didn't look at those. And those would increase this value as well.

But again, looking just looking at this perspective, we felt like we've got at least an insight that we didn't have before. And were we to include the things you're talking about, this number would go up. How much would it go up? My guess, it would probably double or triple. So it really wouldn't invalidate what we had done before. Good question.

So the final thing we're going to talk about is the inventory recovery in relation to the NRC. We looked at the event tree here and concluded there was no real credit given for this particular recovery action here and David spent a lot of time looking at it. One of the things we looked at in relation to the 4160-volt and the inventory recoveries was, is there any dependencies?

And the conclusion, ultimately, is, as was discussed earlier, there were no dependencies between 4160-volt recovery and the inventory control. We had sufficient resources on site to pursue those paths.

MR. MITMAN: Before you leave that -- Jeff Mitman -- the three other contingencies that you

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developed to supply power to the 4160 buses. Those were to some degree scoped out during the event, okay you had those conceptually in your mind, you started to think about them and what resources you would need and what analysis you would have to do and maybe even start thinking about writing work orders.

But this other contingency to supply 480-volt power to the borated water transfer pump, you didn't think of that during the process, during the event. That was something that was developed after the event was over, you restored power, and now you were thinking about risk.

Do I understand that correctly?

MR. HARRIS: That is correct. But as David and Gary talked about earlier, our processes would have driven this.

MR. MITMAN: Personally, I think that this is a success path with -- it's a very valuable success path. Have you incorporated it into your procedures as of this point more than it was previously incorporated into your procedures.

MR. HARRIS: I'll let Gary or David respond to that.

MR. SULLINS: Not yet, but we've had active discussions regarding that. It highlighted the

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value of this pump and this strategy.

MR. MITMAN: I think your point here is a very vital one, and that is that it's a method that's completely independent of your failure. And so you don't have to worry about, well, if it happened a little bit differently, you know, the damage would have been somewhat different. It doesn't matter. You can simply run something into the plant, know it's coming from a good source, know it's going to an MCC that can be thoroughly isolated from whatever the fault is.

MR. HARRIS: Let's go ahead and move on and we'll look at how we modeled this in the fault tree. On the right side of the fault tree, what you'll see is the alternate source of water, the BWST, and that was a question, I think, Jeff had asked earlier today in the discussion was what about the BWST. What we've done is we've modeled restoration of water to the BWST in order to account for this particular recovery.

We've also thrown in the failure, mechanical failures for the necessary pumps and then over on the left here, you'll see the development of recovery, the same thing we used from the SHARP 1 event tree model, and the HRA calculations assuming the cognitive execution steps.

MR. LOVELESS: This is David Loveless.

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The whole right side of this looks like it's fire water.
MR. HARRIS: We have the B5B pump. We assumed credit for a fire truck that was on site at the time. And then we had also a decent fire water pump.
MR. LOVELESS: Well, during the event we had broken headers and that affected mostly how do we -- how would that have come into play?
MR. SULLINS: We have three portable pumps. And this would have been given priority for at least one. We called the local fire department, the London Fire Department was on station standby as a contingency for fire water. We did isolate the fire main, the ruptured section, within a couple hours so the fire water pumps were available to restore pressure to the header in short order. So I don't see that as a competing factor.
MR. LOVELESS: The portions that were damaged were not used in your fire water makeup procedures?
MR. SULLINS: No, it's independent.
MR. BROWNING: It's completely on the other side.
MR. MITMAN: The fault tree that you've set up here and we've been talking about this fire protection component of it. That's an or gate up there.

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Didn't you intend that to be an and gate that not one of, you know, the way it's currently written, any one of these five things fail and the whole scenario fails.
MR. HARRIS: That's right.
MR. MITMAN: And so it should been an and gate and not an or gate.
MR. HARRIS: Well, when you look at the failures, though, we've got a common cause failure of all the pumps -- you've got a common cause failure -- you also have a hydrant -- we have a valve closure here. So these failures -- and then the operator action to align off that water source -- the recovery action to actually take those steps -- so any of one of those failures would have caused failures to the --
MR. CIRCLE: They need to isolate the hydrant from everything else.
MR. DAPAS: The answer here is you feel an or gate is appropriate. We were questioning why it shouldn't be an and gate.
MR. HARRIS: We believe it would be nonconservative to apply an and gate there. Something we would definitely go back -- we'll go back and revisit that. But we believe that to be the case.
MR. DAPAS: I think our role here is to see if we can understand why you decided to use an or

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gate.
MR. HARRIS: And just to go to the top again, you know, the operator action. If the operator fails to perform this action, this top gate fails, regardless of anything else. That's the biggest argument for the or gate.
If you quantify this model, or this fault tree, we get a value of 4.0E-2. So, given the recovery factor we've talked about the results, when we apply these to the NRC's event tree model, and again, we don't have the entire model, but given what we do have, we feel like the -- well, from the results that we've determined would be around 5.5E-06 conditional core damage probability.
MR. KOWALESKI: I do believe when you look at two of the inputs on the ultimate source of water, I believe one of them should be an and gate here. I think they're all or, but I think we did have an and.
MR. HARRIS: We can certainly go back and revisit that. It really won't affect the overall results. The numbers down there are not going to be significantly -- was there another question?
MR. BROWNING: This is Jeremy. I was going to make a comment about the concept around what we were doing. If I could bring you back to the

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discussion. An element of this is something that we would have done during every other refueling outage, so the concept to put it in place, given the question, you said, you'd have had to thought all this up because you didn't have it.
The concept would have already been there because we're jumpering between two buses that we would typically do. That other leg that would come off from this connection, we have used that, not in this specific application, but in a similar application. So that's why, from my perspective, the basis for why this would be credible is the concepts were pretty much already on the table. Although we didn't ask the question during the event because the need never arose.
MR. HARRIS: What you're looking at here in relation to -- we performed a sensitivity analysis on the results. Basically, using a factor of about 10 low and a bounding upper value estimate of 0.1 for the 4160-volt recovery and the inventory control, Jason performed this analysis. And basically, we got a range of values in E-06. You'll notice the gray blocks in the middle is approximately what we got for the point estimate.
MR. LOVELESS: Can you explain this to us a little bit better? What it is your --

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MR. HARRIS: If you'll look in this column here on the left you'll see 4kV recovery. The mean value, the point estimate value that we used in the analysis is here. Simply went, approximately, in order of magnitude low and then a bounding value of 0.1 to the high end.

Same thing here for inventory control. The mean value is here with a lower value of about, approximately, 10 and up or down 0.1. So if you go to either one of those boxes here, you can cross reference and determine what the value you would get if you assume 0.1 and 0.1.

MR. CIRCLE: So all the 4kV recoveries are all the success paths? Combinations of success paths?

MR. HARRIS: The 4kV would be the fault tree.

MR. SULLINS: It was dominated by the design development factor which was applied at common point.

MR. CIRCLE: Right, thanks.

MR. HARRIS: Now, real quickly I would like just to present, you know, we looked at -- Jason developed an event tree model and quantified the ANO model using the same results that we've talked about in

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this discussion today for recovery factors.

Modifying that model, we calculated the value of 4.8E-06, which is relatively close to the value that we projected that the NRC model would provide. So in conclusion, I think we can all agree that overwhelming evidence that the fault of the failure for 4160-volt KV is not 1.0. And ANO has researched and instituted what we believe to be a reasonable method for assessing risk of recovery factors.

And the bottom is just simply restating what I stated a few minutes ago, that we believe the value to be in the E-6 range associated with risk for the stator drop event in Unit 1.

MR. DAPAS: You came up with 4.8E-06 as the overall CDF, right?

MR. HARRIS: Not CDF, CCDP. That is correct.

And that concludes our presentation.

MR. KENNEDY: I know we asked a lot of questions about the SHARP 1 methodology and your evaluation and the process, but I want to hear from both sides. Is the use of that a revolutionary method in our opinion or we just don't know enough about it?

