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No.	DATE	DESCRIPTION/ (PAGE COUNT)/EXEMPTIONS
5a.	12/31/99	Submittal-Only Screening Review of the Oconee Units 1, 2, and 3 Individual Plant Examination for External Events (Seismic Portion) (29 pages) Exemption 7F
5b.	10/13/99	Review of the Submittal in Response to U.S. NRC Generic Letter 88-20, Supplement 4 (40 pages) Exemption 7F
9.	01/29/07	Summary of Revised Fragility Evaluation Results for Jocassee Dam (67 pages) Exemption 7F
15.	10/01/07	Slides for Final Regulatory Assessment of Oconee Flood Barrier Issue (12 pages) Exemption 7F – already public ML14058A079
19.	05/19/08	G20080334/EDATS: OEDO-2008-0378 - Briefing Package for Drop-In Visit by Duke Energy Chief Nuclear Officer with Chairman Klein and Commissioner Jaczko On May 21, 2008 (20 pages) Exemptions 4* and 6
25.	12/04/08	Oconee Nuclear Station, External Flood NRR Meeting, Rockville, MD, December 4, 2008 (44 pages) Exemption 7F
26.	02/03/09	G20090013/EDATS: OEDO-2009-0009- Briefing Package for Commissioner Lyons Visit to Oconee on February 4, 2009 (31 pages) Exemptions 4* and 6 - already public ML14058A053
46.	03/18/10	Y020100042 - Prepare Briefing Book and Material for Eric Leeds for the Duke Fleet Meeting on March 18, 2010 (23 pages) Exemption 6
59.	09/01/11	G20110617/EDATS: OEDO-2011-0572 - Briefing Package for Visit to Oconee Nuclear Power Plant on September 12-13, 2011

		(25 pages) Exemptions 4 and 6 - already public ML14058A075
62.	01/26/12	G20120048/EDATS: OEDO-2012-0052 Briefing Package for Commissioner Svinicki Visit to Oconee on February 1, 2012 (24 pages) Exemptions 4* and 6 - already public ML14058A076
65.	02/09/12	G20120068/EDATS: OEDO-2012-0066 - Briefing Book – Briefing Package Request for Meeting with Duke Energy on February 16, 2012 (20 pages) Exemptions 4* and 6
69.	07/11/12	07/11/12 Licensee Non-Public Meeting Slides on Oconee External Flood Mitigation (14 pages) Exemption 7F

SUBMITTAL-ONLY SCREENING REVIEW OF THE OCONEE UNITS 1, 2, AND 3 INDIVIDUAL PLANT EXAMINATION FOR EXTERNAL EVENTS

(Seismic Portion)

August 1998
(Updated August 1999)
(Finalized December 1999)

Brookhaven National Laboratory

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LIST OF ACRONYMS

ASW	Auxiliary Service Water
ATWS	Anticipated Transient Without Scram
BNL	Brookhaven National Laboratory
CCW	Condenser Circulating Water
CDF	Core Damage Frequency
DPC	Duke Power Company
EFW	Emergency Feedwater
EPRI	Electric Power Research Institute
GL	Generic Letter
GSI	Generic Safety Issue
HCLPF	High Confidence of Low Probability of Failure
HPI	High Pressure Injection
HPSW	High Pressure Service Water
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination for External Events
ISLOCA	Interfacing-Systems LOCA
LOCA	Loss-of-coolant Accident
LLNL	Lawrence Livermore National Laboratory
LPSW	Low Pressure Service Water
MCC	Motor Control Center
NRC	Nuclear Regulatory Commission
ONS	Oconee Nuclear Station
PGA	Peak Ground Acceleration
PRA	Probabilistic Risk Assessment
RAI	Request for Additional Information
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RLE	Review Level Earthquake
RPS	Reactor Protection System
SEISM	Seismic Event Impact Sequence Model

SRT	Seismic Review Team
SSE	Safe Shutdown Earthquake
SSF	Standby Shutdown Facility
UHS	Uniform Hazard Spectra
USI	Unresolved Safety Issue
UST	Upper Surge Tank

1.0 INTRODUCTION

1.1 Purpose

In response to the U.S. Nuclear Regulatory Commission (NRC) issued Supplement 4 to Generic Letter (GL) 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10 CFR 50.54(f)," Duke Power Company (DPC) performed an IPEEE for the Oconee Nuclear Station (ONS) Units 1, 2, and 3, and submitted the IPEEE results to the NRC. The original IPEEE analysis results were submitted in 1996 [Reference 1]; a Supplemental Report, containing revised analyses, was submitted in December 1997 [Reference 2]. Brookhaven National Laboratory (BNL), as requested by the NRC, performed the submittal-only (1996 submittal and 1997 update of submittal) screening review to verify the technical adequacy of the seismic portion of Duke Power's IPEEE submittal. As a result of this review, the NRC sent a Request for Additional Information (RAI) to Duke Power. Duke Power responded with the Oconee Nuclear Stations IPEEE-Response to RAI in March 1999 [Reference 3]. This Screening Review presents the results and conclusions of the BNL review and evaluation of both the original submittal and the licensee's response to the RAI.

BNL's methodology utilized for the review followed the guidelines provided in the document titled "Guidance for the Performance of Screening Reviews of Submittals in response to USNRC Generic Letter 88-20, Supplement 4" (Draft, October 24, 1996), as amended by the NRC.

1.2 Background

The Oconee Units 1, 2, and 3 are Babcock & Wilcox pressurized water reactors with a rated power of 2568 MWt each. The balance of the plant station was designed and constructed by DPC and Bechtel Corporation designed the reactor buildings. Commercial operation of Unit 1 started in 1973, and the last unit (Unit 3) started in 1974. The site is located in northwestern South Carolina, on the shore of Lake Keowee along the Keowee River, which is a tributary of the Savannah River.

The Safe Shutdown Earthquake (SSE) for the site is 0.10g for rock and 0.15g for soil condition, and the plant is binned in the 0.3g full-scope review category. The site is made up of a shallow soil layer over bedrock. Except for the water storage tanks, the switchyard, and the outside transformers, all the major structures are founded on rock.

The major structures include three reactor buildings, a common turbine building, and two auxiliary buildings, one servicing Units 1 and 2, and the other servicing Unit 3. The emergency power for the ONS is provided by the two units of the Keowee hydroelectric station, which is located at the Keowee Dam, about a mile away from the plant. In addition to the conventional grid network, backup power is also available through a dedicated line from three combustion turbine units at the Lee Steam Station, approximately 30 miles away. The plant design incorporates the Standby Shutdown Facility (SSF), a totally independent means of achieving and maintaining safe shutdown conditions if the normal plant safety systems are unavailable.

1.3 Licensee's IPEEE Process and Licensee's Insights

Duke Power chose the probabilistic risk assessment (PRA) method for the seismic IPEEE analysis. The original IPEEE analysis results were submitted in 1995 without relay chatter evaluation. After the

completion of the relay evaluation in conjunction with the A-46 program, the new revised IPEEE analysis was submitted in 1997. The methodology adopted by the licensee has features similar to most other seismic PRA IPEEE analyses, i.e., use of uniform hazard spectra (UHS), aggressive screening approach, use of surrogate elements, and reasonably good walkdowns.

New structural response analyses were not conducted for the submitted IPEEE seismic analysis. Instead, the component fragilities were re-evaluated by utilizing the earlier seismic PRA results in 1984, which used the NUREG/CR-0098 rock spectrum for the ground motion input at the bedrock. The old component fragility values were revised using the spectral ratios of Electric Power Research Institute's (EPRI's) median UHS at a 10,000 year return period to the NUREG/CR-0098 spectrum. The seismic walkdowns were conducted by personnel from Duke Power and EQE, in conjunction with the A-46 program. The component screening was performed based on a screening criterion of 0.3g high confidence of low probability of failure (HCLPF) capacity.

In the risk quantification, a seismic event tree was developed with a total of 11 seismic top events (seismic initiators), including interfacing-system loss-of-coolant accident (ISLOCA), large LOCA, medium LOCA, and reactor coolant pump (RCP) seal LOCA. In the 1995 IPEEE submittal, two surrogate elements were used, i.e., the Auxiliary Building Surrogate for anchorage failures of electric cabinets (median = 0.34g) and SSF Surrogate (median = 0.48g), which dominated the calculated core damage frequency (CDF) values. In the 1997 Supplemental Report, these surrogate fragilities were raised to 0.48g and 0.60g, respectively, after completion of the A-46 anchorage evaluation, and three new surrogate elements, i.e., for relay chatter, Keowee station components, and turbine building components, were added.

The calculated mean CDF values for the mean EPRI hazard curve was 3.6E-05/yr for all the units, which was 59% of the total external event CDF of 6.1E-05/yr in the 1995 IPEEE analysis. This value was slightly lowered to 3.47E-05/yr in the 1997 Supplemental Report. The dominant contributors in the 1995 analysis were SSF Surrogate (25%), Auxiliary Building Surrogate (23%), and flooding due to seismically-induced failure of the Jocassee Dam. In the 1997 Supplemental Report, after the elimination of the Auxiliary Surrogate, the SSF Surrogate, and the dam failure were the dominant contributors.

2.0 REVIEW FINDINGS

2.1 IPEEE Format and Methodology Documentation

The submittal appears to be consistent with the guidelines of NUREG-1407. The study addressed most of the issues that are emphasized in NUREG-1407, including plant walkdowns, soil liquefaction, relay evaluation, nonseismic failure, human actions, and containment performance. A comprehensive relay chatter evaluation, as required for full-scope plants, was conducted in conjunction with the A-46 program, which was on-going in parallel with the IPEEE seismic analysis. Regarding the completeness of documentation, the seismic portion of the submittal provides only an outline of the analysis. Descriptions of the walkdown findings, the component lists, and the structural response analysis are not provided in the submittal.

2.2 Seismic Review Team Selection

The seismic review team (SRT) consisted of personnel from Duke Power with assistance from their consultants, EQE International. The peer review team was also formed with personnel from the same organizations. The review comments and the resolutions were provided in the submittal. It appears that the SRT selection meets the NUREG-1407 objectives.

2.3 Hazard Analysis

The study used the EPRI seismic hazard curves which were cut off at 1.02g. A sensitivity analysis was performed by extrapolating the hazard curves to a 1.5g level. The result indicated only a minor increase in the CDF value, from 3.6E-5/yr to 3.7E-5/yr. Another sensitivity study using the 1989 Lawrence Livermore National Laboratory (LLNL) hazard curves was also performed, but the results of the additional analysis were not described in the submittal. The median UHS at a 10,000 year return period based on the EPRI study was used to revise the old fragility values, which were based on the NUREG/CR-0098 spectrum. The fragilities corresponding to the UHS were determined by modifying the existing fragilities using a multiple mode scaling method, which is further discussed in Section 2.6.

2.4 Components Selection

The submittal does not provide any component listing, but briefly describes the component screening procedures. According to the 1995 submittal, the EPRI NP-6041 screening criteria at a 0.8g spectral acceleration level were used. The licensee's RAI response further described that the peak ground acceleratioin (PGA) value that corresponds to the EPRI NP-6041 screening criteria at 0.8g spectral acceleration level is interpreted by DPC as being defined on the ground surface relative to the bedrock motion for a rock site. The licensee further states that components screened out on the basis of walkdown using the above interpretation of the EPRI NP-6041 can then be stated to have a $HCLPF_{50}$ of 0.3g PGA or greater ($HCLPF_{50}$ stands for HCLPF value computed assuming the ground motion is defined at 50^{th} percentile level).

2.5 Plant Walkdown Approach

The walkdowns were conducted by personnel from Duke Power and EQE in conjunction with the A-46 program based on the criteria in EPRI NP-6041. The issues addressed in the submittal included the seismic spatial interaction, seismic induced flooding, and seismic fire interaction. The equipment inside containment for each unit, as well as a total of 1,800 relays, were walked down according to the 1995 submittal. Detailed descriptions of the walkdown findings were not provided, as no component lists were included in the submittal.

2.6 Fragility Analysis

2.6.1 Structural Response Analysis

As already discussed in Section 2.4 of this report, a NUREG/CR-0098 median spectrum anchored at 0.18g at the top of rock was used as the review level earthquake (RLE) in the IPEEE analysis. No information was provided on the corresponding free-field ground motion. The submittal does not provide any technical bases

for the statement regarding this selection of RLE, i.e., "this corresponds to a 0.3g free-field acceleration as recommended in NUREG-1407."

The licensee provided a more detailed description of the fragility analysis in their RAI response, which is summarized below.

All major safety related structures at Oconee are founded on bedrock, and the EPRI and LLNL seismic hazard studies considered the Oconee site as a rock site and did not model the shallow overburden soil. The fragility analysis was performed assuming the ground motion defined by NUREG/CR-0098, anchored to 0.18g at the bedrock. It is immaterial in development of the fragilities what the PGA at the site is, since the capacity is defined as some multiple of a reference PGA to which the ground motion spectrum is anchored.

For equipment mounted on pads at grade or on the basemat of surface founded structures, the input motion was developed by convolving the UHS rock spectrum through the soil column. Therefore the HCLPF calculations for the surface founded equipment were also based on the UHS rock spectrum anchored at 0.18g. This approach seems acceptable.

2.6.2 Structural Fragility Analysis

In the 1997 Supplemental Report, all the structures were screened out except the auxiliary building frames (median = 1.29g) and masonry block walls (median = 1.34g). The fragility values for these structures were obtained by revising the old fragility analysis results using the "UHS scaling factor." The issue of the scaling factor is further discussed in the following subsection.

2.6.3 Component Fragility Analysis

In the 1997 IPEEE analysis, many changes were made in both the selection of components included in the seismic analysis and the fragility values, after the completion of the A-46 program. In addition to the two surrogate elements, i.e., Auxiliary Building Component and SSF Component Surrogate, three new surrogate elements were added. However, the above mentioned bases of fragility evaluation, i.e., the use of old fragility analysis results, use of the NUREG/CR-0098 spectrum, and the use of the "UHS scaling factor," appear to be unchanged.

According to the licensee's RAI response, the seismic PRA analysis was performed using the site-specific UHS defined at the bedrock. To convert the existing fragilities developed using the NUREG/CR-0098 spectrum to the UHS based fragilities, a scaling method developed by DPC was used. The DPC scaling method is different from the scaling method outlined in EPRI NP-6041. The scaling procedure described in EPRI NP-6041 is based on the ratio of the two ground motion spectra at a single dominant frequency and may not be appropriate if the structures have significant response in many modes and the shapes of the ground motion spectra are significantly different. The DPC scaling method is developed on a mode-by-mode basis to account for the multi-mode response. Furthermore, all major structures at Oconee are founded on bedrock. There is no equipment mounted above the basemat of the surface founded structures. For equipment mounted on pads at grade or on the basemat of the surface mounted structures, the scaling factor was developed by comparing the NUREG/CR-0098 and UHS ground motion spectra at 8 Hz, which is the frequency of the soil column above bedrock. The surface motions were generated by performing convolution analysis using the SHAKE program. Table 1 in Section 3 of the licensee's RAI response summarizes the guidance on the scaling approach that was incorporated into the Oconee fragilities.

2.7 Soil Evaluation

Some of the safety-related equipment is founded directly on the surface of the shallow soil layer, including Transformer CT-4, Blockhouse, Borated Water Storage Tank, Main Start-up Transformer, Condenser Circulating Water (CCW) Piping, Relay House, and Switchyard. According to the 1995 submittal, soil liquefaction was addressed by reviewing the existing geotechnical studies, and concluded that no concerns were found for liquefaction.

2.8 Relay Chatter Evaluation

As part of the A-46 program, a total of 6147 relays were reviewed for the entire plant according to the 1997 Supplemental Report. The overhead power path relays were found to have low fragilities and were included in the analysis as a surrogate element. A total of 142 other low-ruggedness relays were listed for further analysis or replacement.

2.9 Containment Performance

Containment performance is discussed in Section 3.1.6 of the IPEEE submittal. Important issues raised in NUREG-1407 are addressed in the IPEEE.

Containment structure integrity, containment isolation, and containment safeguards were evaluated in the IPEEE. Containment isolation signals and the effect of relay chatter were also evaluated. Walkdowns on containment performance issues were conducted inside the containment for each unit (Section 3.1.2.3 of the submittal).

According to the IPEEE submittal, the equipment and structures required for containment performance have been examined. The potential failure modes, and the consequence thereof, have been examined.

2.10 Nonseismic failures and human actions

The fault trees developed in the Oconee Seismic PRA consist of events for both seismic fragility related failures and nonseismic failures (including random failures of components and unavailability of the components due to test or maintenance). Failure probabilities for nonseismic failure events are presented in Table 3-2 of the IPEEE submittal (December 28, 1995) and Table 2-2 of the Supplemental Report (December 18, 1997). A 24-hour mission time is used in the IPEEE for CDF calculation.

The probability values used in the IPEEE for human failures are also presented in the above tables. The bases for the values used in the IPEEE are not provided in the submittal or the Supplemental Report. They are discussed in the licensee's response to the RAI (Seismic Question 2).

According to the RAI response, of the sixteen human error events in Table 2-2 of the Supplemental Report, eleven were documented in the Oconee PRA report, two were added in the 1995 IPEEE submittal, and an additional three were added in the 1997 Supplemental Report (reflecting the changes made to the fault tree logic as a result of the relay chatter reviews). Methods used for obtaining the probability values are discussed in the response. Detailed discussions are provided in the response for some of these events (e.g.,

events that do not have sufficient plant procedures in place and events that involve operator actions out of the main control room).

2.11 Seismic-Induced Fires/Floods

Seismic-induced fires are discussed in Section 4.8.6 of the IPEEE submittal. Walkdowns were performed to identify the potential for fire ignition, propagation, or increased fire hazard due to damage to equipment or components in a seismic event. For those identified items that could not be screened based on their location relative to important safety equipment, more detailed analysis was performed. The potential for fire protection system water piping failure during a seismic event was also investigated as part of the seismic walkdowns (independently by both the seismic review team and the fire review team).

Procedural and physical improvements to the plant resulting from the fire/seismic interaction review are presented in Section 4.9 of the submittal as part of the overall improvements from the fire analysis.

To address the flooding issues, the potential for ruptured vessels or piping that could spray, flood, or cascade onto essential equipment in vulnerable areas of the plant was examined in walkdowns (Section 3.1.2.3). The fault tree models used in the seismic analysis include the effect of both internal and external flooding sources (Section 3.1.5.2).

The examination of seismic-induced floods and seismic/fire interactions performed in the IPEEE and the discussion provided in the submittal seem adequate.

2.12 Logic Models

Logic Models: The method used in the Oconee seismic analysis is similar to the "Zion Method" discussed in the PRA Procedures Guide (NUREG/CR-2300). An event tree is first developed to identify possible core-melt sequences. Fault trees are then developed for the various event tree sequences to determine and quantify the various possible accident scenarios (cut sets).

The event tree used in the seismic analysis is presented in Figure 3-2 of the submittal. Top events considered in the event tree include: (1) Seismic Event Affects The Oconee Site; (2) Reactor Protection System Trips Reactor; (3) Reactor Coolant System (RCS) Overpressurization Prevented; (4) Unisolable ISLOCA Does Not Occur; (5) Large-Break LOCA Does Not Occur; (6) Medium-Break LOCA Does Not Occur; (7) Secondary Side Heat Removal Maintained; (8) RCS Relief Valve Reseats After Opening; (9) RCP Seal Integrity Maintained; (10) Safety Injection Established, and; (11) Long -Term Cooling Established. Seventeen core damage sequences were identified from the event tree. Fault trees were developed for each of the 17 sequences for sequence quantification.

Fault trees are presented in Appendix A of the IPEEE submittal. Updated fault trees that include additional information obtained from relay review and other enhancements are presented in Appendix A of the Supplemental Report to the original IPEEE submittal (December 18, 1997). Basic events included in the fault trees and their failure probabilities are presented in Table 3-1 of the original IPEEE submittal for seismic fragility related failures and in Table 3-2 for nonseismic and operator failures. Updated values are provided in Tables 2-1 and 2-2 of the Supplemental Report for the seismic and nonseismic related basic events, respectively.

According to the fault tree models, seismically-induced failure of a system can be due to failure of its components, failure of its support systems, or failure of major structures such as the auxiliary building, the condenser, the Intake Canal East Dike, the Jocassee Dam, or the Keowee Dam. The condenser hotwell provides long-term emergency feedwater (EFW) water supply. Its failure will result in the loss of the EFW water supply and a flooding of the turbine building causing the failure of the EFW pumps and the service water pumps. The failure of the Jocassee Dam will cause a plant-wide flooding and thus the failure of most, if not all, of the plant safety systems.

At Oconee, the two Keowee hydro units, not emergency diesel generators, provide emergency power to all three units during accident conditions. A seismically-induced failure of the Keowee Dam (with a HCLPF of 0.2) will divert water from the hydro station and fail the emergency power from Keowee quickly. The power from the Keowee Hydro Station can also be lost due to seismically-induced failure of the Keowee control boards (with a HCLPF of 0.22), batteries (HCLPF 0.18), or motor control centers (MCCs) (HCLPF 0.21). Backup power can also be obtained from the Lee Station which has combustion turbines.

In addition to the loss of the Keowee Station and the failure of transformers, buses, or switchgears, power can also be lost if the Jocassee Dam (HCLPF 0.15) fails and floods the site, or if some components in the turbine building or auxiliary building fail. The latter are represented by the Turbine Building Surrogate (HCLPF 0.3) and the Auxiliary Building Surrogate (HCLPF 0.24).

The safety systems considered in the Oconee model include the high pressure and low pressure injection systems in both the injection and recirculation modes, and the EFW system for secondary cooling. The EFW pumps take suction from either the upper surge tank (UST) or the condenser hotwell. The failure of the UST is not modeled in the seismic analysis because the estimated fragility is high (median fragility greater than 2 g). In the seismic model, EFW is assumed to be lost if there is a seismically-induced failure of the condenser hotwell (HCLPF 0.18g) or hotwell pumps (HCLPF 0.23g). EFW can also be lost if there is a seismically-induced failure of condensate coolers (HCLPF 0.15g) due to flooding of the EFW pumps.

In addition to the above systems, the Oconee plant also has a SSF shared by the three units to provide Reactor Coolant Makeup to the reactor coolant pump seals and Auxiliary Service Water (ASW) to the steam generators for secondary cooling. The SSF can be supported either by the emergency power or by its own diesel generator. Suction for the SSF ASW pump is from the north line of the Unit 2 buried CCW (CCW) inlet piping. Failure of the Jocassee Dam (HCLPF 0.15g) can fail the main feedwater and emergency feedwater system, as well as the SSF if the resulting flood height exceeds the 5 foot flood barriers located at its two entrances.

In addition to the electrical power system and the SSF, important support systems considered in the model include the CCW system, the Component Cooling system, the High Pressure Service Water (HPSW) system, and the Low Pressure Service Water (LPSW) system. The service water systems provide cooling to the safety system pumps and the component cooling system, which in turn provides thermal barrier cooling to the RCP seals. Both the HPSW and the LPSW pumps take suction from the CCW system. Failure of the intake canal east dike will cause the lake water to drain away from the CCW pump suction, failing all CCW flow and, consequently, the service water systems.

Surrogate components are used in the seismic analysis for auxiliary building components (HCLPF 0.24, including the effect of screened out relay components in all areas except the overhead path), turbine building

components (HCLPF 0.30g), SSF components (HCLPF 0.30g), Keowee Station components (HCLPF 0.30g), and relay chatter for overhead power path (HCLPF 0.22g).

In general, the logic models used in the IPEEE seem adequate.

Initiating Events: As discussed above, a single event tree, with the seismic event as the initiating event, is used for sequence description. However, for the sequences developed from the event tree, the events considered in the seismic analysis model include seismically-induced LOCAs, anticipated transient without scram (ATWS), ISLOCA, and other transients.

The hazard curves for PGA used in the analysis are based on the EPRI seismic hazard analysis results and are presented in Figure 3-1 of the IPEEE submittal. A sensitivity analysis using LLNL results is not provided. According to NUREG-1407, Section 3.1.1.2, "the staff prefers that mean (arithmetic) hazard estimates from both the LLNL and the EPRI studies should be used to obtain two different point (mean) estimates. If a licensee elects to perform only one analysis, it should use the higher of the two mean (arithmetic) hazard estimates." The Oconee IPEEE submittal does not indicate whether a comparison using the LLNL hazard curves was performed.

Data and Quantification: Failure probabilities for the basic events used in the Oconee seismic analysis are provided in Table 3-1 (for component fragilities) and Table 3-2 (for nonseismic failures and human actions) of the individual plant examination (IPE) submittal. Updated values are provided in Tables 2-1 and 2-2 of the Supplemental Report. The derivation of component fragilities are discussed in Section 2.6 of this evaluation report.

According to the submittal, the fault trees were solved using the CAFTA computer code. The resulting cut sets were reviewed and edited to remove invalid cut sets from the solution. They were then loaded into the SEISM (Seismic Event Impact Sequence Model) computer code for CDF quantification. The SEISM methodology is similar to the "Zion method" described in the PRA Procedures Guide. The only difference is that whereas the Zion method uses a discrete-probability-distribution technique, SEISM uses Monte Carlo simulation.

Although not discussed in the submittal, correlation of seismic failures seems to be considered in the development of the fault tree models.

Hazard curves used in the Oconee seismic analysis are based on the EPRI study. They were developed up to an acceleration level of 1.02g. A sensitivity study extending the curves to 1.5g (by extrapolation) was performed and showed negligible effect. As noted above, the use of the LLNL hazard curves and their effect on the quantification results are not discussed in the submittal.

2.13 Accident Frequency Estimate

Seismic CDF results are discussed in Section 3.1.5.4 of the submittal and Section 5.0 of the Supplemental Report. The calculated CDF presented in the Supplemental Report is 3.47E-5/yr (3.59E-5/yr in the IPEEE submittal). Dominant cut sets obtained from the seismic analysis, their percentage contributions to the total CDF, and the frequency contributions from various acceleration levels are presented in Table 5-1 of the Supplemental Report. The table shows that a flooding event (attributed to the seismically-induced failure of the Jocassee Dam) with a flood level higher than the 5 feet SSF flood barriers makes up the most dominant

cut set (2.41%). This is followed by a cut set with the total loss of power (i.e., from offsite power, the Lee Station, and the Keowee hydro station) and SSF Surrogate failure (1.18%), a cut set with failure of both Auxiliary Building Surrogate and SSF (1.17%), and a cut set with the failure of the Jocassee Dam and the SSF Surrogate (1.09%).

Sensitivity studies were conducted in the IPEEE to determine the effects of some basic events on the calculated results (Section 5.2 of the Supplemental Report). The basic events that are selected for the sensitivity studies include the fragilities of the Auxiliary Building Components Surrogate, Surrogate for Relay Chatter Failing Overhead Power Path, Seismically induced Failure of Jocassee Dam Floods Site, Seismic Failure of Keowee 600V ac MCCs 1XA and 2XA, Seismically-Induced Failure of Keowee Batteries, and SSF Component Surrogate, and the probability value that a Flood Level Exceeds the 5 foot SSF Flood Barriers.

In the sensitivity study, the median fragility values for the selected basic events were raised from 30% to 100%. The changes in the CDF, from 2% to 12%, do not seem to be significant. However, the effects of lower fragility values were not investigated in the sensitivity study.

It is assumed in the base case analysis that there is a 40% probability that the flood level caused by the Jocassee Dam failure will exceed the 5 feet SSF flood barriers. The flood level is important because it determines whether the SSF is available to prevent a core damage accident after all other systems are failed by the flood. According to the sensitivity analysis, an assured failure of the SSF in a Jocassee Dam failure will increase the CDF by 18%, and a lower probability of 10% will decrease the CDF by 9%.

Summary information, such as the contributions from various accident sequences and dominant contributors (e.g., all cut sets with Jocassee Dam failure) to the total CDF are not provided in the 1997 Supplemental Report. It is provided in Table 3-6 of the 1995 IPEEE submittal (based on 1995 results) and the licensee's response to the RAI (Seismic Question 3) based on 1997 updates. According to the response, the leading sequence is a sequence with the loss of RCP seals and coolant injection (67% of total CDF). This is followed by a sequence with seismic-induced ATWS and a subsequent failure of high pressure injection (HPI) (11%), a sequence with seismic-induced large break LOCA and failure of LPI in the injection phase (9%), and a sequence with the loss of secondary cooling, failure of RCP seal cooling, and failure of HPI in the injection phase (6%).

2.14 Dominant Contributors

According to the RAI response, cut sets that include seismically-induced failure of all ac power, coupled with a loss of the SSF (from all causes), make up roughly 70% of total CDF; cut sets involving the SSF (both seismic-induced and independent failures) contribute approximately 72% to the seismic CDF; and cut sets involving auxiliary building and SSF Surrogates contribute 5% and 30%, respectively.

The RAI response also notes that, as indicated in Table 5-2 of the 1997 Supplemental Report, several sensitivity studies were performed on the seismic results to determine the effect of various factors, components and fragilities. The response further states that the results provide several insights, but the only insight provided in the response is that while no one failure truly dominates the results, the sequences involving station blackout as well as SSF failure make up the majority of the seismic CDF.

2.15 Unresolved Safety Issues (USIs) and Generic Safety Issues (GSIs)

<u>USI A-45</u> Shutdown Decay Heat Removal Requirements

This issue was examined and considered to be closed by the licensee. This is discussed in Section 3.2 of the 1995 submittal.

<u>GSI-131</u> Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System Used in Westinghouse Plants

This issue, "potential seismic interaction involving the Movable In-Core Flux Mapping System", applies to Westinghouse plants, and therefore, is not applicable to Oconee.

<u>GSI-156</u> Systematic Evaluation Program

The seismic-induced settlement of foundation is not an issue for the ONS because all the major structures are founded on rock; the potential dam failure was included in the seismic analysis; the seismic design of structures, systems and components was addressed in the 1995 submittal.

<u>GI-172</u> Multiple System Response Program

GI-172 issues were addressed as follows:

- The effects of fire protection system actuation was addressed in Section 4.8.6 of the 1995 submittal. Possible improvement, such as replacement of sprinkler heads, is discussed in section 4.9.

- Seismic/fire interactions were addressed in Section 4.8.6 of the 1995 submittal. Possible plant improvement is discussed in Section 4.9.

- Hydrogen line ruptures are not explicitly mentioned in the submittal, but Section 4.8.6 of the 1995 submittal states that investigating the potential for a seismic event to cause a fire included "....locating flammable or combustible gas piping and equipment containing more than 5 gallons of combustible or flammable liquid. Where these were identified, a more detailed analysis by the fire IPEEE team and seismic margins walkdown team was performed."

- Seismic-induced flooding was addressed in the seismic analysis (Section 3.1.2.3 of the 1995 submittal). The fault tree models used in the seismic analysis include the effect of both internal and external flooding sources (Section 3.1.5.2 of the 1995 submittal).

- Seismic-induced spatial and functional interactions were addressed as part of the walkdown procedures (Section 3.1.2.3 of the 1995 submittal)..

- Seismic-induced relay chatter is discussed in Section 2.8 of this review report.

- Failures related to human errors were considered in the seismic analysis (Section 3.1.5 and Table 3-2 of the 1995 submittal, Table 2-2 of the 1997 Supplemental Report, and the RAI response to seismic question 2).

2.16 Vulnerabilities/Plant Improvements

The 1995 submittal states that, while seismic events are the most significant external event contributors to core damage risk, "there are no unduly significant sequences (vulnerabilities) from external events. No other mention of vulnerability is found in either the 1995 submittal or the 1997 Supplemental Report.

However, several enhancements were recommended as a result of the seismic reviews. A large number of plant improvements are listed in Table 6-1 of the 1997 Supplemental Report, as well as the status of the proposed improvements. (A copy of Table 6-1 is attached at the end of this report.) In addition, a total of 142 low-ruggedness relays are listed in Table 3-1 of the 1997 Supplemental Report for possible replacement.

The contribution of the Auxiliary Building Surrogate to the total CDF depends on the status of the 142 low-ruggedness relays listed in Table 3-1. The contribution may increase if the fragilities of some of the relays cannot be raised above that of the surrogate element. According to the licensee's response to the RAI (Seismic Question 4), to date capacity issues for 59 relays have been resolved by additional analysis and/or testing, 6 relays have been actually replaced in the field, with an additional /14 awaiting implementation. Additionally, several other relay modification design packages are in progress, and additional relay testing is being conducted in an effort to resolve additional outliers. A schedule for resolution of these relays (both USI A-46 and the IPEEE relays) has been developed. Plans are to complete resolution of all outliers, including the relays identified in Table 3-2 of the 1997 Supplemental Report, by the end of 2002. It is the licensee's intention to assure the final fragilities for these relays to be at or above PRA modeled values by testing, analysis, or replacement modifications. In the event this is not the case, the risk impact of the individual fragilities will be assessed by the licensee using the seismic PRA model.

3.0 OVERALL EVALUATION AND CONCLUSIONS

The submittal appears to be consistent with the guidelines of NUREG-1407 as well as GL 88-20 in applying seismic PRA methodologies. The study addressed most of the requested issues, including plant walkdowns, relay chatter evaluation, human action, seismic-induced fires and flooding, and containment performance.

A large number of potential plant improvements were identified.

Based on the IPEEE submittal, the Supplemental Report and the licensee's responses to the RAIs, it appears the licensee has met the objectives outlined in the GL.

4.0 REFERENCES

[1] Oconee Nuclear Station USI A-46 Seismic Evaluation Report (Partial Submittal), Attachment to Letter dated December 30, 1996 from J. W. Hampton, Site Vice President, Oconee Nuclear Station, Duke Power, to the USNRC.

[2] Oconee Nuclear Station Individual Plant Examination of External Events, Attachment to Letter dated December 18, 1997 from W. R. McCollum, Jr., Site Vice President, Oconee Nuclear Station, Duke Power Company, to the USNRC.

[3] Duke Energy Corporation, Oconee Nuclear Station IPEEE Responses to NRC RAI, Attachment to Letter dated March 31, 1999 from W. R. McCollum, Jr., Site Vice President, Oconee Nuclear Site, Duke Power Company, to the USNRC.

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
1&2POWDEXPANEL	Powdex Panel	Remove misc. loose items from cabinet floor. Install clip restraints for fluorescent lights inside of cabinet and mounted to front hood.	TB	
1,2,3 ICS CAB	Integrated Systems Logic Cabinet	Add hard washers to anchors.	AB	
1,2,3 RPS	Reactor Protection System	Add hard washers to anchors.	AB	
1,2,3ESFAS	Engineered Safeguards Cabinet	Add hard washers to anchors.	AB	
1ADB	Isolation Diode Assembly	Add washer plates to the three north anchors of 1ADB.	AB	
1AT3	Area Termination Cabinet	Bolt 1AT1,2,3 & 4 together.	AB	
1B,1A & 1D	Pressurizer Heater Panels	Replace missing door latch on PPB 1B and adjacent PPB 1A & 1D.	RB	
1CR-FRAME	Cable Room PBB frame	Add brace to unistrut frame supporting PPBs in the cable room.	AB	
1CTK000C	Upper Surge Tank Dome Tank	Detailed analysis of column supports or structural enhancements required.	TB	
1DCA	Distribution Center A	Replace back right anchor for 1DCA.	AB	
1DCB	Distribution Center B	Repair compartment latch on 4E.	AB	
1EB1-1EB8	Electrical Boards	Perform in-situ modal testing	AB	
1EB8	Electrical Boards	Remove 1EB8 and add side panel to 1EB7.	AB	
1EHC1,2,3	Electric Hydraulic Control Cabinets	Repair loose anchor in 1EHC's.	AB	
1EHTC1	Electric Hydraulic Terminal Cabinets	Add compressible material between1EHTC1 and adjacent EHC cabinets to prevent impact.	AB	
1EPSLP1	Emergency Power Switching Logic Panels	Relocate 4" cable tray spanning between 1AT2 and 1EPSLP1	AB	
1ES/ICS/AUX	ESFAS,ICS & Aux. Cabinets	Add hard washers to anchors.	AB	
1ESFAS	Engineered Safeguards Cabinet	Add padding between ICS,ESFAS & ES/AUX/ICS cabinets and adjacent column and file cabinet.	AB	
1ESTC2	Engineered Safeguards Cabinet	Add mounting screws to relay.	AB	Completed

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
1ESTC3	Engineered Safeguards Cabinet	Bolt 1ESTC3 to adjacent 1RCP1A cabinet.	AB	
1KESP	Keowee Emergency Start Panel	Bolt to 1MTC	AB	Resolved Analyticaly
1KRB	PPB 1KRB	Repair loose capacitor	AB	Completed
1KX	PPB 1KX	Tighten unistrut bolt in frame supporting PPB	AB	Completed
1LC1,1LC2,1LC3,2LC1,2LC2,2LC3	Logic Cabinets	Enhance support for Keowee Control Room Ceiling. Add padding between cableway and 1LC1 at North end or restrain cabletray. Secure ladder on South side of 1LC3.	Keowee	Completed
1MSVA0129	Main Steam Valve 129	Remove the attached air line and support it from the wall per B31.1 requirements.	TB	
1PRVA0008	RB Hydrogen Purge Inlet Valve	Add stress loop to air line going to 1PRVA0008.	AB	
1RCPS0364	Reactor Coolant pressure Switch	Replace missing screws in component	RB	Completed
1SGFP	Steam Generator FWP Panel	Add mounting screw to non-SSEL Rochestor device inside panel	TB	Completed
1SGLC	Steam Generator Logic Cabinet	Replace existing washer plates with thicker ones.	AB	
1TC	4160 Switchgear	Relocate ladder rack at column K26. Restrain "Chemistry Spill Control Tanks" @ J26.	TB	
1TC,1TD,1TE	4160 Switchgear	Restrain fluorescent bulb fixture at XFMR 1X12. Restrain or verify seismic adequacy of fluorescent bulbs in overhead fixtures.	TB	
1UB,VB AB's	Unit, Vertical & Auxiliary Boards	Enhance existing anchorage to meet IPEEE.	AB	
1UB2	Unit Board 2	Drawing stick sets located behind 1UB2 need to be relocated.	AB	
1X XFMR, 2X XFMR, 1E XFMR, 2E XFMR	600 VAC SWGR Transformer	Add lock washers to Core Coil base	Keowee	In Progress
1X04	Load Center 1X04	Weld transformer section of Load Centers 1X04 to embedded angle.	TB	
1X09	Load Center 1X09	Add shims under load center at anchors on North side and retorque anchors.	AB	
1X10/XFMR	4160v to 600v XFMR	Add clip angles to to restrain transformers 1X10.	TB	
1XA	MCC 1XA	Bolt 2 south bays of 1XA back to back.	TB	
1XA(KEO),2XA(KEO)	600 VAC MCC'S	Enhance existing anchorage for 1XA (KEO), 2XA (KEO).	Keowee	Analytically Resolved
1XC	MCC 1XC	Add back to back bolting to 1XC.	TB	