MR. LOVELESS: I think SHARP is kind of somewhat outdated method. It wasn't put into the HRA

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calculator, which has a large number of methods in it. I don't think we have enough information right now to put our hands around it and say that we agree with their decision that it was the best tool. I think we do agree that there isn't a definitive method for doing this kind of work.

MR. MITMAN: And if I can add to that. This is Jeff Mitman. It does add some insights in that it's only method that I've ever seen that talks about non-proceduralized actions and untrained actions and speaks directly to equipment -- trying to calculate equipment recovery probabilities using a human reliability method.

So it adds some insights that we didn't have otherwise. But it's not a widely used, widely adapted, widely geared to methodology. But there's a lot of interesting insights from it.

MR. KENNEDY: Then just another follow-up. Making an assumption about what our HRA calculator limitations are, but just to confirm, I assume our limitations are associated with what you just described, Jeff, lack of procedures, lack of training, et cetera or --

MR. MITMAN: It goes a little bit beyond that. The guidance that we have on how to deal with

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this is expressly laid out in RIS 2008-15, which is specifically written to how to credit in pure A for SDP and applications. What we call B5B measures, which is what we're discussing here. It's un-proceduralized use of non-permanently installed equipment.

And the guidance in there says that if you don't train and you don't have procedures and you don't have the methodology in the base model, you get no credit. All right? That's what the risk says, and that's what collectively the circ panel had to contend with during our evaluation process. And that's what we'll have to contend with as we go back to make a decision.

MR. DAPAS: I just want to comment. I was going to make reference to this in my closing, but I think it's appropriate to comment now. We have guidance. We need to look at that and, you know, your overarching point here is that the recovery probability here is not failure to recover, is not 1.0. You provided your view on what is the best estimate to use for that.

I think we need to look at that in the context of what existing guidance we have here and determine does your approach seem reasonable here. I understand where you used SHARP. I understand where

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you've used the HRA calculator. We need to look at that and determine independently here, do we feel that you applied that appropriately and are your conclusions reasonable here.

Probably -- a reason why our guidance says, you know, you should use X, Y, and Z here, right, because it's probably a function of our experience over time and the challenges you face in trying to come up with reasonable risk estimates. So, I think you've done a very good job in my view of explaining how you applied the methodology, how you arrived at the risk numbers that is you did.

I's offer, unless we have any other questions about how they applied it, I actually see we have "break" on the slide here, which leads me to the next point here. Do you want to take about a 10-minute break? How would you like to proceed here? We've been at it for awhile.

MR. KOWALESKI: Before we go there, I would like to add one more point of view to whether a order of magnitude risk from normal risk is reasonable for the post-event conditions that existed. And that point of view would be to go look at what's the required power supplies, given a normal outage.

So in a normal outage with reactor vessel

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head off and 23 feet of water above the vessel. The shutdown outage protection plan would require one offsite power supply and two other power supplies or two emergency diesel generators, three power supplies.

It would require only one decay heat train and that's because that large inventory of water is essentially credited because if you have a decay heat train fail, there's substantial time to recovery that opposite decay train service. So that the difference between the equipment available after this event in a normal shutdown outage protection plan is the one offsite power supply.

If you look at tech spec requirements for reactor vessel head off, it's flooded up, 23 feet above the fuel, the requirements are two power supplies. It requires on offsite and one generator. It requires only one decay heat train.

So the difference between what we had and what's required by tech specs for that plant condition, flooded up with the vessel head off, is that one of our power supplies was a diesel generator instead of an offsite power supply. That's the only difference.

And when you look at the reliability of a diesel versus the reliability of the offsite power, or the frequency of the loss of offsite power, they are not

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substantially different. So when you do kind of a comparative to the plant condition after the event to normal outage required conditions, and tech spec required conditions, it seems very reasonable that a one order magnitude of risk is represented. Because all you've done that's different from tech spec requirements is replace an offsite power supply with an emergency one.

Just an alternative way of looking at it in terms of is this realistic, believable, reasonable that this would be the outcome of a significant success.

Do we need a break?

MR. BROWNING: Mr. Dapas, it's up to you. If you would like a break we can take a break. When you come back we will look into the Unit 2 risk assessment and insights and additional information we would like to provide. And conclude with our corrective actions around the event.

MR. DAPAS: All right. Let's take a five-minute break here. And I will try to set the example by being disciplined in that regard. If we could come back in five minutes that would be great.

(Break taken from 4:44 p m. to 4:52 p m.)

MR. BROWNING: Okay. This is Jeremy Browning again. Just kind of refocus us a little bit.

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We're switching units. We're going to start talking about Unit 2. Unit 2 is a quite a bit different in that what we're going to be talking about from success paths, we're not talking about design development-type things. Everything that we're going to talk about asking for or pursuing credit is already modeled in our PRA. There's no difference on Unit 2 than Unit 1, the operators did respond in an appropriate manner and all our safety-related equipment in actuality did perform it's intended function.

Some of our priorities, what we decided to do and what we decided to pursue on Unit 2 is based on actual plant configuration and not the postulated. If I could I'd introduce John Hathcoat, he is our shift AOM, and he was in the control room the day of the event.

MR. HATHCOAT: Thanks. I want to try to move things along, so if I move too fast, please stop me. We'll go back and I'll answer questions. The objectives I want to talk are procedurally directed electrical power recovery strategies. Specifically three different options we had: Offsite power coming in, and I want to use in diagram quite a bit, offsite power coming in from Startup 2 to our 2A2, which is our non-vital 4160-volt switchgear, talk about that

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availability path. Alternate AC diesel generator to 4160-volt 2A9 bus, which we already talked quite a bit about that, that availability path. And also the ability to cross tie between red train vital 2A3 bus, 4160-volt bus, and green train 2A4 4160-volt bus. The ability to cross tie those.

So those are the three main recovery strategies I want to talk about. And the availability of each one of those independently reduces the overall risk profile for Unit 2. And then talk a little bit about the differences between the NRC model and the ANO model and how there's no credit provided with the NRC model.

Just a quick overview. Unit 2 was a hundred percent power when the event occurred. We had a reactor trip, as you guys have alluded to, uncomplicated post-trip response. The staff did a good job stabilizing everything, going through diagnosing reactor trip recovery.

We had normal fast transfer from our unit aux transformer over to our Startup 3 transformer that powered our red side and our green side. And there was no issues with the plant. Everything was stable at that point. And we were supporting Unit 1 at that time.

About 90 minutes later, we had a Startup

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3 lockout. And that was a result, the water migration into the 2A1 bus from our Startup 3 to 2A113. That created a Startup 3 lockout, at that point we fast transferred power over to Startup 2. Startup 2 automatically tied onto our red side, 2A1 bus to our 2A3 vital bus, stable.

I did want to point out it did not fast transfer over to the 2A2 non-vital side because of the configuration of our hand switch. We hadn't pull-to-lock, which basically is a configuration that will not allow the breaker to automatically close.

I do want to point out it was available the whole time if we needed it. I'll talk a little bit about that. We had a hundred voltage condition on the green side 2A4 bus, the No. 2 emergency diesel generator automatically started as designed, tied on, we had a stable condition. We had power on the green side, a vital from our diesel, red side from offsite, everything was stable, we were focusing on Unit 1 at that point.

MR. MCKENNEY: John, just a couple clarifying. This is David McKenney. The fault actually happened between the transformer and the breaker. So it did not happen in the breaker, it was in the bus work between those two.

MR. HATHCOAT: Thank you, David.

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MR. MCKENNEY: And then the reason the diesel generator started on the green side was because of the Startup 2 breaker being in (gets too quiet to hear).

MR. KOWALESKI: There's a particular vulnerability for how that bus comes through the floor. It's different than a breaker. So a small amount of water on the floor doesn't cause an issue with the breakers like it does with that bus coming through.

MR. WILLOUGHBY: This is Leonard Willoughby. I have one question. It was on slide 75. You said you had an uncomplicated post-trip response. Can you please define uncomplicated?

MR. HATHCOAT: Yes, sir. At that point uncomplicated means that there was no adverse conditions that we had to additionally address as far as, like, feed water control, or steam bypass control system; any other additional complications that would create a diagnosis other than reactor trip recovery. So the control room stamped diagnosis reactor trip recovery and stabilized the plant at that point.