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
1XGB	MCC 1XGB	Add back to back bolting to the 3 South most bays. Enhance existing anchorage. Restrain or verify seismic adequacy of fluorescent bulbs in overhead fixtures on West side of 1XGB or seismically qualify. Add restraint to adjacent 55gal. trash can.	TB	
1XI	MCC 1XI	Add padding or brace 1XI to block wall.	AB	
1XJ	MCC 1XJ	Add padding or brace 1XI to block wall.	AB	
1XK	MCC 1XK	Add padding between brick wall and 1XK.	AB	
1XL,1XN	MCCs 1XL & 1XN	Replace missing anchors on 1XL & 1XN. Trim cable shoe. Add rigid support to tray in E-W direction. Add padding between 1XL & 1XUB and 1XN & 1XUB. Bolt 1XL & 1XN back to back	AB	
1XO	MCC 1XO	Bolt 2 North bays of 1XO together. Replace 3/8" anchor with external clip angle and anchor.	AB	
1XP	MCC 1XP	Add padding between 1XUA and 1XP.	AB	
1XR	MCC 1XR	Add top bracing or add washer plates to back row of anchors for 1XR.	AB	
1XS1	MCC 1XS1	Add padding between 1XS1 and HVAC on East side.	AB	
2A/MCB,2B/MCB,2A/3 B/SW	2A/2B MCB & SWITCHES	Add washers to bolts which bolt 2A/MCB & 2B/MCB panel to unistrut frame.	AB	
2ADB	ISOLATION DIODE ASSEMBLY	Repair unattached ground wire	AB	Completed
2AT3	Area Termination cabinet	Remove eye bolt lifting piece from NW corner of 2AT1.	AB	
2AT8	Area Termination cabinet	Trim cable tray adjacent to 2AT8.	AB	
2B/XFMR	600V XFMR 2B	Add weld between 2B/XFMR and plate.	AB	
2CR-FRAME	Cable Room PBB frame	Add brace to unistrut frame supporting PPBs in the cable room.	AB	
2CTK000C		Detailed analysis of column supports or structural enhancements required.	TB	
2DA	Keowee Dist. Center	Add anchorage to K-AHU0003.	Keowee	Completed
2DCA	Distribution Center A	Attach ground wire to bus bar.	AB	Completed
2EB1-2EB8	Electrical Boards	Perform in-situ modal testing	AB	
2EB8	Electrical Boards	Remove 1EB8 and add side panel to 1EB7.	AB	
2EHTC1,2EHTC2	Electric Hydraulic Terminal Cabinets	Add compressible material between 2EHTC1&2 and 2EHC1 to prevent impact.	AB	
2EPSLP1	Emergency Power Switching Logic Panel	Tighten loose mounting screw for relay 27NYB2	AB	Completed

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
2EPSLP2	Emergency Power Switching Logic Panels	Bolt 2EPSLP2 to adjacent SUPERVISORY PANEL and disable shock mounts on 2EPSLP2.	AB	
2ES/ICS/AUX	ESFAS,ICS & Aux. Cabinets	Add hard washers to anchors.	AB	
2ESFAS	Engineered Safeguards Cabinet	Add padding between ESFAS and adjacent column and file cabinet.	AB	
2ESTC2	Engineered Safeguards Cabinet	Conduit on North side of 2ESTC2 must be trimmed to clear cabinet.	AB	
2ESTC3	Engineered Safeguards Cabinet	Conduit coming out of top of 2ESTC3 must be modified to relieve impact concern with cable tray above cabinets.	AB	
2FDWVA0316	FDW Valve 316	Remove hand wheel chain from 2FDWVA0316 and revise procedures as needed to ensure chaining of hand wheel will not reoccur.	AB	
2ICS CABS	Integrated Systems Logic Cabinet	Add padding between ICS and adjacent column and file cabinet.	AB	
2KESP	Keowee Emergency Start Panel	Bolt to or add padding between RC Pump Motor Cabinet and 2KESP. If cabinets are bolted together, shock mounts on KESP must be disabled.	AB	
2MC-12	Instrument Rack	Add top bracing to instrument rack.	TB	
2MFBMRP	Main Feeder Bus Monitor Relay Panel	Remove conduit attaching to 2MFBMP.	AB	
2MTC2,2MTC4	Misc. Terminal Cabinets	Replace missing screws in relays	AB	Completed
2PIR	Pneumatic Instrument Rack	Revise mounting of 2RCIS0148 to provide a more rigid support.	AB	Resolved Analytically
2RCPT0166P	Reactor Coolant Pressure Switch	Interaction with adjacent pipe insulation is OK for A-46 but needs to be reviewed for IPEEE accelerations.	RB	
2RPS	Reactor Protection System	Add padding between RPS and adjacent column and file cabinet.	AB	
2TC	4160 Switchgear	Relocate ladder rack at column K30.	TB	
2TC,2TD,2TE	4160 Switchgear	Restrain or seismically qualify fluorescent bulbs in overhead fixtures.	TB	
2TD	4160 Switchgear	Relocate "I&E Battery Eq. Storage Cabinet".	TB	
2TSLS0001(2TSLS63SA)	Turbine Sump Level Switch	Relocate switch due to interaction	Keowee	Resolved Analytically
2UB,VB AB's	Unit, Vertical & Auxiliary Boards	Enhance existing anchorage to meet IPEEE.	AB	
2UB2	Unit board 2	Relocate drawing stick sets located behind 2UB2	AB	

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
2X01	Load Center 2X01	Weld transformer section of Load Centers 2X01 to embedded angle.	TB	
2X02	Load Center 2X02	Weld transformer section of Load Centers 2X02 to embedded angle.	TB	
2X10/XFMR	4160v to 600v XFMR 2x10	Add clip angles to to restrain transformers 2X10.	TB	
2XA		Develop analytical analysis of ~36" pipe on North side of 2XA. Restrain fire hose rack on North side of 2XA.	TB	
2XA-A	MCC 2XA-A	Enhance existing anchorage of 2XA-A.	TB	
2XC	MCC 2XC	Add back to back bolting to 2XC.	TB	
2XGB	MCC 2XGB	Add back to back bolting to the bottom north end of 2XGB. Enhance existing anchorage 2XGB. Add restraint or seismically qualify fluorescent bulbs on West side of 2XGB.	TB	
2XI	MCC 2XI	Add padding or brace 2XI to block wall(not required but good practice).	AB	
2XJ	MCC 2XJ	Add padding or brace 2XJ to block wall.	AB	
2XL,2XN	MCCs 2XL & 2XN	Bolt back to back or add top bracing to MCC's. Trim cable tray and restrain horizontally	AB	
2XO	MCC 2XO	Add washer plates, tighten loose bolts and add shims to 2XO.	AB	
2XP	MCC 2XP	Add shims between inverted channel and concrete at all anchors were gaps exist for 2XP.	AB	
2XSF (208V)	208v MCC 2XSF	Add padding between 2XSF(208v) and 3XSF(208v).	SSF	
2XSF (600V)	600v MCC 2XSF	Add padding between 2XSF(600v) and 3XSF(600v).	SSF	
3A/MCB,3B/MCB,3A/3B/SW	3A/3B MCB & Switches	Add washers to bolts which bolt 3B/MCB panel to unistrut frame.	AB	
3AB3	Auxiliary Boards	Modify the cabinet column penetration for 3AB3 to provide greater clearance.	AB	
3BSPU0002	RBS Pump B	Add washer to SW corner anchor.	AB	
3C,3D	Presurizer Heater Panels	Add bracing to column supporting Pressurizer Heater Cabinet platform.	RB	
3CA/BB	Battery Bank CA	Add anchorage to AHU 3-31(0VSAH0031).	TB	
3CA/BC	CA Battery Chargers	Add washer plate to NW anchor of 3CA/BC.	AB	
3CCD000A	Condenser Hotwell A	Perform calculation to verify adequacy of 4" line connecting to 3CCD000A.	TB	
3CR-FRAME	Cable Room PBB frame	Add brace to unistrut frame supporting PPBs in the cable room to meet FS = 1.88.	AB	
3CRDACBKRCAB	AC Breaker Cabinet	Remove unistrut on south side of breaker panel.	TB	
3CTK000C	Upper Surge Tank Dome Tank	Detailed analysis of column supports or structural enhancements required.	TB	

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
3EB1-3EB8	Electric Boards	The light fixtures opposite 3EB1-3EB8 need to have safety cables installed.	AB	
3EB1-3EB8	Electric Boards	Move or anchor file cabinets located opposite 3EB1-3EB8	AB	
3EHC1,2,3	Electric Hydraulic Control Cabinets	Repair loose anchors on north side of 3EHC1. Add compressible material between EHTC cabinets and EHC cabinets to prevent impact.	AB	
3EPSLP2	Emergency Power Switching Logic Panels	Revise drawings to reflect as-found anchor configuration. Cabinet is adequate but drawing revision is required.	AB	
3ES/ICS/AUX	ESFAS,ICS & Aux. Cabinets	Add hard washers to anchors.	AB	
3ESFAS	Engineered Safeguards Cabinet	Add padding between ESFAS cabinets and adjacent column and file cabinet. Relocate small table and trash can on North end, emerg. cart on wheels and OSC supply cabinet on South end.	AB	
3ESTC1	Engineered Safeguards Cabinet	Add plate washers to oversized holes for 3ESTC1.	AB	
3ICS CABS	Integrated Systems Logic Cabinet	Add padding between ICS cabinets and adjacent column and file cabinet.	AB	
3MTC3,4	Misc. Terminal Cabinet	Cut 1/4 inch off angle leg adjacent to 3MTC3 & 4 over the length of the angle.	AB	
3POWDEXPANEL	Powdex Panel	Remove misc. loose items from cabinet floor. Install clip restraints or seismically qualify fluorescent lights inside of cabinet and mounted to front hood.	TB	
3RCPS0364	Reactor Coolant pressure Switch	Add Vert. & Lateral support 1" Dia. pipe adjacent to 3RCPS0364.	RB	
3RPS	Reactor Protection System	Add padding between ICS cabinets and adjacent column and file cabinet.	AB	
3RSC-3FDW-368,369,372,374,382 & 384/ENCL	Motor Starter Panels	The unistrut needs to be cut at the blockwall/concrete wall interface and additional anchorage added as needed.	AB	
3SGLC	Steam Generator Logic Cabinet	Replace existing washer plates with thicker ones.	AB	
3TC,3TD,3TE	4160v Switchgear	Restrain or seismically qualify fluorescent bulbs in overhead fixtures.	TB	
3TCPA	Misc. Cabinet	Remove or restrain loudspeaker mounted above 3TCPA.	TB	
3UB,VB AB's	Unit,Vertical & Auxiliary Boards	Enhance existing anchorage to meet IPEEE.	AB	
3UB,VB,AB,EB & EF's	Control Room Unit,Vert. Aux. & Electric Boards	Enhance existing anchorage to meet IPEEE.	AB	

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
3VSAH0029	Altrex cabinet Cooling Coil	Add anchorage to 3VSAH0029.	TB	
3XA	MCC 3XA	Enhance existing anchorage of 3XA. Develop analytical analysis of ~36" pipe on North side of 3XA.	TB	
3XA-A	MCC 3XA-A	Replace missing bolt (back to back, bottom East) for 3XA-A. Enhance existing anchorage for 3XA-A.	TB	
3XGA/XFMR	XFMR 3XGA	Enhance existing anchorage for 3XGA/XFMR to meet A-46 & IPEEE.	TB	
3XGB	MCC 3XGB	Enhance existing anchorage of 3XGB. Trim 1" from Main Steam pipe insulation above 3XGB.	TB	
3XI	MCC 3XI	Add padding or brace 3XI to block wall.	AB	
3XJ	MCC 3XJ	Add padding or brace 3XI to block wall.	AB	
3XO	MCC 3XO	Add padding or move cable tray member to prohibit impact between conduit and cable tray adjacent to 3XO. Remove loose angle from top of MCC.	AB	
3XS1	MCC 3XS1	Repair latch to #4-D/E & Add washer plates.	AB	
3XT,3XT/XFMR	MCC & XFMR 3XT	Add bracing to block wall adjacent to 3XT and 3XT/XFMR.	AB	
BB-1,BB-2	Keowee Batteries	Change spacer material between batteries to non - compressible material	Keowee	Completed
CB01-10/EB01-10	Control Boards	Enhance ceiling supports in Keowee Control Room.	Keowee	Completed
CB01-10/EB01-10	Control Boards	Relocate work station adjacent to EB8 & 9.	Keowee	Completed
CB01-10/EB01-10	Control Boards	Remove chairs on rollers in Keowee Control room and replace.	Keowee	Completed
RB2,3,6,7,8,10,RF2,3,6	Westinghouse Switchboard	Remove or secure telephone	Relay House	Analytically Resolved
RB2,3,6,7,8,10,RF2,3,6	Westinghouse Switchboard	Relocate file cabinet and desk adjacent to RB2,3,6,7,8,10,RF2,3.	Relay House	In Progress
RB2,3,6,7,8,10,RF2,3,6	Westinghouse Switchboard	Restrain overhead fluorescent lights in 230kV Relay House.	Relay House	Analytically Resolved
RF17,RB17	External Grid Protection System	Add anchorage to unanchored cabinet (SY-DC2) adjacent to RF17,RB17.	Relay House	Completed
SRF6,7,8,9,10,17,SRB6,9,14,15,17	External Grid Protection System	Add anchorage to adjacent Distribution Center(SY-DC1). Replace missing bolt between SRF17 & SRB17.	Relay House	Completed
SY-DC1, SY-DC2	Switchyard Distribution Centers	Add weld to existing anchorage for SY-DC1, SY-DC2.	Relay House	Completed
SYTC1,2,3,4,5,8,12,15,17,18,19	Switchyard Terminal Cabinets	Brace SYTC cabinets to adjacent structural columns and bracing.	Relay House	Completed

TABLE 6-1

ENHANCEMENTS RESULTING FROM THE IPEEE PROGRAM

Equipment ID	Name	Enhancement Description	Bldg.	Comments
Units 1,2 & 3 A/B/SW,A/MCB,B/MCB,A/REG,B/REG,A/XFMR & B/XFMR,A/REG & B/REG .	Equipment Room Unistrut Frames	Add bracing to unistrut frames supporting Units 1,2 & 3 A/B/SW,A/MCB,B/MCB,A/REG,B/REG,A/XFMR & B/XFMR,A/REG & B/REG .	AB	
XOD1	MCC XOD1	Replace existing clip angles on XOD1 with angles meeting minimum edge distance. Replace anchors with corrosion resistant anchors. Provide protection for XOD1 from vehicle or equipment impact. Add padding between XOD1 exterior enclosure and XOD1 cabinet.	YD	
XOD2A	MCC XOD2A	Enhance existing anchorage to meet IPEEE.	YD	

Attachment 3

OCONEE NUCLEAR PLANT UNITS 1, 2, AND 3 INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS (IPEEE) TECHNICAL EVALUATION REPORT FOR HIGH WINDS, FLOODS, AND OTHER EXTERNAL EVENTS (HFO) ANALYSIS

TECHNICAL EVALUATION REPORT ON THE REVIEW OF OCONEE INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS (IPEEE) SUBMITTED ON HIGH WIND, FLOOD AND OTHER EXTERNAL EVENTS (HFO)

1.0 INTRODUCTION

Oconee consists of three similar units with each unit having a B&W pressurized water reactor (PWR) with a large dry containment. Oconee is owned and operated by Duke Power Company, and is located about 30 miles west of Greenville, South Caroline. Each unit is rated at 2568 MW(t). Unit 1 and Unit 2 received their construction permits (CPs) in 1967 and their operating licenses (OLs) in 1973, whereas Unit 3 received its CP in 1967 and its OL in 1974.

2.0 SCREENING OF EXTERNAL HAZARDS

The licensee used the progressive screening approach described in NUREG-1407 to screen external hazards and found that there were no other plant-unique external events that pose a significant threat of severe accidents within the context of the NUREG-1407 screening approach.

3.0 HIGH WINDS

The Oconee final safety analysis report (FSAR) gives the design basis wind velocity as 95 mph based on a 100 year mean recurrence interval. Since all class 1 structures at Oconee are designed for at least 95 mph, the probability of damage to important structures or components from non-tornadic (straight) wind at Oconee is low compared to that of tornadoes. In addition, the licensee evaluated the impact of hurricanes on Oconee. Since Oconee is located more than 220 miles from the nearest coastal area, the probability of severe wind damage at Oconee due to hurricanes is very unlikely.

The licensee provided an update to an earlier tornado study for Oconee (NSAC/60). The licensee estimated that the core damage frequency (CDF) initiated by tornadoes was about 1.3E-5/year. The licensee identified that the standby shutdown facility (SSF) has the highest impact on the tornado CDF. The licensee recommended that station personnel study enhancements to the natural disaster procedure to provide guidance to ensure that prompt activation of the SSF is achieved following a tornado event. The licensee noted that this review should also consider the adequacy of sheltering plans of all plant personnel needed during the post-event recovery stage following a tornado event which might cause some structural damage to the plant.

4.0 EXTERNAL FLOODS

Since the licensee's original IPEEE submittal did not provide sufficient information on Generic Issue (GI)-103, "Design for Probable Maximum Precipitation (PMP)," the staff sent the licensee a request for additional information (RAI). In response, the licensee referred to an updated flood study which includes the Keowee dam and reservoir. The updated flood study used the criteria in the hydrometerological reports which were listed in Generic Letter 89-22. The PMP for Oconee was estimated to be 26.6 inches within 48 hours. The results of the updated flood study showed that the Keowee reservoir could accommodate the reservoir flooding resulting

from a PMP. The licensee has also assessed the effects of greater roof ponding levels due to a PMP.

The licensee estimated that the CDF due to external flooding initiated by a random failure of the Jocassee Dam is about 7E-6/yr. The licensee noted that the external flooding CDF is dominated by failures of SSF when floods exceed the 5-foot SSF flood barrier.

5.0 TRANSPORTATION AND NEARBY FACILITY ACCIDENTS

The licensee evaluated aircraft impact accidents, road and rail accidents, and fixed facility accidents, including industrial facilities, military facilities, and pipeline accidents.

Regarding the aircraft impact accidents, the licensee noted that there were four airways in the vicinity of the plant site. The licensee estimated the probability of an aircraft crashing into the site was about 1.1E-8/year. Therefore, the licensee concluded that aircraft accidents could be screened out.

The effects of a marine transportation accident on the plant CDF also seem to be minimal because there is not much commercial marine transportation activity near the plant.

Regarding rail accidents, the licensee noted that the closest rail lines come within about 6 miles of the plant site and would not significantly affect the operation at Oconee.

With respect to highway trucking accidents, the licensee noted that two state highways pass within 1 mile of the plant site. The licensee determined that a toxic gas release from a highway accident would have a minimal effect on the control room. In addition, the licensee examined the effects of an explosion from a highway accident and determined that [redacted] (b)(7)(F)

The licensee evaluated accidents from nearby facilities and determined that there were no manufacturing or military facilities within five miles of the site. Although hazardous chemicals are shipped to and from several industrial facilities located between 7 and 10 miles from the plant site, the licensee determined that none of them would affect the operation at Oconee.

Regarding a release of toxic chemicals in the event of onsite hazardous material accidents, the licensee noted that chlorine and hydrazine were stored onsite. Because there are chlorine detectors onsite, and the control room is a self-contained, controlled environement furnished with self-contained breathing equipment, the effects of a toxic gas release onsite would have a minimal effect on the control room.