MR. WILLOUGHBY: My understanding is that you had a problem with the feed reg valve, you had a mismatch indication, wouldn't that complicate the trip response? Because you had to send operators out.

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MR. HATHCOAT: We did, we actually actuated emergency feed water during the trip, but the alpha main feed reg valve failure did not constitute a complication. That question's come up and we've addressed it.

MR. BROWNING: I guess by definition, we call an uncomplicated reactor (unintelligible) if we go into reactor trip recovery. If we diagnose an off normal procedure that would require us to go to an emergency operating procedure or an abnormal operating procedure, we consider it somewhat complicated. But because the operators reactor trip recovery, there were no significant challenges, although there was a problem with the P reg valve that did not constitute, for example, a loss of heat or challenge the operator's recovery.

MR. MITMAN: Jeff Mitman. Just so I'm clear. It's my understanding that Unit 2 being a CE plant, post trip the normal feed water supply to the steam generator to this main feed water.

MR. HATHCOAT: It is normal.

MR. MITMAN: But because of an indication problem with a feed reg valve, the operators shut down normal feed water, main feed water and went to -- I don't know whether you call it emergency feed water or

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aux feed water?
MR. HATHCOAT: That's right. Emergency feed water. We have a condition called reactor trip override, and that main feed water control system goes into, and if it did not go into reactor trip override, which the indication was it didn't, we trip our feed pump and make sure emergency feed water is actuated. That did occur.
MR. MITMAN: And just so everybody understands, the analysis that we did, we didn't do a normal transient analysis, we did loss of feed water analysis. We used the loss of feed water train event tree rather than a transient event tree. Giving credit for emergency feed water.
MR. HATHCOAT: Leonard, did we answer your question, sir?
MR. WILLOUGHBY: Uh-huh.
MR. HATHCOAT: So talk a little bit about our Startup 2 design and why we were in a (pull-to-lock?) configuration to 2A2. Basically, Startup 2 is capable of supplying both units as we talked about. We have procedures that limit the number of the buses that can be automatically transferred to 2A2, but as I mentioned, the configuration we were in, we could have came out of the pull lock condition and it would automatically tie

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on the 2A2 if needed. And it's capable of manually loading 2A2 from our Startup to our transformer.
So we had Startup 2 transformer available for green train. We had procedural guidance to manually energize 2A2 if we needed it, but we were in a stable condition at the time with red power being supplied from off site and our green vital switchgear being powered from our No. 2 diesel.
So we were in a stable condition, and we did later transfer power to 2A2 from Startup 2 successfully with no issues.
So Unit 2 was in a stable condition with power to all our safety equipment. Redundant systems were available for decay heat removal, and the alternate AC diesel generator was not damaged from the Unit 2 side as we talked about earlier, and it was available.
And we initially declared the alternate AC diesel generator in 2A9 unavailable, and that was based on the function of 2A9 and alternate AC diesel generator having to supply Unit 1 and Unit 2, both. So we did not fully assess the damage to 2A9. We believe it was just from the feeds going to A1 and A3 on the Unit 1 side. We later confirmed that.
I mean, the big thing is we didn't need it to support Unit 2. We had, as I mentioned, both

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diesels available to us and offsite power. We had at this point, basically four or five power supplies available to us.
MR. LOVELESS: This is David Loveless. I know we talked a little bit about it when we were in -- talking abut Unit 1, but I do believe the AIT interviews indicated that operators in Unit 2 did not believe alternate AC diesel was available to them for some period of time.
MR. HATHCOAT: To answer your question, I've talked to the control room supervisor, the shift technical advisor, the shift manager, and multiple SROs that were there, and I was there that day, too. We didn't really have a good understanding of any damage of 2A9 until that afternoon. So it was, we fully believed it was available to us to that point. Then we got the indication that, hey, there's damage or the cable pull from going to Unit 1 is pulled out.
Now at that point, the question is kind of subjective. It's like, okay, well, do you follow your procedure if you need it in a blackout condition or do you go down and asses it before you actually use it? Half of the SROs I asked would basically say we would follow through. I know it was just the damage to the Unit 1 side, there was no issue with the breakers on

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Unit 2. We would have used it, the shift manager basically indicated that, yeah, I know there's something, I think it's isolated to Unit 1 feeds. I would have relay techs go down there and look in the back just to make sure it is isolated. So there is some subjectivity to that, but every one of the SROs that I talked to believed it was available.
MR. LOVELESS: Do we have capability -- I know that on the bridge the AIT team lead, but I also know he can't ask a question.
SPEAKER FROM PHONE: Actually, David, this is Geoff Miller, I led the augmented inspection team. There was a log entry in the Unit 2 control room logs at 1:30 p m. that indicated that the 2alpha9 bus was degraded and the alternate AC diesel generator was unavailable for either unit.
MR. HATHCOAT: Right.
MR. KENNEDY: I was wondering where they were going because your bullet says initially declared unavailable. So I think that...
MR. HATHCOAT: Yeah, that is not -- that is a poor choice of words right there. Initially it was declared unavailable at 13:30 when we got the feed back from the field at that point.
MR. KENNEDY: But up until that time,

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operators -- that's what we're talking about. Between the time of the event 1300, the question is whether operators thought it was available or unavailable?

SPEAKER FROM PHONE: This is Geoff Miller again. I'd also like to just bring out that in that period of time there also there had been an emergency declaration on Unit 2 and there was a loss of let down, a loss of charging, trip of all reactor coolant pumps, so by this point I wouldn't consider to have been uncomplicated.

MR. HATHCOAT: Well, now that was later. This was the Startup 3 lockout which was 90 minutes later when all those conditions we were dealing with in the control room. The post trip response was uncomplicated. Just to clarify that.

SPEAKER FROM PHONE: That is true, but power for Unit 2 really didn't become an issue until that point.

MR. HATHCOAT: That's right.

MR. DAPAS: I think it's fair to say you had some challenges here in dealing with the event and recovery associated with Unit 2. I understand the post-trip recovery was uncomplicated per your definition of what constitutes complicated versus uncomplicated, but I think the salient point here is, you had some

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challenges here that you had to address subsequent to the initial event here as a result of the impact on the bus work here, right?

MR. HATHCOAT: That's correct. Let's talk a little bit about priorities being dictated by our circumstances. If additional power challenges were to occur after the Startup 3 lockout, we would assess the condition that we had, whether it be a loss of offsite power of Startup 2, transformer were to go away we would have lost both of our diesels and we would have had a station blackout condition, or if we would have had a feed source with our steam driven EFW pump, we would have diagnosed appropriate EOP, and we would have pursued recovery power based on that scenario where we re-diagnosed.

The priority would be feeding from Startup 2 if it would be available. In the loss of all site power condition, obviously wouldn't be, but in this case, if it was available and we lost power to our vital buses, we would pursue bringing power in from Startup 2 is it was available.

We had procedural direction to do that. Operators are trained on it in the simulator and the classroom. And really the only action that we would have to take in the control room would be taking the

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hand switch for 2A211 how to pull a line, it would automatically tie on. So procedural guidance, operators would have that available to them to do that.

The second path in a blackout condition would be the alternate AC diesel generator, and again, we're talking about the availability of it. The fact of the matter is, it's physically available to us. We confirmed that later. The question is, how would the operating crew go about getting to that point to starting it up and loading it. And that's kind of up to debate a little bit right now as to whether we go down and inspect it or we would just execute the procedure as it's written and tie it on.

And then the cross tie capability of 2A3 and 2A4 is another point that we would use, depending on where power was coming in, we had the diesel available on this side, our offsite power available on this side, we could cross tie over and get our electric driven steam pump to our steam generators which is supplied from the red side.

So that gives us that capability. Same thing here, if we had power coming in we could cross tie 2A1 and 2A2 you get [coughing] steam pump, which is non-vital but is fully capable of supplying our steam generator. Do depending on the combination and safety

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function that we needed at the time, we could cross tie our buses.

As I mentioned, the feed from Startup 2, we proceduralized -- I won't talk about that a whole lot more, I think everybody has a picture on it. Certainly available to us. I don't want to say simple action, but it's one hand switch in the control room --

MR. CIRCLE: This is Jeff Circle. Does Startup 2 have enough capacity for both trains?

MR. HATHCOAT: It does. And then the alternate AC diesel generator, you know, the feeds to Unit 2 were unaffected. Visible damage, we talked about being on the Unit 1 side only. It's fully capable of supplying our loads. And this was later confirmed by engineering and electrical maintenance that there was no issue on the Unit 2 feeds from 2A9.

And the big thing I want to point out is 2A9 at this point was not given a high priority because of the stability of the plan on Unit 2. We had offsite power in, we had a diesel that was running, another operable diesel. So our focus, really was on Unit 1 and supporting them at this time.

And I mentioned, emergency, you know, EOP for station blackout condition, we would have used the alternate AC diesel generator to start it and tie it on.

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Just to give everybody perspective, it takes about -- once the time the blackout would occur it takes us about 15 minutes to re-diagnose the blackout and give the direction to the director operator to actually start it and tie it on.

So it's about a 15 minute evolution once we actually have the condition. And that's adequate time available to establish a feed source to our steam generators. And that's considering, you know, we have in this scenario, in a blackout, we have our steam driven EFW pump feeding both steam generators.

A blackout gives it, at six-hour point, due to battery depletion, we actually say, okay, let's go ahead and send a local operator down, take manual control of the 2P7 alpha turbine due to DC control circuitry and the DC valves and then transition over to that.

Before go to that point, 6 hours into the procedure, we would have had adequate time for the control room staff to call relay techs, send them down to 2A9, look in the back of it and say, yep, it is just isolated to Unit 1, and you guys can move forward with tieing it on to one of our safety buses.

That's why I wanted to point that out. Even though there is some question about some SROs would

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move forward with it, some of them would, maybe, suggest going out and getting the relay techs.

MR. CIRCLE: This is Jeff Circle. Are you saying that this -- all these activities could be completed in 15 minutes? Send technicians down?

MR. HATHCOAT: No, sir. I'm saying normal procedural guidances is to diagnose the blackout and then give the direction to tie it on procedurally in the control room.

MR. CIRCLE: Right.

MR. HATHCOAT: But if we'd have had a condition where, say the shift manager -- hey, I want to call relay, send them down there, look in the back of 2A9 and make sure that there's no issue with it, we would have done that in, say, an hour or less.

MR. MCKENNEY: Yeah, I talked to the relay techs and asked them specifically how long would it take in a blackout condition. They said it would take about an hour and about an hour to get it reenergized. To go to Megger the bus to verify that it was not damaged configuration and the breakers were off.

MR. DAPAS: And so just so I understand. There's been a lot of discussion about what the operators understood is the condition of 2A9 here, and I understand it had damage associated with what the load

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side from 2A9 to A3 and A1, right? What I think I heard you say is, operators -- you would have dispatched relay technicians to do a Megger test and that would have been the extent of the condition for you to determine if 2A9 was in fact available and could be energized from the alternate AC diesel and then power the Unit 2 safely.

MR. HATHCOAT: That's correct. We did that several days after when conditions were stable and it tuned out the Meggers test were good and the breakers were good.

MR. DAPAS: Okay. What I'm hearing from John is that you were confident that that bus was available and those are the actions you would have expected and the operators considered that as an available...

MR. HATHCOAT: Absolutely, sir. And I was in the control room at the time and I followed up and asked each one of them.

MR. MITMAN: This is Jeff Mitman. 2A9 is immediately next to 2A1 if I remember correctly. All right. In 2A1, there was water on the floor on 2A1. So is it safe to assume there was water on the floor in front of 2A9, all right? And the question I'm getting at is, I would think that the staff would be cautious about performing a lot of testing on 4160-volt bus work

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with water on the floor, and that they're going to be hesitant to do that work.

MR. MCKENNEY: The water on the floor was very small and had ran in the back of the one cubicle. So this is next to it. There was some water on the floor in the front and a little bit in the back. All the feeder cables from the alternate AC diesel generator come in the bottom, but it's cables. It's not bus work like this other so, and all the other feeders that go out of it come out the top.

MR. MITMAN: I understand the actual situation, but we're talking about working around energized switchgear at 4,000 volts with water also in the vicinity. We've got a busted fire main that's distributing water places were it's never intended to be water, okay? And I think it's going to slow things down at a minimum.

MR. MCKENNEY: Well, in this particular case we'd be in a blackout and be de-energized, right?

MR. HATHCOAT: Yes. And if I may, I'll try to give a better picture. It wasn't water all over the floor. There was a couple of puddles behind 2A1. The busted fire main was outside the wall in the train bay. It really wasn't in front of the 2A9 switchgear.

MR. MITMAN: I understand, but there was

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enough water and enough problems with 2A1 to keep people away from that bus for hours because they weren't sure what was going on, and there was a reluctance to go in front of the bus and check out cubicles, and which one's damaged and what's the extent of damage? So there's damage on the bus, there's water in the vicinity, we know that water caused the damage on the bus.

I just think there's going to be the reluctance and the caution, which I think is appropriate around this kind of equipment would extend to, at least slow down the normal response that you wouldn't have under more normal circumstances.

MR. BROWNING: And those cautions, again, in my mind I'm trying to see what actually happened. We were protecting that area because we did have energized equipment. In station blackout when the operators get to that step that says go bought the alternate AC generator in, it is de-energized.

Now before we -- whatever we would have done or how we would have approached that would have been a different mindset. When we're in a blackout, it's de-energized and how we approach it would be a different approach than the way we actually approached it the day of the event when we had power on those buses.

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MR. MITMAN: But blackout, as I understand it, is defined as de-energizing the vital buses 2A3 and 2A4. So you could be there with power on 2A1 and 2A2 and no power on 2A3 and 2A4. Again, all I'm suggesting is that there's going to be a little bit extra caution taken when addressing the issue and trying to reenergize the vital buses from the AC diesel generator.

MR. KOWALESKI: We agree, and the probability of failure has been adjusted for that.

MR. DAPAS: That's where I was going to go. I think it might be Jeff's done a very good job articulating the challenges the operators faced here, and what reluctance may exist. If you think, John, you accurately, if you characterize from your perspective how you would approach that. If Jeremy, right, the mindset that exists when you're in a station blackout here.

I think we need to understand how you accounted for that. We'll need to in our internal discussions reach a view on how we should appropriately account for that. But I'd be interested in understanding how you factored that. When it gets to the uncertainty aspect, you know, we're trying to bound liability analysis and how you accounted for that in

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your...

MR. BROWNING: That's absolutely fair.

MR. HATHCOAT: I'll move us along here. We've already talked about the building the cross tie, 2A3 and 2A4 are vital. 4160-volt buses, we have standard attachments and proceduralized and operators would have certainly used it if need be on the day of the event.

So in conclusion, on the Unit 2 side, we've talked about the pretty specific paths that we don't have credit for in the NRC model, and the differences between the NRC model and the ANO model. The Startup 2 availability, alternate AC diesel generator, and ability to cross tie or vital buses.

So in the end, we ended up with four out of five possible power sources were available to the Unit 2 control room that day of the event. We had the resources, the specific training, and the specific procedures to utilize all those power sources if needed, and the confidence to know that we would have been there.

MR. CLARK: Let me ask a question before you go on. This is Jeff Clark. So you lost reactor cooling pumps. Did you go into the cool down?

MR. HATHCOAT: We did.

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MR. CLARK: So that was a natural-circ cool down?

UNIDENTIFIED SPEAKER: That is correct.

MR. CLARK: Is that considered normal for Unit 2?

MR. HATHCOAT: Absolutely not. That is not normal.

MR. KOWALESKI: That is not normal operating procedure.

MR. HATHCOAT: That occurred, not in that post-trip, that occurred after the Startup 2 lockout which caused us to lose our 6900-volt buses.