Regarding an explosion accident from a release of flammable material stored onsite, the licensee noted that propane and hydrogen are stored onsite. The propane tanks were found to be capable of withstanding a design basis earthquake without sliding or overturning. To prevent inadvertent contact with heavy equipment or other vehicles, robust barriers have been installed around each propane tank. Therefore, the licensee concluded that an explosion from

a propane tank accident is unlikely. With respect to a hydrogen explosion accident, the licensee noted that all areas, with the exception of letdown storage tank (LDST) rooms, have adequate ventilation to maintain hydrogen concentration below 0.1%. The licensee made two recommendations to modify the ventilation system exhaust in each LDST room and to provide guidance to operators to prevent hydrogen buildup. The first recommendation has been implemented. The LDST rooms were screened out during the fire/seismic review because an explosion or fire in these rooms would have little impact on safety-related systems.

Regarding gas pipeline rupture accidents, the licensee noted that natural gas lines are located about 3.5 miles from the plant site. The gas lines have an operating pressure of about 400 psi. The licensee concluded that a rupture of these lines would not affect the operation at Oconee. In addition, the licensee noted that there are two off-site propane storage facilities near the plant site. Because of the distances between these facilities and the plant site, the licensee concluded that an explosion at either of these propane storage facilities would not affect the operation at Oconee.

6.0 OTHER PLANT-UNIQUE EXTERNAL EVENTS

The licensee provided specific discussions on 20 other external events (e.g., avalanche; costal erosion; drought, high summer temperatures, low lake or river water level; fog; forest fire; frost, hail, snow, ice cover; hurricane; landslide; lightning; meteorite; intense precipitation; river diversion; sandstorm; seiche; soil shrink-well consolidation; storm surge; tunami; turbine-generated missiles; volcanic activity; and waves). The licensee concluded that there were no plant-unique external hazards at Oconee.

7.0 GENERIC SAFETY ISSUES (GSIs)

(1) GSI-103, "Design for Probable Maximum Precipitation"

The licensee has assessed the effects of flooding and roof ponding as a result of Probable Maximum Precipitation (PMP) (information provided in the licensee's RAI responses dated March 31, 1999, and October 4, 1999). The staff finds that the licensee's GSI-103 evaluation is consistent with the guidance provided in Section 6.2.2.3 of NUREG-1407, and therefore the staff considers this issue resolved.

(2) GSI-156, "Systematic Evaluation Program (SEP)"

The licensee's IPEEE submittal and other associated documentation were reviewed for information directly addressing the following HFO-related SEP issues: dam integrity and site flooding (Section 5.2 of IPEEE); site hydrology and ability to withstand floods (Section 5.2 of IPEEE); industrial hazards (Section 5.3 of the IPEEE); tornado missiles (Section 5.1.2 of IPEEE); severe weather effects on structures (Section 5 of IPEEE); and design codes, criteria, and load combinations (Section 3.1 of IPEEE). Based on the results of the IPEEE submittal review, the staff considers that the licensee's process is capable of identifying potential vulnerabilities associated with these issues. On the basis that no potential vulnerability associated with these issues was identified

in the IPEEE submittal, the staff considered the HFO-related aspects of these issues resolved.

(3) GSI-172, "Multiple System Responses Program (MSRP)"

The licensee's IPEEE submittal contains information directly addressing the following HFO-related MSRP issue: effects of flooding and/or moisture intrusion on non-safety related and safety-related equipment (Section 3.1.2.3 of IPEEE). Based on the overall results of the staff's IPEEE submittal review, the staff considers that the licensee's process is capable of identifying potential vulnerabilities associated with this issue. On the basis that no potential vulnerability associated with this issue was identified in the IPEEE submittal, the staff considers the HFO-related aspects of this issue resolved.

8.0 CONCLUSIONS

The IPEEE submittal is judged to meet the intent of Supplement 4 to Generic Letter 88-20, for the high winds, floods, transportation and other external events. The licensee found no vulnerabilities with respect to HFO events.

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS

TECHNICAL EVALUATION REPORT

FOR FIRE ANALYSIS

Enclosure 3

Review of the Submittal in Response to U.S. NRC Generic Letter 88-20, Supplement 4: "Individual Plant Examination-External Events"

Fire Submittal Screening Review Technical Evaluation Report: Oconee Revision 5: October 13, 1999

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1.0 INTRODUCTION

This Technical Evaluation Report (TER) presents the results of the Step 0 review of the fire assessment reported in the "Oconee Nuclear Station, IPEEE Submittal Report" [1], requests for additional information (RAI) based on questions raised during the initial review [2], and the licensee responses to those questions [3].

1.1 Plant Description

The Oconee Nuclear Station consists of three units - Unit 1, Unit 2, and Unit 3. Commercial operation began in 7/73, 9/74, and 12/74 for Units 1, 2, and 3, respectively. Each produces 2568 MW, from a two loop B&W PWR nuclear steam supply system (NSSS) and turbine generator supplied by General Electric Company. Each unit has a steel lined, concrete Reactor Building. All three units share the Turbine Building. It appears that there is also only one Control Room for all three units. The site has two Auxiliary Buildings; one of which serves Units 1 and 2. The Component/Service Cooling Water Systems supply water to safety-related equipment. The ultimate heat sink for the station is Lake Keowee, an impoundment on the Keowee River.

Engineered safety features for each unit include an Emergency Core Cooling System (ECCS), core flooding tanks, Reactor Building Spray System and Emergency Coolers, Emergency Feedwater (EFW) System, Penetration Room Ventilation System, and Reactor Building Isolation System. The ECCS consists of two subsystems; the High Pressure Injection (HPI) System and the Low Pressure Injection (LPI) System. The HPI system is also the charging system and contains three motor-driven pumps. The LPI system consists of three motor-driven pumps that also perform the residual heat removal function and provide suction to the HPI pumps for recirculation. The EFW system consists of two motor driven pumps and one turbine driven pump. The latter can be cross-tied between units. The two units of the Keowee hydroelectric station, which is located at the nearby Keowee Dam provide emergency power. Backup power is also available through a dedicated line from three combustion turbine units at the Lee Steam Station, approximately 30 miles away.

The Standby Shutdown Facility (SSF) contains the only diesel generator (DG) at the plant. The SSF is a dedicated safe shutdown system, separate from the other safety-related plant systems, which serves all three units. It is designed to meet Appendix R requirements. To protect it from fires and other hazards, it is physically located in the yard, away from and independent of the main control room. The SSF DG is an independent power source for the SSF safe shutdown systems. These include the auxiliary service water (ASW) system which provides water to the steam generators, and the reactor coolant makeup (RCM) system which also provides seal injection to the RCP seals.

1.2 Review Objectives

The performance of an IPEEE was requested of all commercial U.S. nuclear power plants by the U.S. Nuclear Regulatory Commission (USNRC) in Supplement 4 of Generic Letter 88-20 [4]. Additional guidance on the intent and scope of the IPEEE process was provided in NUREG-1407 [5]. The objective of this Step 0 screening review is to help the USNRC determine if the Oconee submittal

has met the intent of the generic letter and to also determine the extent to which the fire assessment addresses certain other specific issues and ongoing programs.

1.3 Scope and Limitations

The Step 0 review was limited to the material presented in the Oconee IPEEE submittal and responses to requests for additional information (RAI). RAIs were submitted to the licensee based on an initial review of the submittal alone. Furthermore, the review was limited to verifying that the critical elements of an acceptable fire analysis have been presented. An in-depth evaluation of the various inputs, assumptions, and calculations was not performed. The review was performed according to the guidance presented in Reference 6. The results of comparing the review against the guidance in this document are presented in Section 2.0. Conclusions and recommendations as to the adequacy of the Oconee IPEEE submittal with regard to the fire assessment and its use in supporting the resolution of other issues are presented in Section 3.0.

2.0 FIRE ASSESSMENT EVALUATION

The following subsections provide the results of the review of the Oconee fire assessment. The review compares the fire assessment against the requirements for performing the IPEEE and its use in addressing other issues. Both areas of weakness and strengths of the fire assessment are highlighted.

2.1 Compliance with USNRC IPEEE Guidelines

The USNRC guidelines for performance of the IPEEE fire analysis derive from two major documents. The first is NUREG-1407 [5], and the second is Supplement 4 to USNRC Generic Letter 88-20 [4]. In the current screening assessments, the adequacy of the utility treatment in comparison to these guidelines has been made as outlined in "Guidance for the Performance of Screening Review of Submittals in Response to U. S. NRC Generic Letter 88-20, Supplement 4: 'Individual Plant Examinations - External Events,'" Draft Revision 3, March 21, 1997 [6]. The following sections discuss the utility document in the context of the specific review objectives set forth in this Screening Review Guidance Document and assess the extent to which the utility submittal has achieved the stated objectives.

2.1.1 Methodology and Documentation

The fire probabilistic risk assessment (PRA) evaluation in Revision 1 of the Oconee PRA, which is an update of the EPRI NSAC-60 Oconee PRA, was the basis for the quantitative fire analysis of the IPEEE. The licensee says an additional evaluation was done to verify assumptions, technical inputs, and conclusions of this portion of the Oconee PRA. This resulted in Revision 2 to the fire analysis and was included as Appendix B in the submittal. Only the Turbine Building and Cable Shaft fire zones were analyzed in detail and the cable shaft was not analyzed using PRA methods. A plant walkdown was conducted to evaluate the Fire Risk Scoping Study (FRSS) issues [14].

The study documented in the Revision 1 Oconee PRA focused on Unit 3 alone. The licensee indicates that walkdowns and supporting evaluations were conducted for all three units as part of this PRA. For the Oconee IPE, an analysis was done by the licensee to determine the applicability of the Unit 3 PRA results to Units 1 and 2. The conclusion by the licensee was that the differences between the units do not measurably change the CDFs or risk between the Oconee units. The IPEEE submittal implies that this result applies to the external events, e.g., fire, considered because they were analyzed in the Oconee PRA for Unit 3. However, the applicability of this assumption depends on the validity of the IPEEE fire analyses. A more detailed analysis might have shown that differences between the units produce fire assessment results that are unique to a given unit.

The IPEEE fire submittal cites supporting second tier documentation as the source for some of the inputs and results. Many of these supporting documents and the analyses contained in them have not been examined in this review of the IPEEE submittal. However, due to their importance to the analysis conclusions, portions of the Oconee PRA, including Appendix B in the submittal, and the method used to analyze fires in the cable shaft and some Auxiliary Building areas were reviewed.

The Oconee fire analysis began with the identification of "critical zones," a subset of plant zones and compartments assessed for importance in the fire study. Within the critical zones, many sub-zones were qualitatively screened based on the conclusion that the fire risk was bounded by that of a fire in one of two areas analyzed quantitatively: the Cable Shaft (CS), and the Turbine Building (TB). Thus, the Oconee approach *qualitatively* screened all plant areas against the only two areas that eventually were assessed *quantitatively*. The set of zones and compartments of the plant considered in this assessment was not provided. Nor were the criteria used to identify the "critical zones" discussed.

In the sense of a PRA, the Turbine Building and Cable Shaft are the dominant fire risk contributors according to this study. However, since no other areas were modeled, the total fire risk was not determined.

The review of the original Oconee submittal identified a number of recurring concerns among the technical reviewers (technical reviewer concerns, or TRCs). These are referenced in subsequent sections of this report, and include the following:

TRC1. Qualitative Screening, Screening Basis: Only the cable shaft and the Turbine Building were not screened qualitatively. Several fire zones (e.g., equipment rooms and the main control room (MCR)) were qualitatively screened without specifying the basis for screening beyond the argument addressed in TRC2. This was considered to be a key issue and led to RAI #2.

TRC2. Bounding Scenarios: Several key areas were considered and dismissed, i.e., "screened," based on the assessment that their contributions to fire risk were less than the contributions from either the Turbine Building and Cable Shaft fires. (In the submittal, the term "risk" appears to connote "consequence.") Fire risk contributions from areas dismissed in this manner were not modeled or quantified. The language used in the submittal referred to fires in various plant areas as being "bounded" by one of these fires. RAIs #3 and #4 addressed this issue.

TRC3. Quantification Technique: Only the Turbine Building and Cable Shaft fires were quantified and only large fires were considered. Previous PRA results and EPRI fire events data were used in quantifying the Turbine Building fire, which is a typical approach taken in many IPEEE fire studies. However, the simplified method of quantification used in the Cable Shaft fire analysis [7] weakened the conclusions that followed from the Cable Shaft results. Use of this technique significantly influenced the fire risk conclusions and resulted in RAI #1.

The method described in Reference 7 is referred to as a "Simplified Critical-Path Analysis" method. It consists of determining the probability of the following successive events:

- Event D - *probability of incipient fire based on probabilities of combustion being discovered, (suppressed or not suppressed).*
- Event H - *probability of meaningful (developing) fire based on Event D plus probabilities*

of fire being discovered, automatically detected, and manually suppressed; fuel availability; and failure of automatic suppression.

- Event M - *probability of total room involvement based on Event H plus probabilities of fire being discovered, automatically detected, and manually suppressed; fuel ?continuity?; availability of oxygen; and failure of automatic suppression.*
- Events Q and U - *probability of fire communicating to adjoining space based on Events M or H plus probabilities of fire being discovered, automatically detected. and manually suppressed; availability of oxygen; and failure of elements that enclose fire area.*

In the Oconee analysis the last two events were ignored. For the other events the probabilities were selected from the judgmental values provided in Reference 7 rather than being based on plant specific or generic, e.g., FIVE [12], values. Conservative values were selected for some of the event parameters, such as automatic suppression failure (1.0). Automatic detection was estimated to occur with a minimum success probability of 0.9 and manual suppression was estimated to be successful 90% of the time with a response time of three minutes. Also, as can be seen from the above event descriptions, it appears that the method can lead to redundant credit for suppression and detection.

TRC4. Fire Propagation: The failure of fire barriers was not included in the detailed analyses. As noted in TRC3, Events Q and U were ignored in the Cable Shaft evaluation. Other potentially important scenarios resulting from fire spread from one area to another were not discussed. (The response to RAI #5 indicated that this concern was addressed during walkdowns.)

TRC5. Model Parameter Selection/Analysis Documentation: Some data, geometry, and other assumptions used in the detailed calculations were included in the submittal. However, for key portions of the analysis, information concerning the bases for selecting particular model parameters used was not provided. For example, the bases for the values selected for the cable shaft fire model were not discussed. Documentation was not sufficient that a detailed evaluation of the fire analysis results could be performed.

Other weaknesses of the submittal included the following:

- Core damage sequence results were calculated for the Turbine Building fire using the Oconee PRA model; however, no event and fault trees were provided. Only summary analysis results and fire sequences were provided. Therefore, the events associated with the various sequences were not examined during the review.

- The consideration of only large fires ignored the potential risk associated with smaller, higher frequency fires. This concern led to RAI #6.

- The treatment of Appendix R and non-Appendix R safety related equipment and cables was not specifically described in the submittal.

The methodology used in the submittal is regarded as weak compared to more current methods of PRA and fire modeling. The tools used could have been applied to additional fire areas. Additional

methods could have been employed to improve several portions of the fire assessment, e.g., fire and damage modeling, human error analysis.

As a result of the above findings, and others discussed subsequently in this report, requests for additional information (RAIs), some already noted, were submitted to the licensee. Responses to these RAIs addressed some of the concerns, but the analysis still contains weaknesses that are discussed in this report.

2.1.2 Plant Walkdown

The walkdown team consisted of a fire protection engineer from the Duke Power General Office, a PRA analyst from the Duke Power General Office, a fire protection engineer from Oconee, consultants from Duke Engineering and Services, and the program manager for the project.

Several sources of information were used to provide input to the plant walkdowns that were conducted. Oconee plant documents utilized included Pre-Fire Plans, General Arrangement Drawings, Fire Protection Drawings, PRA and associated walkdowns, and the Oconee Nuclear Station Appendix R Notebook.

According to the submittal, if PRA assumptions and inputs were found to be incompatible with station specific arrangements and configurations, or conclusions could not be verified, the fire PRA was revised accordingly. The only specific items mentioned in this regard included:

- The licensee identified a need to better document the review of the Auxiliary Building zones.
- The results of the walkdown and subsequent analysis resulted in Revision 2 to Section 3.5 of the Oconee PRA document. This section was included in the submittal as Appendix B.

Expected results of the walkdowns, such as identification of ignition sources and targets, and location of safe shutdown cables were not discussed in the original submittal (ref TRC5). However, information from walkdowns was used as input to the responses to some of the FRSS issues. The response to RAI #6 discussed the detailed walkdowns that were conducted of areas in which a fire could affect safe plant shutdown. The response to RAI #5 noted that the potential for fire, heat, smoke, and suppressants to affect multiple units or important equipment in adjacent zones was considered in the fire walkdowns. Fire detection and suppression systems were also reviewed during a walkdown. Finally, walkdowns were used to support the evaluation of the containment response to fires.

2.1.3 Fire Area Screening

The first step of the Oconee fire analysis consisted of identification of critical zones. A list of the zones/compartments in the plant considered in this process was not provided. As discussed in Section 3.5 of Revision 2 of the Oconee PRA, five zones were identified. The Turbine Building was analyzed in detail. In the Auxiliary Building, all of the subzones except the cable shaft, which was

analyzed quantitatively using a simplified method, were screened as discussed under TRC1 in Section 2.1.1 of this report. As discussed below, the blockhouses and Reactor Building were screened using similar or bounding arguments (ref TRC2).

The remaining zone, the 230 kV Switchyard Relay House, was identified as an area where a fire could cause a LOSP, including LOSP from the Keowee hydroelectric station. This fire scenario was considered by the licensee to be included in the PRA analysis of LOSP events. As part of the IPEEE fire review, it was verified that the Oconee Unit 3 PRA included a transient initiator for a combined LOSP and loss of power from the Keowee overhead line.

The blockhouses are two zones adjacent to the Turbine Building. They contain 4 kV switchgear and a transformer (CT-4) which supplies emergency power to Oconee through an underground path from Keowee. According to the submittal, a large fire in the Unit 1 and 2 blockhouse could disable normal and emergency power for Units 1 and 2. However, due to the lack of liquid and transient combustibles in this blockhouse, this scenario was judged by the licensee to be less likely than the Turbine Building fire that was analyzed in detail. Also, the Turbine Building fire is considered to be more serious because it assumes the loss of EFW as well as ac power. The turbine-driven EFW pump would be available in the event of a blockhouse fire. However, the assumption that the Turbine Building fire would be more serious neglects the fact that the blockhouse fire frequency could be greater than the low value used for the Turbine Building fire. As a result, RAI #4 was submitted to the licensee asking that a risk evaluation be performed for the Units 1 and 2 blockhouse fires using data and assumptions (fire frequency, detection, suppression, recovery, etc.) specific to that particular plant area.

The licensee response cited the same arguments contained in the previous paragraph as justification for concluding that a Unit 1 and 2 blockhouse fire event is bounded (ref TRC2) by the Turbine Building fire. However, the results of a blockhouse fire frequency evaluation were also provided. The estimated value, computed using the simplified critical path method of Reference 7 and fire initiating data from AEOD Report S97-03 [8], is 4.3E-06/yr. This frequency is about one-quarter of the estimated Turbine Building fire frequency, but no detailed calculations or source data that resulted in this value were provided.

The response to RAI #4 did provide a qualitative discussion of the important assumptions and considerations used to compute the frequency and assess probable effects of a fire. Key factors mentioned included separation of the electrical power system into two divisions on opposite sides of the room; the need for a small fire to grow to "a space-consuming fire" to cause a plant transient; limited combustible material which would cause a fire in the blockhouse to spread; metal jacketed, ceramic insulated high voltage power lines in the blockhouse; metal enclosures surrounding each division breaker; and fire detectors in the blockhouses, along with portable fire extinguishers. The licensee concludes that a severe blockhouse fire would be nearly identical to a Turbine Building fire event from a PRA functional sequence perspective except that secondary-side heat removal would remain available. The reliability of the SSF would be the same for both events.