MR. KOWALESKI: The immediate trip was uncomplicated. 90 minutes later when we lost our [unclear] that's when these additional complications occurred.

MR. BROWNING: Operators re-diagnosed and diagnosed the conditions, this is not normal procedure, so they would, again, if we lost the diesel, they would have re-diagnosed and put us in an appropriate EOP where it's functional or blacked out or whatever.

MR. CLARK: Okay. Thank you.

MR. HARRIS: Let's move on to significance determination. It's getting late in the day, I'm going to move through this pretty quickly. And

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I just want to hit on the very critical points. We looked the at the dominant cut sets that were provided in the NRC assessment for the loss of feed water model, and we looked at what was contributing to that on a sequences we noted that we needed power, okay?

Given that and the discussion that John just provided with you, we looked at 2A2, alternate AC, and the cross tie between 2A3 and 2A4. As John indicated, 2A2 was available. It's a simple matter of pull the lock, procedures in place by operations. Our current model for ANO 2 has a failure to recover that 8.0E-4 because it is in the control room, it's a simple action, not much time taken to do that.

I guess the recovery that's most challenging would be alternate AC and taking credit for that. Model -- we do have a recovery action in the model for the alternate AC. However, because of the issues associated with alternate AC, we felt like we needed to make some adjustments in model to account for these.

And what we did was pretty simply we took out availability on the alternate AC and we applied a 0.1 factor for unavailability to increase that to .17 from the nominal value to account for the fact that the alternate AC did have some issues, it wasn't straight

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forward, it wouldn't, you know -- the operator may have had to take additional time to insure that that particular success path was available.

And the final one, again, is the 2A3/2A4 cross tie capability. Again, it is in our model and we have a value of 2.0E-4 associated with that value.

So when we look at the Unit 2 model because we don't have the NRC model again in this case, we calculated a risk of 1.8E-6 conditional core damage probability for Unit 2.

MR. LOVELESS: I guess this is what I really don't understand. You say you used values that were in your current model. You say you adjusted the probability of failure of the alternate AC diesel up a little bit, and yet in October-September timeframe you provided an analysis that shows CCDP of 3.0E-5, presumably from your current model. What's different?

MR. HARRIS: And I can't answer that question. I'll let Jason respond to that.

MR. HALL: Originally, with the -- we had the two 2A9 unavailable in that analysis. It drove the risk up to 3.0E-5 for the CCDP. And we also credited an operator action for the breakers when they were -- in Startup 2 is being -- could fail, these breakers would cause the Startup 2 transfer to fail. So we credited

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that operator action.

MR. LOVELESS: So you added a new operator action into your model that wasn't there before?

MR. HATHCOAT: Correct.

MR. LOVELESS: And what is that specific action?

MR. HALL: If one of those breakers when you load shed from Startup 2, If they don't --if the breakers fail, an operator will go down and pull, and manually operate the breaker. And there's several breakers. That's included in my analysis for the...

MR. LOVELESS: Okay.

MR. HARRIS: So performing a -- using an insert program, simply using insert, performed a sensitivity analysis surrounding a point estimate we calculated for the Unit 2 results. We determined that 3.9E-07 is the probability for the lower bound and 5.3E-06 for the upper bound.

MR. LOVELESS: What was it that you adjusted for that sensitivity analysis?

MR. HARRIS: That we adjusted -- we ran insert using the point estimate for the additional core damage probability.

MR. LOVELESS: So it's like a Monte Carlo

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simulation?

MR. HARRIS: That's right.

MR. CIRCLE: So you didn't change any values, you just ran the insert program?

MR. HARRIS: That's all we did. That concludes my presentation.

MR. KENNEDY: We're getting ready to transition from risk to some other discussions. I just want to make sure -- we'll have another opportunity, but before we leave the risk, make sure that the senior reactor analyst and these folks don't have any questions before we move on to what is really the non-risk discussion. We'll have another opportunity, you time to think about it. Okay. Not right now?

MR. DAPAS: Just check maybe if we could with the risk analyst who joined us on the bridge. I thought I heard a couple.

MR. KENNEDY: Sunil, Antonio, do you have any comments for us.

SPEAKER ON PHONE: Sunil has -- he left for the day. I don't think that the questions -- I think I'm having questions asking for information from the licensee to give us an understanding of the basis of the calculations. I think those questions have been asked and we will wait for this information and review

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it.

MR. DAPAS: Thanks See-Meng.

MR. JAMES: Okay. I'm going to cover very briefly with you the site actions that we took associated with corrections or improvements to our material handling procedure that dealt directly with the lifting of the stator. And I'll be very brief on that. I think we've covered that in quite a bit of detail already. And also describe in more detail actions that we've taken associated with our project management procedure from the root cause that we saw, enhancements that have been made there to further enhance the oversight of those activities.

And then finally describe the common cause initiative that we have underway that will provide us with some additional insights as well as any additional corrective actions that we could take. That will include a review of the standard op.

Just briefly, out of the stator drop root cause, looking at the activities surrounding the review that was performed associated with the temporary lift assembly. What we saw is there were weaknesses in our procedure -- our material handling procedure Unit A 119. Clearly that procedure could be improved by us providing additional specification for the review and approval of

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design documentation associated with those temporary lift assemblies.

We actually took those lessons learned and applied them in the lift of the refurbished stator that went back into the unit once the construction activity were completed. Included in there were detailed engineering calculation package that documented all that material, which included both the computer modeling of the assembly that was used in that particular application as well as hand calculations, detailed documentation of load testing that was performed.

This particular instance we actually load tested the complete assembly at vendor's facility as it would be constructed in the ANO turbine building at greater than 125 percent of anticipated load. That assembly was then disassembled and shipped to the site where we examined all the critical welds associated with it and then reassembled it in the turbine building with an examination performed by Entergy Engineering at that point in time also.

And then finally, a third-party independent review was performed by an expert that is familiar with all these codes that are applicable to the design of this particular application.

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Basically what we did is include those same requirements now in our procedural requirements and the material handling procedure. Those are all specified in that procedure for these detailed type evaluations will be documented for all future applications of similar nature.

We also revised our fleet procedures associated with project management. What we saw there is that there was enhancements that could be made, particularly with respect to the guidance for contract language. What we are weren't getting is the details that we needed to perform a thorough evaluation. So went into that procedure and verified -- went into that procedure and made modifications to ensure that those type of documentation associated with code compliance, vendor detailed design, calculations were provided, not just for this type of application, but from any applications where that would be necessary for us to perform an independent review.

We also looked at that procedure with respect to its guidance on the makeup of the project management team. When you looked at the particular team makeup for the stator project, what we found is it lacked the expertise necessary to evaluate this type of special application.

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We had individuals on that team with expertise in load handling, large load handling, and expertise with respect to civil engineering, but they didn't have this particular expertise associated with this application.

So what we went and did is went back into that procedure and revised it to specifically look for -- specifically require when we put together one of these project management teams that we go look at these particular applications where high consequence evolutions are occurring as a result of the project and ensuring that the team makeup either has that expertise within the staff or that it requires that expertise through a third party or some other application.

MR. DAPAS: Dale, this is Marc Dapas. I've got a question along those lines where I see that you're looking at verification of a third party, independent review of vendor calculations and I assume that specific to the material handling program --

MR. JAMES: That is correct.

MR. DAPAS: The question I have, more broadly, do you look at -- do you have the expertise inhouse to independently assess the quality of the deliverable products that you're getting from the vendors there because there's other applications where

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you use contractors, use vendors, so did you leverage the learnings from this to look at other processes for which we use contractors to ensure that it's not some issue there that hasn't been identified as a result of appropriate oversight?

MR. KOWALESKI: Maybe I could address that. This is Joe Kowaleski. You could put the engineering work by vendors into two broad categories. One would be engineering work which would effect the design of the plant and plant equipment. And we have a robust procedure that looks at the risks and consequences associated with those activities.

And then it applies a structured set of mitigating actions which include for high consequence items, independent third-party reviews. Sometimes we have that expertise, but more often we'll hire an independent third party to come in and do that type of work.

Where this improves our oversight is for vendor, or more particularly, usually, project specialty vendors that have to do design engineering or engineering calculations in support of project work, such as a special lifter. Now, and there's other examples of that, like a generator bundle.

So this, where we needed to improve this

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was relative to engineering done in support of project activities. And so that's what this is looking at. We've taken some actions with that, which is identification to make sure we've got the expertise. We have an ongoing evaluation to look at applying that engineering procedure to project task engineering as well as design engineering. And that is not is complete yet for the fleet, but we are in the process of doing that.

MR. DAPAS: Okay. Thank you.

MR. JAMES: We also, as part of our corrective actions took an action to reinforce the standards in our -- associated with vendor oversights that are already specified in our EN-DC-114 procedure, our project management procedure.

Followed by that we developed what we call a what it looks like sheet or "WILL" sheet, which is a tool that we use to, basically have the project manager assess those particular aspects out of our project manager procedure that deals with the vendor oversight on the projects that they are involved with. Those documents have been reviewed by the senior project management on site.

One of the things that we saw from the root cause is that we actually, in this particular

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instance, identified the failure of the temporary lift assembly rack, the drop of the stator as a high consequence, low probability event. And we actually based upon that put into place a risk mitigation plan to address that.

Part of that risk mitigation plan included a requirement to do a load test on that assembly. Now the root cause describes how, why that didn't occur, but what we is at that level of decision making we could add another barrier by requiring that those risk mitigation plans be specifically the responsibility of a management level individual within our organization that will be accountable to ensure that the plan is carried out appropriately and fully documented and evaluated to assure the adequacy of those plans. We put that in place also since the root cause was completed.

As far as communicating the lessons learned out, we've had extensive input with INPO. They have provided them the lessons learned so they could communicate that information out to the industry. In fact, Jeremy just recently participated in a web cast to the industry where we discussed the event and the lessons learned, I believe there was over 150 industry participant.

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MR. BROWNING: Actually, it was closer to 200. And the significance of that is IER is coming out on this event. It was very focused on cause and corrective actions and because this event occurred in Arkansas, you can say I'm the primary sponsor of that IER and I'm going to be imposing through INPO actions for the industry to take.

So if I felt it was very important for my peers to understand the significance of the consequence, the importance of the cause, and the understanding of the cause, and then this IER results in industry-wide actions, that they understand the basis for those actions.

So they heard that from me personally through this web cast and there were over 200 hundred participants in the nuclear industry that were on that web cast.

MR. DAPAS: Is that IER capture a contract on oversight? You talked about aspects of that.

MR. BROWNING: It captures everything that we are discussing with you today.

MR. KOWALESKI: There was a second industry operating experience document that comes out -- that is coming out, I think it came out yesterday --

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that more broadly addresses contract oversight in general. So this is specific to this event, but there is one that talks about broad enterprise risk, large consequence to nuclear safety in plant equipment, it addresses other industry that --

SPEAKER: Specifically to the senior level oversight of contract work scope.

MR. JAMES: I'm on slide 97 now. This last month we also initiated an effort to perform a common cause review of conditions that have occurred in this plant over the last 15 months. That included a standard drop event in that, there were seven total conditions that we had them look.

This is being performed by a team of outside analysts with expertise in performing this type of analysis, also with fleet and ANO resources. In addition to looking at those seven specific events, we're also looking back over the last two years at all of our more significant alpha and bravo condition reports to see what additional insights that may give us using trend coding as well as keyword searches of those documents.

We are also looking at the part of the last two years worth of external assessments that have been performed on site both from outside agency and then

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internal assessment reports.

We also were part of that review utilizing interviews of personnel on that evaluation.

MR. DAPAS: You say you were looking for common causes you focused on keyword searches like oversight as example. Can you give a little more context to this common cause factor and how you approached it?

MR. JAMES: Well, particularly when they were using keywords or using trend codes, they were looking for any particular trend code or keyword that was -- occurred more readily then others for looking for a common causal type evaluation. But also with respect to the identified issues out of the seven specific events that they were looking for, looking for those also in any of those other condition reports using the keywords and causal code evaluations.

MR. DAPAS: Were these events that involved mechanical failures, human error, a combination of? Just curious how you targeted those seven.

MR. JAMES: Yeah. They were, I'll give you some examples. They were the overspeed trip of the ultimate AC diesel generator, the bravo decay heat pump breaker failure, the stator drop itself, the flooding barrier leakage issues, and other similar events like

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that.

And also we had them specifically looking for this as part of this evaluation with respect to oversight, and did oversight play a role in any of those events? So we're anticipating getting some good information from that evaluation with respect to oversight specifically also.

That effort should be wrapping up this month and we'll be sharing those results.

MR. DAPAS: I do have a related question and perhaps the team can answer quickly. You mentioned the alternate AC diesel and the speed trip and I know that we put it was a vendor recommendation preventative maintenance associated with a capacitor, am I recalling that correctly?

MR. JAMES: Yes, sir.

MR. DAPAS: The question I have is, you know, we were conducting a risk assessment, going through that process, but I do have a question, it may be for internal discussion here. To what degree was that diesel available given that latent condition that existed and does it have any impact -- we heard extensive discussion about alternate AC diesel and 2A9, et cetera, but I do have a question regarding any overlap such that the reliability of that diesel given

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that latent condition existed because it didn't manifest itself on the actual overspeed trip, right?

MR. JAMES: Yes, sir.

MR. DAPAS: And I, quite frankly, don't recall the timeframes, but I think that's something we need to look at if we haven't already.

MR. KENNEDY: When did the overspeed trip occur? Before the event or after? So it was before March 31st?

MR. BROWNING: And corrective actions.

MR. DAPAS: And, well, any other -- I know we've had some discussions about, you know, we look at this event probability of failure of one, but then we also looked at trying to model this if it occurred at any outage at all. So that's why I wanted to make sure I was able to connect the dots there. I think I've nuked this out, thanks.

MR. MITMAN: Just one quick addition to that. The rules of the road for RP is you don't normally add more than one form of sufficiency. There all evaluated independently. So we have to look at how that applies here, and whether we would be appropriate under our guidance and procedures to combine, normally we don't combine two analysts.

MR. DAPAS: I understand, but it sounds

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like you've implemented corrective actions such that that diesel was available at the time of the event. The issue had been corrected, so we're focusing on plant configuration, equipment availability during the time of the event here, so thanks.

MR. JAMES: That concludes my remarks unless there are any further questions.

MR. KOWALESKI: Everything we just talked about, the site response and the cause analysis and what I was going to address is this last section is fleet learnings, both actions completed and actions that we currently have in progress associated with primarily contractor oversight.

We talked a lot about the safety significance of this in terms of what was the realistic estimate of potential for core damage frequency and we've given you our belief or the best estimate of that.

I don't want that to take away at all the other significance of this event which is the fact that we did have a fatality, we did injure other employees, and we did put the plant at some level of risk. And that should not have happened.

We depend on contractors because of resource leads and for specific skill sets that we as a utility don't have. But we have to have that

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dependence. We are seeing issues, the industry is seeing issues with performance of those contractors. So we have to have in place a robust process of oversight that protects and corrects those errors that a vendor may make before they produce a consequence to the plant or to people.

We are committed to putting such a robust process in place to ensure that this never happens again. I've been involved in the industry for over 30 years and it's the first time a fatality's occurred in any kind of relationship to a plant or multiple plants that I've had oversight of. And it's quite disturbing. You just can't allow it to happen again.

That said, actions completed. We talked about the material handling procedures for the fleet has been changed to reflect the lessons learned that Dale discussed, specifically strengthening controls and documentation of load lifts, calculations associated with this. And we also talked about the project management procedure for the fleet has been modified for specification design documentation requirements for engineering activities to support projects for determining specific expertise for high consequence activities that a project vendor may perform.

And for putting in place a structure that

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defines the oversight for each project given a risk matrix for that project.