Based on the blockhouse fire frequency being one-fourth as large as the Turbine Building (TB) fire frequency, the licensee contends the blockhouse CDF will also be about one-fourth the estimated CDF due to the TB fire. Only limited quantitative information was provided in the response. However, in the licensee's estimation, the blockhouse will not provide an additional significant contribution to the total plant CDF. (A PRA approach would have evaluated the contribution of the blockhouse to the overall plant fire CDF.) The licensee's conclusion that the blockhouse is not a significant risk contributor is understood in the context of the methods used in the Oconee analysis, and the response to RAI #4 is acceptable.

In the case of the Unit 3 blockhouse, the emergency power path passes through a line from the Unit 1 and 2 blockhouse. The fire scenario for the Unit 3 blockhouse is similar to the fire scenario for the Unit 1 and 2 blockhouse, so it is also considered to be bounded by the Turbine Building fire scenario (ref TRC2). No qualitative criteria, e.g., the FIVE methodology, or quantitative information is presented to support either of these conclusions. As part of the RAI response discussed above, it was noted that a Unit 1 and 2 Blockhouse fire would cause Unit 3 to lose its Keowee underground emergency power source. However, two other power sources would still be available unless the fire grew enough to damage the other main feeder bus.

According to the submittal, a fire in the Reactor Building could lead to a plant trip due to a trip of the reactor coolant pumps. The possibility of a LOCA due to a fire in containment was dismissed based on the following:

- A pressurizer PORV opening due to a hot short could be closed from outside the Reactor Building by removing power. How this would be done or the probability of success were not specified.

- An interfacing LOCA due to the spurious opening of valves LP-1 and LP-2 as the result of a fire in the Reactor Building was dismissed by the licensee based on a previous analysis which was referenced. The results were not discussed in detail in the submittal.

As a result, the consequences of a fire in the Reactor Building were judged to be similar to those of a random reactor trip and bounded by the T1 initiating event portion of the PRA. This conclusion is reasonable, but the analysis was not discussed in the submittal. (ref TRC5)

The reactor coolant pump motors in the Reactor Building were identified as high energy electrical equipment that are not seismically mounted. Fires in these motors were judged not to be a concern based on the following:

- Important equipment cables are located away from the pumps or below them. This implies that fires will not spread to lower levels, i.e., propagation is not a concern.

- Structural steel around the top of reactor coolant pumps would deter the spread of small fires.

- A motor fire would be oxygen starved because the motor is sealed.

A number of levels in the Unit 3 Auxiliary Building, including the Control Rooms, were screened on the basis that no scram mechanisms were identified or no safe shutdown components (SSCs) are present. The latter criteria is acceptable if there is no potential for fire propagation (e.g., barriers present) to another level where SSCs are present that could be damaged. (ref TRC4) However, the lack of automatic scram mechanisms can not rule out the possibility of spurious signals that result in a manual scram.

Level 809 in the Auxiliary Building is of particular concern because it contains SSF cabling. The basis for screening fires that might damage these cables and/or affect the transfer of control to the SSF was not provided (ref TRC1). The effects that the layout and accessibility of this area might have on responding to a fire also were not discussed. Likewise, the importance of the Control Room in responding to fires makes it potentially risk significant and dictates that these areas be analyzed in some detail. RAI #3 addresses control room concerns and is discussed elsewhere in this report.

The table below shows what levels were considered, the possible effects of a fire, and why the level was screened.

Aux. Bldg. Level	Key Equipment	Fire Effect(s)	Screening Rationale
758	HPI & LPI Pumps	Normal plant shutdown due to pump fire	Initiating event due to fire unlikely (no scram)
771	(1) HPI suction isolation valves, ASW pump (not SSF ASW pump) (2) Let down storage tanks (H_2 source)	(1) Normal plant shutdown due to loss of HPI & LPI pump power supplies (2) Screened as fire initiator	(1)Initiating event due to fire unlikely (no scram) (2) Lack of important (SSC) equipt. in zone, shield walls around tanks
783	Comp. cooling pumps & coolers, spent fuel cooling pumps.	Not examined	Initiating event due to fire would not occur (no scram)
796	Equipment rooms (power supplies and control cables)	Plant transients due to misalignment or failure of key equipt., normal plant shutdown	Cable shaft fire *bounds* equipt. room fire risk, presence of CO_2 extinguishers & manual sprinkler systems.

Aux. Bldg. Level	Key Equipment	Fire Effect(s)	Screening Rationale
809	Rooms that contain electrical penetrations to: (1) Vital I & C battery rooms and (2) Reactor Building. (3) SSF cabling also present (4) Other penetration room equipment/cables	(1) Normal plant shutdown (2) Interfacing systems LOCA due to opening of valves LP-1 & LP-2 (3) Not discussed(TRC5) (4) No significant effects	(1) Initiating event due to fire unlikely (no scram) (2) Opening of valves due to fire not possible (3) Not provided (TRC5) (4) East & west rooms separated by three hour barrier, fires *bounded by* cable shaft fire.(TRC2)
822 & 825	Control Rooms	Not discussed	Constantly occupied, smoke detectors present, cable shaft fire risk *bounding*.
838, 844, & 844+6	Control Rm HVAC equipt., reactor bldg purge equipt.	Loss of CR ventilation, requiring evacuation	Even large fire that would disable redundant equipt. *bounded by* cable shaft fire risk

The fire area screening presented in the original submittal was qualitative and the plant was separated into large zones. The possibility of manual scrams was dismissed and the possibility of fire spread between areas was not discussed (ref TRC4). In addition, typically important areas were qualitatively screened based on being bounded (ref TRC2) by the cable shaft fire that (1) was analyzed using the simplified method (ref TRC3), and (2) would, in most cases, not bound the frequency of potential fires in the areas which were screened. As a result, it is concluded that typically important areas that could have been analyzed in more detail were screened (ref TRC1). These issues led to three RAIs being submitted to the licensee. These RAIs and the responses provide by the licensee are discussed in the following paragraphs.

The Auxiliary Building was one of the key areas in which fire risk was assumed to be bounded (ref TRC2) by the cable shaft fire risk. Several sub-zones (levels) in this building were qualitatively screened (ref TRC1) based on the assumption that the fire frequencies were bounded by the cable shaft fire. Since the Auxiliary Building includes a number of typically important fire zones, including some containing SSF cabling that could be significant risk contributors, RAI #2 was submitted to the licensee requesting that the fire areas in the Auxiliary Building be reexamined. The analysis was to include initial screening based on fire sources, potential fire damage, and mitigating features in each area. Detailed assessments were requested for areas that survive the initial screening process and could significantly impact the plant operation or systems.

The response to RAI #2 started with a discussion of the functions and capabilities of the SSF. This system is physically and electrically removed from the Auxiliary Building except for the

West Penetration room. As a result, the licensee says the SSF can be credited with mitigating the fire risk in all areas of the building except for the West Penetration room. According to the response, all 77 fire zones in the Auxiliary Building were walked down using detailed checklists to verify the PRA assumptions for each zone and to address the Fire Risk Scoping Study issues. If a fire in a zone would not result in an accident sequence initiating event it was screened. This resulted in 45 zones being screened out. For the remaining 32 zones, each zone and those adjacent to it were reviewed to determine if a fire could cause, in addition to an initiating event, damage to equipment necessary to mitigate potential accident sequences. It was stated that this information was used to perform the fire analysis.

The remainder of the response is devoted to a discussion of the potential effects of fire in zones associated with six different elevations in the Auxiliary Building. Using the information in Attachment 2 of the RAI response, it was possible to relate the elevations to the Auxiliary Building zones considered in the fire analysis, including the results of screening.

Elevation 758 houses the HPI pumps, LPI pumps, and the Reactor Building spray pumps. No fires that could initiate a plant transient were identified in the fire zones on this level. Elevation 783 houses the Component Cooling pumps and the level of the cable shaft just below the equipment room. Due to the similarity of consequences of a fire in this area to the cable shaft fire and fewer fire sources than in the equipment room, the CDFs for zones at this elevation were judged to be relatively small and no specific analyses for unique fire scenarios was performed. (Some zones in this area were analyzed with potential fires at elevation 838.) Elevation 822 contains the MCR which is the only zone at this elevation where a fire could cause an initiating event. The MCR was addressed in the response to RAI #3. Elevation 838 contains HVAC and radiation monitoring equipment. Fires in zones at this elevation could cause a plant trip; however, safe shutdown mitigating equipment will not, according to the response, be impacted.

Elevation 771 contains several zones where fires that could initiate a plant transient are postulated. The cable shaft, the analysis of which is discussed in the response to RAI #1, begins at this elevation. The critical fire zone at elevation 771 is assessed to be the LPI Hatch area. It contains two motor control centers that could be the source of an electrical cabinet fire. Such fires could cause the failure of the HPI and Component Cooling (CC) pumps, leading to a RCP seal LOCA. The events associated with the analysis of this scenario are discussed in detail in the response. The analysis concludes that the CDF for the scenario is 8.7E-09. However, some of the probabilities used for the events in the scenario were not well supported (ref TRC5). For example, the probability that the fire develops to a large fire that would affect multiple compartments in the cabinet is estimated using the same method [7] used to analyze the cable shaft fire. The resulting "propagation probability" is given as 8.2E-02 with no further justification (ref TRC5). Given the low fire ignition frequency for the MCC fire (9.7E-04), a low CDF for the scenario is nearly assured. Also, the effects of self-ignited cable fires at this elevation are discounted.

The last elevation discussed in the response to RAI #2 is Elevation 838. The key rooms at this

elevation are the East and West Penetration Rooms and the Cable Room (Cable Shaft). The cable shaft fire is discussed in the response to RAI #1 and the East Penetration Room is considered to be less significant than a fire in the West Penetration Room due to the availability of the SSF. As a result, only the effects of a potential fire in the West Penetration Room are discussed in detail. Such a fire is considered significant because it could damage normal hot shutdown equipment as well as the SSF. A seal LOCA can occur if seal cooling is lost from both of the normal seal cooling systems, CC and HPI, and backup seal cooling from the SSF reactor coolant makeup (RCM) system is not available.

As in the case of the significant fire at Elevation 771, the probability that the fire occurs in a critical location and propagates to a large fire that fails both CC and SSF RCM is estimated using Reference 7. The response says the availability of fuel and the probabilities of detection and suppression were factored into the assessment. Fire brigade response within ten minutes of the alarm was assumed. The end result was a "propagation probability" of 9.1E-02 (ref TRC5). The resulting CDF is 9.0E-10 so other West Penetration Room accident sequences were considered to have negligible impact. The magnitude of the CDF was significantly influenced by the requirement that HPI seal cooling fail randomly since it can not be affected by the West Penetration Room fire. This value (6.3E-05) combined with the probability of a fire occurring ensures a low CDF for the fire.

Overall the extensive response to RAI #2 supported the conclusion that the Auxiliary Building zones not discussed in the IPEEE submittal do not pose a significant fire risk. However, the use of the method (ref TRC3) to analyze one area and the lack of analysis detail provided for some zones (ref TRC5) reduced the credibility of the conclusions presented and represent weaknesses in an otherwise acceptable response to RAI #2.

As noted in the previous table, the MCR was screened by the licensee based on constant occupation, the presence of operators, and the fire risk being bounded by the cable shaft fire risk (ref TRC2). Since this was not consistent with typical fire risk assessment findings and the IPEEE requirements, especially those related to control system vulnerabilities, RAI #3 was submitted to the licensee. It requested a detailed fire analysis of the plant MCRs, including consideration of fire frequencies, the effects of control panel fires, damage to plant systems, the potential for MCR abandonment, and the timing of events related to abandonment and recovery from the SSF. The response was to include a description of the functions provided in the SSF and the capability to isolate these functions from damage in the MCR. The location of the MCR/SSF transfer switches, procedures for effecting the transfer, and an evaluation of the reliability of operator recovery using the SSF were also to be provided in the response.

The response to RAI #3 repeated some of the same arguments (continuously staffed MCR, etc.) in the submittal leading to the conclusion that the cable shaft fire is more risk critical. Additional arguments, e.g., more cable separation in the MCR than in the cable shaft, to support this conclusion were also provided. The response also states that the frequency of damaging MCR fires is low. A value of 0.003/yr is cited based on Reference 8. This is only one-third the value

recommended in FIVE [12]. The licensee contends that distributing the MCR frequency cited among the cabinets associated with core cooling and taking into account probable early suppression indicates that the frequency of a significant fire in the MCR should be substantially lower than in the cable shaft area.

Based on the response to RAI #1, the potential for hot shorts to interfere or preclude the use of the auxiliary shutdown panel (ASP) and the SSF is sufficiently small that, according to the licensee, it is not a concern, with the possible exception of the loss of seal cooling for the RCPs. The response to RAI #3 also states that core cooling can be maintained following a transient induced by an MCR fire either by using the ASP or implementing the SSF. The equipment controlled by the SSF is completely independent of the normal controls in the MCR or at the ASP. Also, no switching of control to the SSF is required.

The independent capabilities of the SSF, such as RCP seal cooling and supplying feedwater to the steam generators, were described in the response to RAI #3. The independence of the SSF electric power and instrumentation were also described. The final conclusions provided in the response were that the cable shaft fire is bounding and detailed quantification of the fire risk in the MCR in particular, and the Auxiliary Building in general, "would not be beneficial or meaningful." The licensee has considered the potential loss of the MCR to fire and the capability of the SSF in that scenario and found the latter to be sufficient. In the context of the methodology used, the response to RAI #3 is acceptable.

The submittal presented no discussion of the selection of the five "critical zones"and dismissal of the remainder of the plant zones. This led to submittal to the licensee of RAI #6. It asked that the qualitative screening of the remaining plant areas be discussed. The response was to include identification of those areas that were screened and the specific screening basis for each.

The response stated that walkdowns of all areas of the plant in which a fire could affect the safe shutdown of the plant were conducted. The walkdowns included all three units of the plant. Detailed checklists were used to guide the walkdowns of all 139 zones in the plant, which served to verify the existing PRA assumptions and address the Fire Risk Scoping Study Issues [14]. If a fire in a zone would not result in an accident sequence initiating event, the zone was screened. This resulted in the screening of 55 zones. For the remaining 84 zones, each zone plus adjacent zones were examined to determine if damage could occur to equipment necessary to mitigate potential accident sequences. The response notes that the five "critical fire zones" discussed in the submittal were the Turbine Building, Blockhouses, Auxiliary Building, Reactor Building and the 230 kV Switchyard Relay house. These "critical zones" were actually fire areas that were subdivided into zones. 77 of the 139 zones are in the Auxiliary Building, 50 are in the Turbine Building, and the Blockhouses and Reactor Building contain three zones each. This accounts for 134 of 139 zones. The response identifies the remaining five that were not discussed in the submittal. They are the Keowee Hydroelectric Station, the SSF, and the Unit Transformers (Units 1, 2, & 3).

For the five "critical zones" plus the five remaining zones noted above, the response to RAI #6 discusses the results of the evaluation of each zone in terms of the potential for initiating events and number of zones screened. The pertinent sections of the IPEEE submittal for the analysis of the remaining zones are referenced. Other RAI responses related to fires in the Auxiliary Building and Blockhouses are referenced in the response. The response identified each zone and its disposition, and the "critical fire zones" comprise almost all of the individual zones in the plant. On the basis of the information provided, the response to RAI #6 is acceptable.

2.1.4 Fire Occurrence Frequency

After identifying the critical fire zones described in the previous section, the submittal says the second step was to develop an initiating event frequency for each zone. This was only done for the two zones analyzed in detail, i.e, the Turbine Building and the cable shaft in the Auxiliary Building.

The probability of a large cable shaft fire was determined using "... the simplified critical path method ..." of Reference 7. Use of this method led to the identification of TRC3 in Section 2.1.1 of this report. Criticisms of this method include:

- Credit can be taken for automatic detection and manual suppression of a fire twice - once in the incipient stage and again in the developing stage. For Oconee this gives a total probability of suppressing the fire before it envelops the entire area of 0.02. This is not an unreasonable result, but its basis was not developed in terms of the capabilities of existing plant systems. The timing of these events can be important, but is not explicitly addressed in the methodology.

- The probability that the fire will be oxygen starved can be included in the analysis. In the Oconee analysis a value of 0.2 was used based on the presence of only small openings into the cable shaft. This ignores the fact that opening doors to suppress the fire would provide oxygen to the fire.

- The method does not account for the actual layout of critical equipment, e.g., cable trays and bundles in the cable shaft or time to damage. This ignores the possibility of critical damage occurring in the developing fire stage, or even the incipient stage, before suppression can occur.

Based on the equations and data provided in the submittal, the frequency was estimated to be 0.01(apparently per year) and is equivalent to "combustion succeeds" or, in other words, suppression fails. The licensee considers this frequency to be conservative since one of the IPEEE assumptions was that the shielded cable would not self-ignite (an arguable assumption) and no transient combustible material associated with routine maintenance in the cable shaft area could be identified. Since the value given in Table 1.2 of FIVE [12] for non-qualified cable is about 6.0E-03/yr, the value of 0.01 appears to be conservative. The submittal does not state whether the plant has qualified or non-qualified cable. Given the age of the units, it is highly

likely that most, if not all, of the cable is unqualified.

Using an EPRI database (no reference provided, ref TRC5), the licensee provides a frequency of a serious fire involving a PWR steam turbine oil of 1.74E-02/yr. This compares favorably with the value of 1.3E-02 given in FIVE for a turbine generator oil fire. However, the licensee reduced this frequency assuming that only an all-consuming Turbine Building fire needed to be considered. A formula from Reference 9 was used to obtain a frequency estimate for an all-consuming Turbine Building oil fire, based the number of years over which it has not occurred, using a chi-squared distribution. Reference 10 was used as a source for the number of unit years between 1980 and 1993 (range selection basis not discussed) needed for the calculation. Based on this calculation the frequency was reduced to 1.7E-04/yr.

The fact that fire frequencies were only determined for two areas partially resulted from the optimistic fire area screening (ref TRC1, TRC2). In addition, the methods used only provided frequencies for large fires. The potential for smaller fires that occur more frequently and cause significant damage was not discussed. As a result of these factors, the usefulness of the analysis was limited since many risk contributors were not included. The fact that only large fires were considered in the detailed fire analyses was one of the factors that led to the submittal of RAI #1 to the licensee. It asked that smaller fires be considered that cause localized, but still critical, damage to key cables within an area before detection/suppression occur. The response to this RAI is discussed in Section 2.1.6 of this report.

2.1.5 Fire Propagation and Suppression Analysis

As in the case of fire frequency determination, fire propagation and suppression were only considered for the two areas analyzed in detail. In the analysis of Turbine Building fires, no credit was taken for fire barriers or dampers and it was assumed that all Turbine Building equipment is lost. As a result, "... fragilities and failure modes of individual components were not an important part of the analysis." This is consistent with the fact that the submittal contained no discussion that indicated fire modeling was used to determine which targets in the Turbine Building could be damaged by fire, how fires might spread, or the associated timing.

The Turbine Building is equipped with an automatic sprinkler system under the turbines. The operating characteristics of this system are not described. The probability of the failure of this system to prevent the spread of a large fire is estimated to be 0.1 [11]. Applying this factor resulted in an initiating event frequency, including automatic suppression, of 1.7E-05/yr. This was done based on the assumption that this system would assist the firefighters in preventing the spread of the fire to all three units. This treatment of Turbine Building fires is considered to be optimistic since it ignores the risk associated with smaller fires that may cause significant damage and redundantly credits suppression. (Recall that fire suppression activities were already included in the fire frequency determination.) Firefighters are mentioned in the discussion of the Turbine Building fires, but their response capabilities or probability of success are not provided (ref TRC5).