Development a risk matrix, identify the high consequences, we've put a structure for oversight plan in place around those consequences to ensure that they're mitigated.

We've met multiple times with members of the fleet to give them the lessons learned associated with this event and contractor oversight. We've made some organizational changes to be more effective with the contractor oversight. Specifically, for major projects, which is where a lot of these high consequence vendor contract design activities occur, we put in place a corporate engineering group to do those risk assessments and help oversee that the mitigation strategies that are put in place for those engineering-related activities and also the non -- engineering related activities in terms of risk.

And we've also added oversight for our maintenance support and site project manager. So we now have director levels and senior managers that are providing oversight of our main support services contractors and all those contractors that are doing minor projects at our sites.

Across the board, we've made improvements

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in the skill assessments of the supplemental supervision that we utilize at the site. So we will assess their skills for being able to implement, hopefully, verifications, peer checks, safety rules, performance rules that we have on the site.

So those skill assessments have been improved by assuring that there's an Entergy presence in terms of [can't hear] for those supervisors and also to have a demonstrated activity that does an assessment of how well they do in observation how well they give feed back to workers to make sure they follow the rules.

MR. DAPAS: Just a follow-up question. This is an application for the entire fleet, right?

MR. KOWALESKI: Yes, these are fleet-wide actions.

MR. DAPAS: Not just Entergy south?

MR. KOWALESKI: That's correct. The entire fleet.

The additional actions in progress. We've initiated a common cause evaluation for contract performance issues. We've started that and completed an initial piece of that, which is a select group of significant contractor issues we've seen on projects.

We have selected a group of the most significant contract, major contract issues we've had.

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We've done a vending exercise to try to determine if there's anything immediate we need to go after reflected at.

What we found is this last action that I'll talk about that we are starting to implement for the fleet. Again, these are in progress, but we're going to complete that common cause evaluation by looking at two years worth of any project-related cause evaluation that we've done. Any project-related commission report that documented an issue with document limitation, we went back to all the alphas and bravos and the cause analysis and specifically looked into oversight and how the projects were managed --

MR. BILL JAMES: Bill James, the project management. Just for clarity we are going to look at all alpha and bravo across the entire Entergy fleet. We are going to then, the conditions found within those conditions reports, we're going to look at them from the vantage point of project management and engineering as well as engineering associated with project management.

Anything in the maintenance contractor or otherwise arena that doesn't have an engineering or project management aspect to it, will go to the maintenance organization who will be participating. So it's going to be across the board looking at all the

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condition reports and the alpha and bravo space that we've had. So we're not going to go back and pick it up in the future. We're going to do it all the first time through.

Objective is to be complete with this summer and then based on the insights, the learnings out of that, that would complement what we've done to date, those will go back into our processes to begin to judge point to preclude something like this from happening to us again.

MR. KOWALESKI: Jeremy is participating on a committee that's looking at contractor oversight law and helping mold the document that was just released, that's going to go through the entire industry for these limitation improvements to contract oversight. So we will have both our Entergy-specific analysis as well as the industry analysis to form future actions.

And the last item. When we did that initial bit, what we identified as the most single impact we've had [coughing] in the past. If we do a good job of identifying the high consequence tasks or risks in our existing project, if we do a good job of identifying what are acceptable mitigating actions to take, what we can improve on is how we validate or provide oversight of the completion of those mitigating

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actions.

Elevating that oversight to a management level and providing more rigor in the documentation validation process. And that's the action that we're going to proceed with implementing through the fleet that we think will have the biggest impact to improve our contract oversight to reduce risk.

MR. BROWNING: So if there's no additional questions, then I do have a few closing comments that I would like to make and -- one of the fears that I had entering this conference was what I stated in my opening comments. In my mind there's a very distinct difference between us trying to establish a reasonable estimate of the risk of core damage as a result of this event. Clearly, we put the plant and the operators in a challenging configuration that we should have never done. That resulted in some level of increased risk and our job is to achieve an accurate assessment of that.

And the distinction between that and what Joe talked about, the actual consequences and the unacceptable consequences that occurred that day, they're real and they're personal to me.

I know where I was Easter Sunday at 7:30. And those consequences are real. And there's a

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commitment to what Joe is talking about and what I'm talking about, too.

Again, the objective of this conference is one in part to make sure you understand that we recognize the significance, and I know from dialoging and based on the feedback that I -- whether it's body language or eyes, I'm not underplaying the significance of the consequence.

I'm not underplaying the challenge that we unnecessarily put our operators on -- the unnecessary challenge that we put on our safety-related equipment and that can never happen again, and make a distinction between what was the actual best assessment of the risk of core damage that was present.

There's a very clear distinction in my mind that there's two different things. And our objective was to present to you, and I know it's additional information, information we haven't provided to you. It's a methodology that we created that needs challenge to make sure we get to that accurate assessment of risk, but it is our best attempt to take the facts that we have, provide you with that information and our methodology and we're open to receive your challenge and feedback on that methodology.

And I do appreciate the opportunity to be

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able to share with you today.
MR. WERNER: This is Greg Werner of the Nuclear Regulatory Commission. We're going to take a break. The NRC is going to leave the room and we are going to get on a conference with our counterparts at headquarters and other areas and caucus. And then we're going to see if we have any additional questions or information that we need to ask before we complete the conference.
So we're going to go to the room next door. Entergy folks, if you guys want to caucus in this room next door, it's also available for y'all if you want to have some internal discussions outside the meeting room.
MR. DAPAS: This is Marc Dapas. For those folks on the phone, members of the public that have patiently been waiting for the opportunity to ask questions, I'll just outline it is our intent to expeditiously reach a determination whether we have any additional questions here. And then I'll be closing the regulatory conference here formally and then open it up for any questions to members of public.
So we'll do our best to reach closure here on any additional questions that we have in relatively short order, seeing as we've been at this for

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five hours.
MR. WERNER: We're estimating about 10-15 minutes probably.
MR. DAPAS: I was reluctant to provide an estimate, but since you -- my goal would be 10-15 minutes.
(Break taken from 5:55 p.m. to
6:25 p m.)
MR. KENNEDY: Let's see, the length of time we were out doesn't reflect the quality of the discussion so, but, I think what does reflect the quality of the discussion is a few questions that we actually have. So we do have two follow-up -- I think it's two follow-up questions.
So, we'll go through those. In addition, we have a number of information requests. What I would propose is that Mike Bloodgood get together with Stephanie and go through those in detail. We think that what we ask for you all will not have to develop, so we think that you should be able to provide us that information sooner rather than later.
MR. KOWALESKI: Is May 9th -- a week from --
MR. KENNEDY: May 9th is, I think --
MR. KOWALESKI: -- close of business next

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Friday, next Friday. I think that'd be good for anything that we've talked about so far.
MR. KENNEDY: And then if something comes up between now and then, just let Greg know and he'll touch base with the folks that requested the information and we'll work through that. Appreciate you, Stephanie and Mike, for documenting those and getting together and make sure we have all the -- I also asked the risk analysts to get together, too, since we want to make sure that we've captured the specific requests.
MR. WERNER: I think Jeff and Mike Bloodgood and Stephanie will get together.
MR. KENNEDY: We had just a couple of questions and Jeff mitt man has the first one regarding the flooding aspect of the event.
MR. MITMAN: This is Jeff Mitman. With the Stator drop, a fire water header was severed and it took a length of time to get the fire water system shut down. And in that length of time it put a certain amount -- quite a bit of water under the basement of the turbine building and some of that migrated over into the aux building. And some of that water ended up in decay heat removal pump fault, and we were wondering if, and if so, how you factored that into any -- into your risk analysis or your review of the risk analysis, and then

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any of the consequences it might have had on -- or impact on that risk analysis?
MR. SULLINS: I'm not familiar with risk analysis details, I'm sorry.
MR. HARRIS: I'm talking with Jeff right now.
MR. DAPAS: I will add one comment. We are, of course, looking at that separately in the context of flooding vulnerabilities, or the context there that they have an impact on this event and response associated with this event.
MR. HARRIS: Okay. I talked to Jason. The analysis associated with the flooding of the default was done as part of a separate analysis versus flooding events. He did not include any information from the impact of that flood in the analysis he performed as part of the Stator drop that we talked about today.
MR. MITMAN: Okay.
MR. KENNEDY: Then if you could hand the remote mic to --
MR. KOWALESKI: When we provide the information we talked about providing we should go ahead and provide an assessment of potential impact.
MR. TINDELL: This is Brian Tindell, the Senior Resident Inspector of Arkansas Nuclear One. How

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did you account for the EALs in your recovery action credit for both Unit 1 and Unit 2?