The licensee contends that additional credit for suppression could be justified on the basis of the EPRI fire database. The submittal states that the database shows that only one Turbine Building fire was extinguished by automatic water suppression systems from 1970 to 1989. This is followed by a statement that says it can therefore be assumed that, if more fires had grown larger, the systems would have been more effective. If the suppressed fire had progressed to a large fire, based on the 1304 unit years used in the submittal, the frequency would be 1/1304 = 7.7E-4/yr, somewhat larger than the fire frequency that was used (1.7E-4/yr). This assertion was not well based, but was of no apparent consequence.

Fire detection and suppression features were credited in the analysis of the cable shaft fire scenario. The cable shafts "... are considered to be thoroughly covered by early warning fire detection equipment and a fixed manual suppression system." Automatic detection and manual suppression probabilities factors are credited in two stages of fire growth as part of the scenario analysis which was noted earlier in the discussion of TRC3. Based on the information provided in the submittal, no fire modeling was done to support the analysis of the cable shaft fire scenario.

The submittal states that fire detection and suppression systems were reviewed during the IPEEE walkdown. Except for the systems noted above, none of this information, such as location and type, was included in the submittal. The submittal does not indicate if the suppression systems are designed and maintained in accordance with NFPA standards. In the answers to the questions concerning the fire brigade performance (Section 2.2.4 of this report), no mention was made of potential damage that might be caused by the fire brigade or the time required for some specific actions, e.g., time required to assess the fire (ref TRC5). However, the methodology employed is not sensitive to these details.

2.1.6 Fire-induced Initiating Events and Fire Scenarios

As described earlier, the only two Oconee plant fire zones that were analyzed in detail were the Turbine Building and the cable shaft in the Auxiliary Building. The Turbine Building was analyzed using the Oconee PRA model. The fire sequences for the Turbine Building are included in the submittal. The cable shaft analysis was performed using a method contained in Reference 7. The equations used and the results of the analysis were included in the submittal.

In some cases, spurious operation of equipment due to hot shorts was considered. In the cable shaft fire analysis, it is stated that the probability of a reactor coolant pump (RCP) seal LOCA is largely dependent on hot short and open circuit probabilities. Values of 0.068 for a hot short and 0.932 for an open circuit were cited [13] in the submittal and used in the analysis. In the Reactor Building qualitative analysis, the pressurizer PORV was mentioned as being susceptible to opening due to a hot short. Isolation valves LP-1 and LP-2 could also spuriously open due to a fire, but the mechanism is not specifically identified. Since a "total space involvement" fire is assumed, the probability of electrical valve actuation may be dependent on other fire-induced failures. Assuming an independent failure probability may introduce optimism into the result.

In the cable shaft fire analysis, automatic detection and manual suppression, each with a success probability of 0.9, are credited. Automatic suppression is apparently not available so no credit is given. Assuming fuel is available for the fire with a 0.98 probability, these factors, plus the fire frequency, produce a "probability of a developing fire H" of 1.9E-03. To calculate a "probability of total space involvement", the factor H is further reduced by crediting additional probabilities of successful detection (0.99) and successful manual suppression (0.9). Based on the limited openings for air intake into the fire zone, it is also estimated that the probability of oxygen being available for the fire is 0.2. Applying these factors results in a probability of total space involvement M of 4.2E-05.

One cable shaft fire (Accident Sequence #1) is analyzed as a loss of component cooling and failure of the HPI pumps to run. The additional failure included is the human error accounting for failure to deploy to the SSF, initiate RCP seal injection, and initiate auxiliary service water (ASW). No SSF random hardware failures are mentioned in the discussion of the analysis. Values for the probabilities of all of these events are included in the submittal, but no sources are referenced for the failure of component cooling and failure of the HPI pumps to run. The validity of using the HPI pump and component cooling probabilities in this sequence in conjunction with a fire that involves the entire cable shaft was not discussed. The quantification of the SSF human error is, according to the submittal, based on features of the SSF procedure, but no details were provided (ref TRC5). The CDF for the resulting sequence is 1.11E-09. This low value results primarily from the factor M and the probability of failure to man the SSF (6.0E-03).

The second sequence considered (Accident Sequence #2) is a seal LOCA which results from HPI failure due to pump starvation which, in turn, is caused by the #1 pump continuing to run due to an open circuit and the other two pumps starting due to hot shorts as discussed above. Loss of component cooling and the human error to account for failure to deploy to the SSF and initiate RCP seal injection and ASW are also included in this sequence, but, as in the first sequence, SSF hardware failures are not. As in the first sequence, the validity of using the HPI pump and component cooling probabilities in this sequence in conjunction with a fire that involves the entire cable shaft was not discussed. More documentation could have been provided (ref TRC5). The CDF for the resulting sequence is 7.6E-11. Again, the factor M and the failure to man the SSF have a significant influence on this value. The possibility of the cable shaft fire resulting in other loss of coolant scenarios, such as a fire-induced PORV opening, were not discussed in the submittal. In addition, it should be noted that in both sequences that were analyzed the licensee assumed that the SSF is physically independent of the control room and thus will not be affected by the cable shaft fire.

The treatment of the cable shaft fire raised concerns that led to the submittal of RAI #1 to the licensee. The concerns included crediting detection and suppression twice in the fire progression, limiting the fires considered to those that fully engulf an area, assuming self-ignition of shielded cable was not credible (even though the plant almost certainly contains some non-qualified cable), failing to consider the potential for SSF hardware failures, evaluating only two

cable shaft fire scenarios, and failing to consider the possibility of spurious component operation due to hot shorts.

As part of the response to RAI #1, the licensee stated that weaknesses in the cable shaft fire analysis were identified. The deficiencies were: (1) estimation of the fire frequency, (2) fire brigade response time, (3) fuel loading for fire propagation, (4) Component Cooling System susceptibility to fire, (5) SSF failure probability, and (6) operator recovery of the HPI pumps. To account for these weaknesses, the cable shaft fire frequency and associated CDFs for the two sequences discussed earlier were recalculated. For both sequences the incipient fire frequency was lowered slightly (4%). A fire brigade response time of 10 minutes rather than three minutes was used, but the fuel loading was reduced based on the electrical cabinet configurations. The overall combustibility of the cables ".. was found to be relatively low." However, as discussed subsequently, this was based on the incorrect assumption that the cable is equivalent to IEEE-383 qualified cable. The net result, of these changes was that the frequency of a cable shaft fire that would cause total damage increased by a factor of three, i.e., from the original value of 4.2E-05 to 1.3E-04 which is considered to be a reasonable value.

In both accident sequences it was assumed in the revised analysis that the fire would fail Component Cooling. (The failure probability in the original analysis was 0.07.) The possibility of additional SSF failures or recovery were also considered in the revised analysis. These changes, including the revised fire frequency, resulted in the Accident Sequence #1 CDF increasing from 1.1E-09/yr to 6.6E-08/yr and the Accident Sequence #2 CDF increasing from 7.6E-11/yr to 8.9E-08/yr. Thus, the revised CDF due to a fire in the cable shaft is about 1.6E-07 per yr. The revised analysis, though not completely presented in the response (ref TRC5), is considered to be more realistic than the original analysis in the IPEEE submittal. The responses to the specific concerns cited in the RAI are discussed in the following paragraphs.

A. The chosen analysis method credits detection and suppression twice as fully independent steps in the fire progression, which can result in optimistic credit for detection/suppression.

In response to this concern, the licensee discusses the possible intent of the originators of the NUREG/CR-0064 [7] methodology. The response states that only a 20% chance of successful manual suppression is credited for each stage in the revised assessment. Hence, the total probability of failure for manual suppression is no lower than about 64%. Overall the response to the concern is considered to be adequate.

B. The only cable shaft fire that has been considered is a fully engulfing fire. This fire may bound the damage state for the plant, but it may not be the most significant risk contributor. Apparently, no consideration has been given to smaller fires that might cause localized, but still critical, damage to a subset of cables before detection/suppression can intervene.

The response to this concern states that it would be very difficult to determine the effects of smaller fires in specific cable shaft locations. It is noted that the probability that a fire grows into

a fully involved fire was increased in the revised analysis, as discussed earlier. The response concludes that it seems unlikely that the fraction of cable fires associated with a particular portion of the cables could be more important than the large fire assessed. This conclusion involves the potential for fire propagation (ref TRC4) and neglects the potentially higher frequency, but consequential small fires. This is not considered to be an adequate response.

C. Self-ignition of shielded cable was assumed to not be credible. Given the age of the Oconee units, the presence of cables that are not IEEE-383 qualified should be assumed; hence, self-ignited cable fires should also be considered.

The response to this concern states that the fire damage threshold for the cable shaft fire is uncertain, "but considering the robust cable design and previous experience, significant cable damage is not likely until the fire progresses to the large fire stage." The results of fire tests are discussed that, the licensee concludes, make fire in the cable unlikely. It is also stated that cable of the same design specifications and manufacturer passed the IEEE-383-1975 Flame Test. This information does not address the basic ignition issue raised in this part of the RAI and therefore constitutes a weakness.

D. Failure to achieve shutdown using the SSF was apparently considered as a HEP related to manning the SSF. It appears that potential system, control, and/or instrumentation hardware failures, including both fire-related damage and other failures (random failure on demand, maintenance outages, etc.), that might render the SSF functions unavailable or unreliable were not considered.

The response to this concern notes that hardware-related failure modes of the SSF systems were included in the revised analysis discussed previously. The SSF systems were designed and constructed to be completely independent of the cable shaft, control room, and other areas of the auxiliary building. There is no power or control cabling or other equipment required for the SSF in this area, so control system interactions or other fire-related failures are not relevant. (Only the west penetration room contains cables for the SSF. These are discussed in the response to RAI #2.) Overall, this response is considered to be acceptable.

E. Apparently, only two scenarios were analyzed, and both involved a reactor coolant pump (RCP) seal LOCA. Other scenarios should also be considered. For example, general transients, hot shorts producing a LOCA, etc.

The response to this item states that other scenarios were evaluated (including total loss of feedwater and loss of all ac power), but because it is expected that feedwater will remain available to the steam generators in the event of a fire in this area (backup feedwater is also available from the SSF ASW pump), only scenarios involving failure of the RCP seals were found to be important contributors to the frequency of core damage for this area. It is also stated that a thorough evaluation of the potential for fire-induced LOCAs has been made, including those involving a pressurizer PORV. The latter scenario is discussed in some detail. Overall,

this response is considered to be satisfactory.

F. It does not appear that the analysis has included the consideration of hot shorts that may lead to the spurious operation of systems and components including MOVs and PORVs.

The response to this concern states that hot shorts that could cause loss of HPI and component cooling to the RCP seals were considered. However, the analysis did not account for hot shorts that could send spurious signals that could cause motor operated and air operated valves to go to undesired positions. The issue addressed by this part of the RAI is one of those being addressed cooperatively by NRC and industry. Thus, the licensee has responded to this concern within the limits of the current state-of-the-art.

For the Turbine Building fire, spread throughout the building (large fire) is assumed as discussed previously. The suppression system under the turbine is credited with limiting the fire spread, but not extinguishing it. It is stated that the sequences generated take credit for the SSF and it is assumed that the fire will not effect proper operation of the facility. Independent failures of SSF equipment are included in the sequences. As in the case of the cable shaft fire, a human error accounting for failure to deploy to the SSF, initiate RCP seal injection, and initiate ASW to the steam generators is included in the Turbine Building fire sequences. However, a value of 1.0E-2 is used for the Turbine Building fire instead of the value of 6.0E-3 that was used for the cable shaft fire. The licensee stated that this human error probability (HEP) is time independent, so the use of different values for the two fires should have been supported (ref TRC5).

Additional items were identified as associated with TRC5. No event or fault trees were included in the submittal. This made the fire scenarios more difficult to evaluate. Although LOSP was mentioned as a possible fire consequence that was covered by the PRA analysis, no results were discussed in the submittal.

Except for the Turbine Building fire, multi-unit impacts due to fires were not discussed. Based on the detailed analysis descriptions and other portions of the submittal, many compartments in one unit impact the fire assessment in the other unit. A list of the systems that are shared between the units was not provided, but it is stated that many buildings/areas are shared, including the Control Room and the SSF, in addition to the Turbine Building. Thus, fires in these areas could cause core damage in more than one unit. Multi-unit scenarios resulting from propagation of fire, smoke, and suppressants between fire zones containing equipment for different units were also not mentioned. As a result, RAI #5 was submitted to the licensee asking that multi-unit fire scenarios be evaluated. Issues to be addressed included the potential for simultaneous trip demand for more than one unit, the need for cross-connects to a sister unit for certain fires, and fires requiring simultaneous MCR evacuation for more than one unit.

The licensee response identified the important systems that are shared between two or more units. It states that the potential for a fire to affect multiple units or important equipment in adjacent zones was considered both in the IPEEE Fire Walkdowns and in the determination of

critical fire areas that were included in the CDF analysis. The licensee's conclusion that the all-consuming Turbine Building fire would be critical in terms of multiple unit effects was repeated. As stated in the IPEEE submittal and repeated in the response, the Unit 1 and 2 Blockhouse fire was considered to be bounded by this fire (RAI #4) and the MCR fire risk was judged to much less than that due to the cable shaft fire (RAI # 3). Both of these responses are consistent with the concerns discussed in TRC2.

The 230 kV Switchyard Relay House was identified as an area containing shared systems. A fire in this area could result in a LOOP and a loss of power from the Keowee overhead line. However, this event was considered to be accounted for in the PRA internal events analysis because the LOOP frequency included fire events. The response discusses four areas within the Auxiliary Building which contain equipment or cabling that could, if damaged, impact multiple units. Based on TRC2 (bounding arguments), lack of fire induced reactor trips, the ability to safely shutdown the unit, and/or negligible core damage potential, the risks to multiple units due to fires in these areas were not considered to be significant unless the fire were very large and propagated from the zone of origin to an adjacent zone in another unit. After considering these areas, the Turbine Building fire was determined (again) to be the only significant event involving multiple units. The safe shutdown capabilities of the SSF were also reiterated.

The response concluded with the following responses to the four RAI #5 issues:

A. Plant staffing requirements provide for both SSF activation and fire brigade response to a multi-unit fire event. The same crew that activates the SSF for one unit can support all three units if required by an event.

B. The safe shutdown paths (SSF systems) at Oconee do not call for any cross-connections to other units. The PRA fire analysis does not take any direct credit for assistance from other units.

C. The fire walkdown team considered the potential propagation of fire, heat, smoke, and suppressants between zones for multiple units. No problems or issues regarding risk important systems/components were identified. However, several recommendations for improvements in the Oconee fire protection features and plant response, including some related to smoke migration and water spray effects, were documented in the IPEEE submittal.

D. Units 1 and 2 at Oconee share an MCR. However, each unit has its own cable shaft and cable rooms. A multi-unit fire can be successfully responded to as noted above.

Although some aspects of the issues raised by RAI # 5 were, per TRC5, not fully covered in the response, overall it is considered to be acceptable as an explanation and expansion of the material in the IPEEE submittal.

2.1.7 Quantification and Uncertainty Analysis

As discussed earlier in this report, only the Turbine Building and the cable shaft in the Auxiliary Building were modeled in detail. Of these two, only the Turbine Building had a core damage frequency (CDF) greater than 1.0E-6/yr due to fires. Since the Turbine Building is shared, the CDF of 5.8E-06/yr applies to all three units. (Note that in two places in the submittal a slightly smaller CDF of 5.0E-06/yr is quoted for this area.) In the response to RAI #1, a revised CDF of 1.6E-07/yr for the cable shaft fire was provided, but this value may be optimistic based on the analysis method used (ref TRC3). Estimates of the CDF for other fires that could lead to core damage of more than one unit were not provided. The numerical results were either given or inferred as follows:

Area	frequency (/yr)	CCDP	CDF(/yr)
Turbine Building	1.7E-4	3.0E-2	5.1E-6
Unit 1,2 Blockhouse (estimated)			<1.3E-6
Cable Shaft	1.3E-4	1.2E-3	1.6E-7

The Turbine Building initiating event, TBFIRE, combined with failure of the SSF diesel generator (DG) is the dominant fire sequence. It comprises 29.7% of the total CDF. Other major sequences include SSF ASW pump fails to start on demand (12.0%), SSF DG in maintenance (9.4%), and train 2 refrigerant compressor fails to start (7.8%). (The train 2 refrigerant compressor apparently is part of the SSF HVAC air conditioning system.) Operators failing to deploy to the to the SSF is the eighth ranked sequence (3.9%). Failure probabilities and unavailabilities for the SSF DG, ASW pump, and train 2 compressor are included in list of fire sequences. The values for the SSF DG appear to be conservative, but data sources are not referenced for any of the events (ref TRC5).

Based on the results of the fire analysis, it did not appear that there are postulated fires that lead directly to core damage. The submittal presented no information related to an uncertainty analysis of the results.

2.1.8 Sensitivity and Importance Ranking Studies

A sensitivity study was done to determine the impact of credit taken for extra time to perform SSF related human actions. Two additional human errors are included in time critical transient sequences which do not include any fire sequences. (The submittal does not state where the critical transient sequences originated.) If the SSF human actions used in "the other transient sequences", which are also not defined in the submittal, are included in the fire sequences, the resulting total cut set frequency increases by about 17% to 6.8E-06 per year. The submittal states that this is low compared to the contribution from other external events.

2.2Special Issues

As a part of the IPEEE fire submittal, the utilities were asked to address a number of fire-related issues identified in the Fire Risk Scoping Study (FRSS) [14] and USNRC Generic Safety Issues (GSI). Specific review guidance on these issues is found in Reference 6.

2.2.1 Decay Heat Removal (USI A-45)

As discussed in Generic Letter 88-20 [4] and NUREG-1407 [5], USI A-45 which is associated with the adequacy of decay heat removal (DHR) at nuclear power plants is subsumed into the IPE submittals. A submittal meeting the intent of Generic Letter 88-20, Supplement 4 is assumed to satisfy the requirements of USI A-45. Specifically, the fire assessment presented in the IPEEE submittal should address the adequacy of long-term decay heat removal in the event of fires.

The Oconee submittal simply states that this issue is sufficiently treated in the IPE submittal. It was not examined as part of the IPEEE review, so, for example, the time period for successful DHR was not noted in the review of the submittal. Also, (1) the effects of postulated component failures on mitigating systems and (2) the components (safety or non-safety grade) used at Oconee also were not discussed in the submittal.

2.2.2 Effects of Fire Protection System Actuation on Safety-related Equipment (FRSS, GSI-57, MSRP)

This issue is associated with the concern that traditional fire PRA methods have generally considered only direct thermal damage effects. Other potential damage mechanisms have not been addressed, such as smoke and the potential that the activation of fire suppression systems, either as part of actual fire fighting or spuriously, might result in damage to plant systems and components. In general, this is an area where the database on equipment vulnerability is rather sparse. The analytical results obtained for resolution of the issue, subsumed by GSI-57, identified the dominant risk contributors as: (1) Seismic-induced fire plus seismic-induced suppressant diversion and (2) Seismic-induced actuation of the fire protection system (FPS). The NRC anticipated that the licensee would conduct seismic/fire walkdowns to assess (1) whether an actuated FPS would spray safety-related equipment, and (2) whether some protective measures to prevent the same could be instituted. The results could be documented in the IPEEE submittal.

The walkdown team investigated the potential risk to safety related equipment due to water discharge from sprinkler heads and fire hoses. The potential for fire suppression water to migrate from the zone of origin to another zone due to dripping, spraying, etc. and cause damage to redundant safety related equipment was also evaluated. This resulted in most zones in the Turbine and Auxiliary Buildings being identified as zones where water could migrate to other zones. As a result, changes to the plant pre-fire document will be made and sprinkler head changes were recommended. The submittal did not indicate that credit was taken for these

changes in the fire analysis.