MR. WERNER: And I think that in particular, he was interested in how the personnel availability, if you went beyond alert would be impacted?

MR. KENNEDY: So you declare site area emergency or a general emergency, in some of these scenarios and you have accountability to deal with, how did you factor that into...

MR. BROWNING: That's a good question. We did consider the availability of resources, and you would have to reach the point beyond set of core damage before you would escalate from the alert so we, in looking at that, we would stay in an alert class for the success paths that were presented today which would keep the resources described.

MR. WERNER: So essentially you would have to do a core uncovery? Is that what you said?

MR. BROWNING: Yes.

MR. DALE JAMES: Yeah, that is correct. Our review looked like it would, before you would be escalating, you would be have to have imminent core recovery.

MR. WERNER: Did that answer your

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question?

MR. LOVELESS: I thought part of the question was that there was that there was a -- if Unit 2 was going towards a site area emergency and station blackout, how would that impact overall safety services?

MR. KOWALESKI: Just a clarification. Are you asking if we need to consider both units into a single significance assessment?

MR. LOVELESS: I was trying to clarify Brian's question.

MR. KENNEDY: Are there scenarios where, you know, in the risk evaluation where personnel availability would be affected because one of the units had declared, you know, site area emergency or general emergency where accountability came into play?

MR. SULLINS: This is Gary Sullins. As described previously, we looked at it from the prospective of Unit 1, the Unit 1 analysis, he considered -- recall that we're dealing with unavailability of electrical distribution equipment within Unit 1. Our start up transformers remained available, so we did not extrapolate to consider a degraded power for Unit 2 or that separate initiating event for blackout.

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MR. WERNER: I think that concludes questions for the caucus. Mark, did you want to make any additional closing remarks?

MR. DAPAS: Yes I do. Thanks. Couple thoughts. One, I really do appreciate the perseverance, patience, and discipline you've exercised here in providing us your perspective in the stator drop events. We've been at it for over five and a half hours here. We've had extensive discussions and a lot of detailed questions, but very important that we reach a full understanding of your perspective. I think as described in one of slides and I think I mentioned this when I opened, the goal is a realistic estimate of risk utilizing the best available information. Because the consequences of our risk determination are significant here.

We're looking at a preliminary red finding, that constitutes high safety significance, that's for Unit 1. Now for Unit 2, a preliminary risk assessment there was a yellow finding which is substantial risk significance.

And, you know, obviously, dependent on the finalization of those risk significance determinations depends on where you are in the reactor oversight process action matrix here and what's the

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degree of regulatory oversight, and when you have a red finding and supplemental inspection 95003 and independent safety factors, so clearly there's a significant resource expenditure by the agency in providing increased oversight here. And a number of actions that you would end up taking should you find yourself in that particular column of the action.

My point in all that is, it's very important that we do all we can as part of our due diligence and independent assessment to arrive at the most realistic assessment of risk significance, and I'll come back to that in a minute.

I really appreciate the perspective provided by Mr. Sullins and Mr. Hathcoat, the Assistant Operations Managers for Unit 1 and Unit 2, respectively. You were in the control room and I think it was particularly valuable for us to hear your perspective there regarding what you were facing, and as we underscored, very important that you look at it in the context of what the operators understood to be the plant condition at the time and what equipment was available and what decisions you would have made because it is challenging when you're looking at it over a year after the fact with information and knowledge we have now and try and determine, okay, you're in a station blackout

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event and you're dealing with an adverse environment here and there's the stress factors associated with that.

And you know, as part of that realistic assessment of risk, with available information adequately considering those factors that come into play when you find yourself in that particular situation. I was very appreciative of the comment you made, Mr. Browning and yourself, Mr. Kowaleski, regarding the consequences of the event here, in recognizing that it was the actual consequences were unacceptable here given the fatality and the injuries that occurred, not withstanding the focus of this conference certainly is the risk significance. And I do appreciate the comments that you shared with us and the actions you're taking regarding oversight of contractors to insure going forward that the behaviors don't translate into a problem where you actually are dealing with a significant issue from reactor safety context.

But let me come back to, for just a minute, this realistic estimate of risk utilizing the best available information. You heard us with our questions. I think one of things we struggle with here is there is no definitive standard for calculating recovery actions for shut down conditions.

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You, I think, did provide us clearly with your perspective regarding methodologies you used and why those were appropriate. And you're correct. We did not give credit for recovery of the 4160-volt bus or inventory control. We're going to go back and look at what you proposed and determine based on our assessment whether that's reasonable here.

I do appreciate the significant time margin you've indicated exists here and that provides some additional, if you will, space to consider uncertainty there. And I do appreciate the perspective regarding the comparison of the normal outage configuration and what's required by the tech specs, comparing that with the plant condition after the event.

I think we struggle, too, with we have definitive guidance when we talk about recovery actions whether they're proceduralized and when there's training here. And when you're talking about Unit 1 here and the different success strategies, you know, the three success paths here that you've presented to us, those weren't proceduralized and trained on in the same context of what our guidance would provide of how we should treat the manual actions, etc., so we'll need to look at that and determine whether what have you have provided us appears reasonable.

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So, next step here, I think we have a clear understanding by virtue of what you presented to us, the basis for your assumptions and how you approached in determining the risk significance. The next step for us is to consider that fully and then we'll communicate the final risk significance to you via a separate correspondence here. I'll offer, if we do have any questions as we're going through that process we won't hesitate to reach out because it's important that we don't have a gap in information here.

So with that, I will close and again thank you for the time and the manner in which you answered our very detailed questions. With that, I'll close the formal portion of the Regulatory Conference and Greg can open it up to entertain any questions from those members of the public that might still be on the phone may have.

Thanks.

MR. WERNER: Thank you, Mark.

Operator, can you go ahead and begin to cue up questions for those on the phone?

OPERATOR SYLVIA: Thank you, we would now like to open the lines for any questions. If anyone does have a question, please hit star-one and record your name when prompted. Again, it's star-one to ask a

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question. One moment to see if we have questions.

MR. WERNER: I'll just provide a quick briefing again, we will alternate between members of the public attending this meeting here in the room, as well as those on the bridge. For both of those in the room and on the phone bridge, please introduce yourself, state your affiliation, and then ask your question or make a comment.

Questions and comments be limited to three minutes at a time. So we'll start with a member here in the room. Are there any members of the public that would like to ask a question. If you'll raise your hand, I'll come to you with the mic. Anybody?

All right. We have no questions here in the room. Operator, do you have any questions from members on the phone bridge?

OPERATOR SYLVIA: I am showing no questions.

MR. WERNER: I understand no questions. We'll just second it one more time. This will be the last chance. Sure no questions? No questions?

Well, that concludes our conference. Again, thank you for your attendance. And as a reminder, members of the public please fill out a public meeting feedback form. There's some on the table over

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here, up against the wall.
And for members of the public on the phone, if you'll go to the public meeting website and look at our announcement, I think there will be a public meeting form that will be automatically populated, I think at midnight tonight, so if you'll go and get that form tomorrow and fill it out and send it to us, we appreciate it.
Thank you very much.

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This is to certify that I, KATHLEEN MCCURRY, a Certified Shorthand Reporter, reported in shorthand the proceedings at the Nuclear Regulatory Conference meeting on May 1, 2014 at 1:00 p.m., and that the foregoing 209 pages contain a full, true and correct transcript to the best of my ability of said proceedings.
Given under my hand and seal of office on this the _____ day of ______________, 2014.

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