The submittal states in Section 4.8.5 that GSI-57 was examined in conjunction with the plant walkdowns. This resulted in a recommendation to replace the open head sprinklers in the cable room and equipment rooms with closed head sprinklers. No other cost effective modifications related to GSI-57 were identified.

The potential for ruptured vessels or piping due to seismic events that could spray or flood essential equipment in "vulnerable areas of the plant" was considered during the walkdowns as part of the seismic assessment. The results were not noted in the fire portion of the submittal and a cursory review of the seismic analysis did not reveal any results of this evaluation. An on-going review of relays which could potentially lead to problems due to relay chatter was mentioned in the submittal, but was not related to any potential effects on fire suppression systems.

Smoke effects were evaluated for equipment that may be susceptible to smoke accumulation. Electrical devices such as contacts, terminations, relays, and pressure and temperature transmitters were included. Enclosed motors and pumps were not. No results or conclusions from these evaluations were provided in the submittal.

2.2.3 Fire-induced Alternate Shutdown/Control Room Panel Interactions (FRSS, GSI 147)

The issue of control systems interactions is associated primarily with the potential that a fire in the plant, i.e., main control room (MCR), might lead to potential control systems vulnerabilities. Given a fire in the plant, the likely sources of control systems interactions are between the control room, remote shutdown panel, and shutdown systems. Specific areas that should be addressed in the IPEEE fire analysis include 1) Electrical independence of the remote shutdown control systems; 2) Loss of control equipment or power before transfer; 3) Spurious actuation of components leading to component damage, LOCA, or interfacing LOCA; and 4) Total loss of system function. It is anticipated that the licensee's submittal will describe its remote shutdown capability including the nature and location of the shutdown station(s) and the types of control actions which can be taken from the remote panel(s).

The utility submittal states that Oconee has a Standby Shutdown System (SSS). The Safe Shutdown Facility (SSF) was designed and constructed to implement this system. The SSF is located in the plant yard. Because the SSF is physically and electrically independent of the control room and auxiliary shutdown panel (ASP), the licensee states that the control systems interaction issue is considered to have been addressed for the plant. The operator actions required to transfer control to the SSF or use the ASP are not discussed, although failure to follow procedural guidance to man the SSF was considered as a potential human error which can lead to an RCP LOCA. The relationship between the SSF and ASP was not described. How transfer of control to the SSF is performed (there is apparently a transfer panel in the Auxiliary

Building) and the equipment required or specific actions involved was only briefly discussed in the submittal.

Two types of LOCAs due to a fire in containment were considered, but dismissed, as follows:

- A pressurizer PORV opening due to a hot short could be closed from outside the Reactor Building by removing power (method and success probability not discussed).

- An interfacing LOCA due to the spurious opening of valves LP-1 and LP-2 as the result of a fire in the Reactor Building is not a concern based on a previous analysis (no details provided).

Loss of control equipment or power before transfer; spurious actuation of components leading to component damage; and total loss of system function are not discussed in the submittal. The processes used to verify electrical independence and evaluate the level of indication and control of remote shutdown control and monitoring circuits were also not discussed.

2.2.4 Smoke Control and Manual Fire Fighting Effectiveness (FRSS, GSI-148)

Smoke control and manual fire fighting effectiveness is associated with the concern that nuclear power plant ventilation systems are known to be poorly configured for smoke removal in the event of a fire, and hence, a significant potential exists for the buildup of smoke to hamper the efforts of the manual fire brigade to promptly and effectively suppress fires. Sensitivity studies have shown that prolonged fire fighting times can lead to a noticeable increase in fire risk. Smoke, identified as one of the major contributors to prolonged response times, can also cause misdirected suppression efforts and hamper the operator's ability to safely shut down the plant.

Some effects of smoke were considered as discussed in Section 2.2.2 of this report. Section 4.8.4 of the submittal discusses smoke generation and migration effects. Each zone was examined to determine if a fire could generate significant smoke. Fixed and transient sources were considered. Where automatic suppression systems are installed, they "... are expected to mitigate smoke generation in the zone of origin."

In zones where smoke may be generated, the walkdown identified adjacent, and in some cases, remote zones where smoke migration might affect redundant safety related equipment. This was also discussed in the response to RAI #5 as noted in Section 2.1.6 of this report. For these zones, the potential for smoke isolation, control, and/or exhaust using the existing ventilation systems was investigated. If the ventilation was unable to control or mitigate the smoke, the walkdown checklist triggered an evaluation of fire brigade response and effectiveness in controlling the smoke.

The walkdown team identified zones in the Turbine and Auxiliary Buildings where smoke could migrate to other zones. As a result, smoke control recommendations and precautions will be added to the plant pre-fire plan document. It was also recommended that a wall between two zones be

sealed. The walkdown for the other fire zones where appreciable smoke could be generated concluded that "... existing smoke control is sufficient to preclude unacceptable damage. There were no cases identified where smoke effects could be considered a significant risk contributor." Significantly, the Control Room was not specifically mentioned as being covered by this statement. If it is included, Control Room evacuation due to smoke affecting operator effectiveness is apparently not considered to be a credible event. Operator action effectiveness in relation to safe shutdown procedures and training is not mentioned in the submittal.

Several topics were not discussed in the submittal section addressing this FRSS issue. These included fire reporting, the use and availability of portable fire extinguishers, and plant procedures for reporting fires, including plant communication. Fire brigade topics not discussed included brigade makeup, equipment, and physical condition requirements; classroom and equipment training; periodic and unannounced drills, including execution of fire preplans; and training records.

With respect to the items listed on page C-23 of the submittal review guidance [6], the submittal provided no information on the potential for fire-fighting efforts to jeopardize the separation between redundant trains, or fighting the fire or getting to the fire causing fire barriers to be opened or breached. The inclusion of the availability of fixed manual suppression systems in the model was not discussed. Also, the time to locate the fire once the fire brigade has arrived on the scene was not explicitly considered, nor was the time to extinguish or gain substantial control of the fire once it is located.

2.2.5 Seismic/Fire Interactions (FRSS, MSRP)

The issue of Seismic/Fire Interactions primarily involves three concerns. First is the potential that seismic events might result in fires internal to the plant. Such threats might be realized from inadequately secured liquid fuel or oil tanks, through breakage of fuel lines, or through the rocking of unanchored electrical panels (either safety or non-safety grade). The second concern is the potential that seismic events might render fixed fire suppression systems inoperable. This could include detection systems, fixed suppression systems, and fixed manual fire fighting support elements such as the plant firewater distribution system. The third concern is that a seismic event might spuriously actuate fixed fire detection and suppression systems. The spurious operation of detectors might both complicate operator response to the seismic event and/or cause the actuation of automatic fire suppression systems. Actuation of a suppression system may lead to flooding problems, habitability concerns (in the case of CO_2 systems), diversion of suppressants to non-fire areas rendering them unavailable in the event of a fire elsewhere, the potential over-dumping of gaseous suppressants resulting in an over-pressure of a compartment, and spraying of important plant components. It had been anticipated that a typical fire IPEEE submittal would provide for some treatment of these issues through a focused seismic/fire interaction walkdown.

Each zone was examined to determine the potential for a seismic event to damage equipment or components which would result in fire ignition, propagation, or increased fire hazard. This was accomplished by identifying high voltage electrical equipment (> 600V), locating flammable or

combustible gas piping, and equipment containing more than five gallons of flammable or combustible liquids. Where these were identified, a more detailed analysis by the fire IPEEE team and the seismic walkdown team was performed. The submittal identifies some recommended improvements which apparently resulted from this analysis.

The reactor coolant pump motors were identified as high energy electrical equipment items which are not seismically mounted. As discussed in Section 2.1.3 of this report, fires in these motors were judged by the licensee not to be a concern.

The walkdown identified numerous pieces of equipment as having potential fire/seismic impact. The documents in which they are identified were referenced, but no consolidated equipment list was provided in the submittal. The submittal states that many of the items were screened based on location relative to PRA seismically-assured equipment. "Equipment not screened by the fire team and PRA analysts was evaluated for impact by the seismic team." However, the results of this evaluation were not discussed in the sections of submittal describing the fire study.

The locations of non-seismic fire protection control panels and actuation devices were reviewed to determine if a seismic event would cause inadvertent system operation. Deluge valves for important transformers were identified as actuation devices which are not seismically qualified. These were determined by the licensee to not be a concern due to the probable unavailability of offsite power after a seismic event and the ability of the transformers to operate even with the water spray systems in operation.

The possibility of a seismic event displacing cabinets and causing cable damage which could lead to fires was not specifically discussed in the submittal.

2.2.6 Adequacy of Fire Barriers (FRSS)

The common reliance on fire barriers to separate redundant components needed to achieve safe shutdown has elevated the risk sensitivity of fire barrier performance. Degraded fire barrier penetration seals and unsealed penetrations in some barriers can contribute to this source of fire risk, since fires in one area might impact other adjacent or connected areas through the spread of heat and smoke. In general, it is expected that a utility analysis would provide for some treatment of such potential by considering that (1) manual fire fighting activities might allow for the spread of heat and smoke through the opening of access doors, and (2) the failure of active fire barrier elements such as normally open doors, water curtains, and ventilation dampers might compromise barrier integrity.

According to the submittal, the licensing basis of the Oconee fire protection program is that all three units can achieve safe shutdown following a fire in any fire zone of the plant. Barrier failures that could lead to failure of redundant trains of equipment required for safe shutdown is a recognized concern. It is stated that Oconee uses the Standby Shutdown System (SSS) approach. This was not described in the submittal, but consists of responding to accidents by activating the SSF which is separate from other plant systems and is specifically designed to meet the applicable Appendix R

requirements. Due to the SSS approach, the submittal states there are few barrier failures that could result in fire damage to redundant trains of safe shutdown equipment. Further, the potential for fire barrier failure was not considered in the Oconee fire PRA for the following reasons:

A. The Turbine Building fire considered in the analysis is assumed involve the entire building, no credit is taken for barriers. The SSF is credited on the basis that it will not be affected by the fire.

B. In the cable shaft fire scenario, the HPI pumps and SSF are credited. The effect of the fire on the HPI cables in the shaft is considered so the effect of barrier failure which could lead to HPI failure was not considered. As in a., the SSF is credited on the basis that it will not be directly involved in the fire.

C. The wall between the east and west penetration rooms is a three hour rated fire barrier which is inspected. A fire in one of these rooms is considered to be bounded by the cable shaft fire. (ref TRC2) Due to "intermittent" barriers and spatial separation, it is considered highly improbable that a fire would spread between the Turbine Building and the west penetration rooms or cask decon rooms.

With the exception of the one inspected barrier noted above, the submittal does not specify the fire barriers and components such as fire dampers, penetration seals, and barrier fire doors that are included in the plant surveillance program. The frequency of inspection of fire rated barriers, fire doors, penetration seals, fire dampers, etc, was not provided. It was not indicated if penetration seals have been evaluated in connection with concerns identified in various NRC Information Notices, such as IN 88-04. Similarly, fire damper installation evaluations to respond to concerns such as those identified in IN 83-69 and IN 89-52 were not mentioned.

2.2.7 Effects of Hydrogen Line Ruptures (MSRP)

The use of flammable gases in the plant, including hydrogen, introduces the potential that a rupture of the gas flow lines might lead to the introduction of a serious fire hazard into plant safety areas. It had been anticipated that a typical fire IPEEE analysis would include the consideration of such sources in the analysis.

The effects of hydrogen line ruptures were considered as part of the fire-seismic walkdowns as noted in Section 2.2.5 of this report.

2.2.8 Common Cause Failures related to Human Errors (MSRP)

Common cause failures resulting from human errors include operator acts of omission or commission that could be initiating events or could affect redundant safety-related trains needed to mitigate other initiating events. It had been anticipated that a typical fire IPEEE analysis would include the consideration of such failures in the submittal.

The Oconee IPEEE submittal includes a discussion of the human recovery actions and methods used in the fire analysis. Human reliability is considered in the Turbine Building fire sequences. The

errors considered are dynamic human errors and latent (pre-initiator) human errors. Latent human errors considered include the SSF, Auxiliary Service Water (ASW) System, reactor coolant makeup (RCM), or diesel subsystems left unavailable (no reason is given, but probably following test and/or maintenance) and the containment left unisolated. The only dynamic (post-initiator) error considered is a failure to follow procedural guidance to man the SSF. This event models the part of the failure of both the RCM and ASW which is not time dependent (i.e., error in performing, not diagnosis, due to time available), but different values were used in the Turbine Building and cable shaft fire analyses.

Additional discussion of the human actions modeled in response to fires is contained in Section 2.1.6 of this report.

2.2.9 Non-safety Related Control System/Safety Related Protection System Dependencies (MSRP)

Multiple failures in non-safety-related control systems may have an adverse impact on safety-related protection systems as a result of potential unrecognized dependencies between control and protection systems. The licensee's IPE process should provide a framework for systematic evaluation of interdependence between safety-related and non-safety related systems and identify potential sources of vulnerabilities. It had been anticipated that the fire IPEEE analysis would include the consideration of such dependencies in the submittal.

The submittal contained no information related to this issue except as described in Section 2.2.3 of this report.

2.2.10 Effects of Flooding and/or Moisture Intrusion on Non-Safety and Safety-Related Equipment (MSRP)

Flooding and water intrusion events can affect safety-related equipment either directly or indirectly through flooding or moisture intrusion of multiple trains of non-safety-related equipment. This type of event can result from external flooding events, tank and pipe ruptures, actuations of the fire suppression system, or backflow through part of the plant drainage system. It had been anticipated that the fire IPEEE analysis would include the consideration of such events in the submittal.

The effects of automatic fire suppression system actuation, fire hose operation, and pipe rupture on safety/safe-shutdown related equipment are discussed in Section 2.2.2 of this report. The other possible sources of or effects due to flooding noted in the previous paragraph were not discussed in the submittal.

2.2.11 Shutdown Systems and Electrical Instrumentation and Control Features (SEP)

The issue of shutdown systems addresses the capacity of plants to ensure reliable shutdown using safety-grade equipment. The issue of electrical instrumentation and control addresses the functional capabilities of electrical instrumentation and control features of systems required for safe shutdown, including support systems. These systems should be designed, fabricated, installed, and tested to quality standards and remain functional following external events. It had been anticipated that the

fire IPEEE analysis would include the consideration of this issue in the submittal.

The portions of this issue that were covered in the submittal are described in Section 2.2.3 of this report.

2.3 Containment Performance Issues Unique to Fire Scenarios

The submittal only briefly discusses containment performance in the context of the potential effects of fires. Containment isolation and safeguards assumptions are stated to be the same for the fire analysis as for other PRA sequences. The Oconee PRA is referenced for the containment safeguards analysis which is discussed briefly below. The submittal states that the IPEEE walkdown did not result in the identification of any additional fire related containment failure modes.

A screening analysis of containment penetrations was performed in the PRA to determine which penetrations, if failed, could lead to significant release pathways. The penetrations, including their associated piping and valves, were found by the licensee to be able to withstand a seismic event. Potential seismic/fire effects were not discussed.

The cabinets containing the Emergency Safeguards Features Actuation System (ESFAS) were evaluated for functional ruggedness. The panelboards and motor control centers providing power to actuate the valve solenoids and motors were analyzed and evaluated via plant walkdowns. Two failure modes were identified, but neither was discussed in terms of seismic/fire interactions.

External events (presumably including fire) were judged to have no unique impact on containment safeguards. That is, the containment response did not reflect any new cut sets that were not already included in the internal event sequences. The effects of fire-induced failures on containment heat removal were not specifically discussed.

2.4 Plant Vulnerabilities and Improvements

In the Rev. 2 Oconee PRA, a number of fire areas were screened and two were, as discussed previously, analyzed in detail. The licensee did not state in the submittal what constituted a vulnerability. However, based on the entire analysis, the licensee concludes there are no fundamental weaknesses or vulnerabilities in terms of severe accident risk. In addition, the licensee states that Oconee Nuclear Station poses no undue risk to the public health and safety.

Based on the results of the fire analysis, the licensee developed 13 recommendations which the submittal, dated 12/95, stated are currently being reviewed or are in progress. Three of these recommendations involve changes to documentation (pre-fire plan and fire protection drawings). Improvements in the seismic resistance of combustible storage containers (cabinets, lockers, and drums) are proposed by another three recommendations. Other recommendations include sealing a wall to limit smoke migration, replacing open head sprinklers with a closed head design in several areas, installation of fire detectors in one section of the Turbine Building, removal of an unnecessary Unit 2 room smoke purge fan, and evaluation of a water suppression system for the turbine bearings.

The licensee did not state that any of the recommendations were credited in the fire analysis.

As noted previously, the total CDF due to fires for Oconee was estimated to be 5.8E-06/yr. No CDF estimates were provided for individual units. The Turbine Building fire is the primary risk. The top sequence involves a run failure of the SSF diesel. Its failure probability is given as 0.111. The cable shaft in the Auxiliary Building is the only other area for which a CDF was determined. In the response to RAI #1, a revised CDF of 1.6E-07/yr for this area was provided.

3.0 CONCLUSIONS AND RECOMMENDATIONS

The fire assessment in Revision 1 of the Oconee PRA was the basis for the quantitative fire analysis of the IPEEE. This assessment is an update of the EPRI NSAC-60 Oconee PRA. The IPEEE submittal, supplemented by RAI responses, responds to the Generic Letter and includes information relevant to FRSS issues, Generic Safety Issues, Unresolved Safety Issues, and Multiple Systems Response Program issues. Strengths of the submittal include the following:

Strengths

- In zones where smoke may be generated, the walkdown identified zones where smoke migration might affect redundant safety related equipment. For these zones, the potential for smoke isolation, control, and/or exhaust using the existing ventilation systems was investigated. If the ventilation was unable to control or mitigate the smoke, the walkdown checklist triggered an evaluation of fire brigade response and effectiveness in controlling the smoke.

- Treatment of human response and recovery actions in the PRA modeling of the Turbine Building fire. Human actions were also included in cable shaft fire analysis.

- Fire study results were used to update the plant PRA model.

The review of the original submittal raised a number of questions. Subject areas found deficient during review of the submittal led to requests for additional information. The licensee resolved most of the outstanding questions, with remaining weaknesses noted in the discussion of the RAI responses. One such weakness follows from the response to RAI #1, which cited flame propagation test results in response to assumptions regarding self-ignited cable fires. The cited tests do not indicate other relevant properties, e.g., ignition temperatures, self-ignition properties, or thermal damage temperatures.

Most of the remaining weaknesses noted in the review of the Oconee submittal and RAI responses can be traced to the technical reviewer concerns (TRCs) cited earlier, e.g., the Bounding Scenario screening. An important consequence of the limited analysis performed and limited scenarios considered is that fire study may be incomplete in the PRA sense. This may make it less useful in resolving risk-based issues. Further interaction with the licensee is not recommended however.

The reviewers recommend that a sufficient level of documentation and appropriate bases for analysis have been established to conclude that the Oconee IPEEE fire submittal has substantially met the intent of the IPEEE process.

4.0 REFERENCES

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2. Letter from David E. LaBarge, NRC/NRR, to Duke Energy Corporation, "Request for Additional Information - Individual Plant Examination of External Events (IPEEE), Oconee Nuclear Station, Units 1, 2, and 3," dated January 5, 1999.

3. Letter from W. R. McCollum, Jr., Duke Power, to U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Docket Nos. 50-269, -270, -287, Oconee IPEEE Analysis - Response to Request for Additional Information dated January 5, 1999."

4. USNRC, "Individual Plant Examination of External Events for Severe Accident Vulnerabilities - 10 CFR §50.54(f)," Generic Letter 88-20, Supplement 4, April 1991.

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7. Berry, D. L., and Minor, E. E., "Nuclear Power Plant Fire Protection - Fire Hazard Analysis (Subsystems Study Task 4)," Sandia Laboratories, NUREG/CR-0654, SAND 79-0324, September 1979.

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11. Holmes, Wayne D., "A Methodology for the Assessment of Risk of Major Fire Loss in Multi-Unit Turbine Generator Buildings," SFPE TR84-9.

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13. Kazarians, M., and Apostolakis, G., "Fire Risk Analysis for Nuclear Plants," University of California School of Engineering and Applied Science, UCLA-ENG-8102, NUREG/CR-2258, September 1981.

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OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS

TECHNICAL EVALUATION REPORT FOR

HIGH WINDS, FLOODS, AND OTHER EXTERNAL EVENTS ANALYSIS

Enclosure 4

TECHNICAL EVALUATION REPORT

REVIEW OF OCONEE INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS SUBMITTED ON HIGH WIND, FLOOD AND OTHER EXTERNAL EVENTS BY THE OFFICE OF NUCLEAR REACTOR RESEARCH

1.0 SCREENING OF EXTERNAL HAZARDS

The licensee used the progressive screening approach described in NUREG-1407 to screen external hazards and found that there were no other plant-unique external events that pose a significant threat of severe accidents within the context of the NUREG-1407 screening approach.

2.0 HIGH WINDS

The Oconee final safety analysis report (FSAR) gives the design basis wind velocity as 95 miles per hour (mph) based on a 100 year mean recurrence interval. Since all Class 1 structures at Oconee are designed for at least 95 mph, the probability of damage to important structures or components from non-tornadic (straight) wind at Oconee is low compared to that of tornadoes. In addition, the licensee evaluated the impact of hurricanes on Oconee. Since Oconee is located more than 220 miles from the nearest coastal area, the probability of severe wind damage at Oconee due to hurricanes is very low.

The licensee provided an update to an earlier tornado study for Oconee (NSAC/60). The licensee estimated that the CDF initiated by tornadoes was about 1.3E-5/RY. The licensee identified that the SSF has the highest impact on the tornado CDF and recommended that station personnel study enhancements to the natural disaster procedure to provide guidance to ensure that prompt activation of the SSF is achieved following a tornado event. The licensee determined that this review should also consider the adequacy of sheltering plans of all plant personnel needed during the post-event recovery stage following a tornado event that might cause some structural damage to the plant.

3.0 EXTERNAL FLOODS

When it was determined that the licensee's original IPEEE submittal did not provide sufficient information on GSI-103, "Design for Probable Maximum Precipitation (PMP)," the staff sent the licensee an RAI. In response, the licensee referred to an updated flood study that includes the Keowee dam and reservoir. The updated flood study used the criteria in the hydro-meteorological reports that were listed in GL 89-22. The PMP for Oconee was estimated to be 26.6 inches within 48 hours. The results of the updated flood study showed that the Keowee reservoir could accommodate the reservoir flooding resulting from a PMP. The licensee has also assessed the effects of greater roof ponding levels due to a PMP.

The licensee estimated that the CDF due to external flooding initiated by a random failure of the Jocassee Dam is about 7E-6/RY and noted that the external flooding CDF is dominated by failures of SSF when floods exceed the 5-foot SSF flood barrier.

4.0 TRANSPORTATION AND NEARBY FACILITY ACCIDENTS

The licensee evaluated aircraft impact accidents, road and rail accidents, and fixed facility accidents, including industrial facilities, military facilities, and pipeline accidents.

Regarding the aircraft impact accidents, the licensee noted that there were four airways in the vicinity of the plant site. The licensee estimated the probability of an aircraft crashing into the site was about 1.1E-8/RY. Therefore, the licensee concluded that aircraft accidents could be screened out.

The effects of a marine transportation accident on the plant CDF are also minimal because there is little commercial marine transportation activity near the plant.

Regarding rail accidents, the licensee noted that the closest rail lines come within about 6 miles of the plant site and would not significantly affect the operation at Oconee.

With respect to highway trucking accidents, the licensee noted that two state highways pass within one mile of the plant site. The licensee determined that a toxic gas release from a highway accident would have a minimal effect on the control room. In addition, the licensee examined the effects of an explosion from a highway accident and determined that

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The licensee evaluated accidents from nearby facilities and determined that there were no manufacturing or military facilities within five miles of the site. Although hazardous chemicals are shipped to and from several industrial facilities located between 7 and 10 miles from the plant site, the licensee determined that none of them would affect the operation of Oconee.

Regarding a release of toxic chemicals in the event of onsite hazardous material accidents, the licensee noted that chlorine and hydrazine were stored onsite. Because there are chlorine detectors onsite, and the control room is a self-contained, controlled environment furnished with self-contained breathing equipment, the effects of a toxic gas release onsite would have a minimal effect on control room personnel.

Regarding an explosion accident from a release of flammable material stored onsite, the licensee noted that propane and hydrogen are stored onsite. The propane tanks were found to be capable of withstanding a design basis earthquake without sliding or overturning. To prevent inadvertent contact with heavy equipment or other vehicles, robust barriers have been installed around each propane tank. Therefore, the licensee concluded that an explosion from a propane tank accident is unlikely. With respect to a hydrogen explosion accident, the licensee noted that all areas, with the exception of letdown storage tank (LDST) rooms, have adequate ventilation to maintain hydrogen concentration below 0.1 percent. The licensee made two recommendations to modify

the ventilation system exhaust in each LDST room and to provide guidance to operators to prevent hydrogen buildup. The first recommendation has been implemented. The LDST rooms were screened out during the fire/seismic review because an explosion or fire in these rooms would have little impact on safety-related systems.

Regarding gas pipeline rupture accidents, the licensee noted that natural gas lines are located about 3.5 miles from the plant site. The gas lines have an operating pressure of about 400 pounds per square inch. The licensee concluded that a rupture of these lines would not affect the operation of Oconee. In addition, the licensee noted that there are two off-site propane storage facilities near the plant site. Because of the distances between these facilities and the plant site, the licensee concluded that an explosion at either of these propane storage facilities would not affect the operation of Oconee.

5.0 OTHER PLANT-UNIQUE EXTERNAL EVENTS

The licensee provided specific discussions on 20 other external events (e.g., avalanche; costal erosion; drought, high summer temperatures, low lake or river water level; fog; forest fire; frost, hail, snow, ice cover; hurricane; landslide; lightning; meteorite; intense precipitation; river diversion; sandstorm; seiche; soil shrink-well consolidation; storm surge; tunami; turbine-generated missiles; volcanic activity; and waves). The licensee concluded that there were no plant-unique external hazards at Oconee.

6.0 GENERIC SAFETY ISSUES

(1) GSI-103, Design for Probable Maximum Precipitation

The licensee has assessed the effects of flooding and roof ponding as a result of Probable Maximum Precipitation and provided information in the RAI responses dated March 31, 1999, and October 4, 1999. The staff finds that the licensee's GSI-103 evaluation is consistent with the guidance provided in Section 6.2.2.3 of NUREG-1407. Therefore, the staff considers this issue resolved.

(2) GSI-156, Systematic Evaluation Program (SEP)

The licensee's IPEEE submittal and other associated documentation were reviewed for information directly addressing the following HFO-related SEP issues: dam integrity and site flooding in Section 5.2 of the IPEEE; site hydrology and ability to withstand floods in Section 5.2 of the IPEEE; industrial hazards in Section 5.3 of the IPEEE; tornado missiles in Section 5.1.2 of the IPEEE; severe weather effects on structures in Section 5 of IPEEE; and design codes, criteria, and load combinations in Section 3.1 of the IPEEE. Based on the results of the IPEEE submittal review, the staff considers the licensee's process capable of identifying potential vulnerabilities associated with these issues. On the basis that no potential vulnerability associated with these issues was identified in the IPEEE submittal, the staff considered the HFO-related aspects of these issues resolved.

(3) GSI-172, Multiple System Responses Program (MSRP)

The licensee's IPEEE submittal contains information directly addressing the

following HFO-related MSRP issue: effects of flooding and/or moisture intrusion on non-safety related and safety-related equipment in Section 3.1.2.3 of the IPEEE. Based on the overall results of the staff's IPEEE submittal review, the staff considers that the licensee's process is capable of identifying potential vulnerabilities associated with this issue. On the basis that no potential vulnerability associated with this issue was identified in the IPEEE submittal, the staff considers the HFO-related aspects of this issue resolved.

7.0 CONCLUSIONS

The staff has determined that the IPEEE submittal meets the intent of Supplement 4 to GL 88-20, for the high winds, floods, transportation and other external events. The licensee found no vulnerabilities with respect to HFO events.

ATTACHMENT

DUKE ENERGY CAROLINAS, LLC, CONTRACT NE 23546 – LETTER REPORT AND TRANSMITTAL OF SUPPORTING DATA – ARES TASK NO. 0630302.01

D 9

ARES CORPORATION

Applied Research & Engineering Sciences

VIA E-MAIL – ptfarish@duke-energy.com

07SA01014

January 29, 2007

Mr. Paul T. Farish
Duke Energy Corporation
526 South Church Street
Mail Code: EC08I
Charlotte, NC 28202-1904

SUBJECT: DUKE ENERGY CAROLINAS, LLC, CONTRACT NE 23546 –
LETTER REPORT AND TRANSMITTAL OF SUPPORTING DATA –
ARES TASK NO. 0630302.01

Dear Mr. Farish:

This letter provides a summary of the revised fragility evaluation results for Jocassee Dam conducted under the subject contract and transmits the supporting data developed during the project. First, however, there are some caveats imposed on the study that must be stated:

1) Jocassee Dam is founded on the same bedrock as Oconee, thus we have used the Oconee seismic hazard (EPRI, 1989) as the basis for the revised Jocassee fragility. One of the major reasons for the change in Jocassee Dam fragility (from the 1981 evaluation results that from the current fragility results used for Jocassee dam in the Oconee PRA) is the frequency content of the seismic hazard. Being a very large dam, Jocassee is characterized by a low fundamental frequency (0.75 -1.5 Hz), thus the major portion of the dam response is controlled by the low frequency content of the hazard. The prior evaluation (consistent with procedures used at that time) assumed motion content that is significantly higher in the 0.75-1.5 Hz range than the 1989 EPRI seismic hazard. Thus, the revised fragility results are directly associated with the frequency content of the 1989 EPRI seismic hazard. If the Oconee seismic hazard is revised in the future, the seismic fragility of Jocassee Dam must be reassessed.
2) Jocassee is designated as a rockfill embankment dam. However, the core transitions from a central region with slightly-clayey-silty-sand to outer regions of silty-sand and certain portions of the shell are designated as random rock which is actually a mixture of rock and silty-sand. The presence of sands within the dam requires the consideration of the liquefaction potential of these materials in a saturated state. The placement and compaction of the core materials was closely controlled during the construction of the dam using Proctor tests. It is judged that the core materials have sufficient densification to preclude the initiation of liquefaction during shaking. The saturated random rock mixture, while highly compacted, did not have test control and thus does not have the same level of

densification assurance as the does the core. The presence of the random rock material implies that a limitation on input motion is necessary for a judgment of low liquefaction potential. However, it should also be noted that the location of the zone of saturated random rock material within the dam would limit the unlikely event of liquefaction to small, isolated zones. This assessment of a low liquefaction potential for any susceptible dam materials is qualitative based on judgment and opinion. Any quantitative assessment of the liquefaction potential of susceptible materials would require the availability of certain test data for dam materials that are not currently available.

Basic Procedure

Jocassee Dam was constructed using three basic materials which are designated as: rockfill, random rock, and core materials. Based on review of the technical literature, ONS FSAR, test data contained in the original design report, and the available construction documentation, the density and range of strength and physical properties were established for each material. Upper, median, and lower strength bounds (approximate one sigma) for the shear strength, maximum value of shear modulus, shear modulus degradation as a function of shear strain, and material damping as a function of shear strain, were established. The failure mechanism of the dam is taken as the sliding instability of a soil mass down the dam embankment slope. In general, soil masses that include the crest are considered as potentially capable of causing loss of reservoir. The initiation of slope failure using pseudo-static acceleration levels (along with dead weight loading) is then found using conventional slope stability analysis methods (accomplished using the program UTEXAS4). These acceleration levels are designated as the yield acceleration levels at which sliding of the soil mass *begins*. The material strength bounds can then be used to establish a seismic capacity model (where capacity is defined as initiation of sliding) characterized by a median yield acceleration of the soil mass and the associated variability. The seismic demand is determined by the local response of the soil mass region of the dam slope which has sliding potential. The response of the dam, given the base motion (bedrock), is found by analysis using a finite element model of the dam. The analysis procedure used (by the program QUAD4M) is very similar to the traditional analysis of soil deposits using the SHAKE program except that it is two dimensional and is conducted in the time domain. If the median EPRI hazard input motion is scaled (a PGA = 0.24 g is the reference motion level) until the local critical region of the dam (i.e., the potential sliding mass) has a response level that equals the median capacity of sliding initiation, that scale factor is the demand factor. This process can be repeated using each one sigma material property value to establish the variability of the demand scale factor that gives a response level equal to the capacity (approximate second moment method).

Once the demand level associated with the initiation of sliding has been established, the input motion can be scaled beyond this level with the resulting sliding displacement of the slope mass.

If the sliding mass is assumed to not appreciably change the response of the dam, then the portion of the response acceleration greater than the yield acceleration level can be double integrated to obtain the sliding displacement of the slope mass. This is the classic Newmark analogy of a block sliding down a plane with stick-slip motion. A slipping motion of two feet has been accepted by FERC as a conservative criterion in prior seismic evaluations of embankment dams. The 1981 seismic fragility evaluation of Jocassee Dam assumed a median failure slippage of three feet based on an estimate of filter fracture displacement. International agencies use a value of 1 m sliding displacement as acceptable for dam safety evaluations.

Results

The fragility of the dam is characterized by the fragility of the downstream embankment slope. The median yield level acceleration of the downstream slope mass has been determined to be 0.216 g. This is an acceleration value that the dam *response* must exceed before any sliding can occur. The median response levels of the downstream mass that is equal to the sliding initiation level is obtained by scaling the median 0.24 g EPRI hazard motion by a factor of three. *Thus, the median fragility level of the dam for initiation of sliding is 0.72 g.* The randomness, characterized by the lognormal standard deviation, β_r, is found to be approximately 0.29 and is driven by the variability in the hazard spectral shape. The overall uncertainty, characterized by the lognormal standard deviation, β_u, is found to be 0.43. Thus, the HCLPF (sliding initiation) = $0.72e^{-1.65(\beta r+\beta u)} = 0.22$g.

When the input motion was further scaled beyond the level associated with initiation of sliding it was found that it was very difficult to obtain a significant level of sliding displacement using the rock hazard motion associated with the Oconee site. Since the Oconee Hazard is only defined to a PGA level equal to 1g, it was decided to limit the input motion scaling to less than 2 g. Given that the sliding criterion for fragility determination is chosen as 2 inch, *the median fragility level of the dam would be 1.64 g.* In this case, the HCLPF would represent a high confidence of a low probability that the sliding displacement of a slope mass exceeds two inches. The randomness, characterized by the lognormal standard deviation, β_r, is found to be approximately 0.35. The overall uncertainty, characterized by the lognormal standard deviation, β_u, is found to be 0.67. Thus, the HCLPF would represent a high confidence of a low probability that the sliding displacement of a slope mass exceeds one inch and is given by:

HCLPF (one inch sliding) = $1.64e^{-1.65(\beta r+\beta u)} = 0.305$g. The limiting of the sliding displacement to two inches insures that the shear stress to effective overburden pressure ratio is sufficiently low to limit any potential liquefaction in the compacted sand regions of the dam.

Attachments A through H summarize the data sources used and the details of the calculations. The firm of Devine Tarbell & Associates (Charlotte, NC office) was retained for geotechnical services including review of available source documents on the construction and subsequent FERC evaluations of Jocassee Dam, judgments associated with liquefaction potential and regional material properties, slope stability analyses, and Newmark sliding displacement analyses. Their letter report is included as Attachment I. The supporting calculations noted in that letter will be sent under separate cover. Please contact me at (714) 556-5700 if you have any questions concerning this letter report and attachments.

Sincerely,

Kelvin Merz
Technical Consultant

KLM:daw

cc. Brian Chrisman, DTA

Attachments:

A. Project Background
B. Input Ground Motion
C. Strength Values
D. Material Values
E. Identification of Failure Surfaces
F. Development of QUAD4M Model for Jocassee Dam
G. Determination of Sliding Deformations
H. Determination of Jocassee Dam Fragility
I. Devine Tarbell & Associates Letter Report

Attachment to 07SA01014
January 29, 2007

ATTACHMENT A
PROJECT BACKGROUND

Jocassee Dam, with a height of a 385 feet and a crest length of approximately 1,750 feet, is a zoned embankment dam, with rock-fill shells and a clayey-silt and silty-sand center core supported by a rock foundation with a maximum transverse base dimension of approximately 1500 feet. The dam is located approximately 8.5 miles north of the Oconee Nuclear Station which uses the adjacent Lake Keowee as the cooling source. The dam was designed in the late 1960s with work completed in 1973 to impound the 7500 acre Lake Jocassee. Associated with the dam is the 610-megawatt Jocassee Hydroelectric Station that uses Lake Keowee as the lower lake and Lake Jocassee as the upper lake to operate as a pumped-storage generating facility. Since failure of Jocassee Dam can affect the level of Lake Keowee, and potentially flood the Oconee site, it is considered as a component in the seismic probabilistic risk assessment (PRA) of the Oconee Nuclear Station.

Prior Fragility Estimate

The median seismic fragility value (PGA = 0.49 g) currently used in the Oconee PRA for Jocassee Dam is based on the evaluation prepared by Veneziano (Reference A1, 1981). This evaluation was formulated in a manner such that the result is independent of the hazard. Several potential slip surfaces were postulated with the slope stability evaluated with the Simplified Bishop Method considering the horizontal earthquake force as a pseudo-static load.

In the 1981 evaluation, the response of the dam was considered as an amplification factor (γ_a) times the peak ground acceleration. This amplification factor incorporates both the structural amplification characteristics of the dam and the normalized hazard spectra amplitude at the estimated fundamental frequency of the dam (1/0.68 = 1.47 Hz). The basis of this amplification factor is attributed to uncited work by Law Engineering. Since this work was conducted prior to the 1989 EPRI hazard study (Reference A2), the effect of the dominant high frequency content of the hazard study for the Oconee site (and vicinity) was not considered in the fragility evaluation. It is assumed that the amplification factor was derived based on the low frequency content of WUS earthquakes and not the high frequency content now considered as probable for EUS rock sites.

In the 1981 evaluation, the permanent displacement of the sliding failure mass was estimated by an additional factor (γ_d) times the amplification factor. This factor appears to be based on an empirical modification of a theoretical model for estimating permanent displacements which is reasonable but not documented. The fragility of the dam was then defined as the probability statement $P[D > d|A_R]$, where D is the permanent displacement of the slope mass, d = 36 inches (assumed overtopping displacement), and A_R is the PGA of the foundation. The fragility was actually calculated using the alternate expression $\int_0^\infty P[F < 1|A_W = \gamma\, A_R]\, f_\gamma(\gamma)\, d\gamma$, where F is the factor of safety generated by the pseudo-static stability analysis, A_W is the acceleration of the sliding mass given as a factor times the PGA of the foundation $\gamma\, A_R$ where $\gamma = \gamma_a\gamma_d$. All variables were assumed to be log-normal with estimated median values and variability accounting for both randomness and knowledge uncertainty (the 1981 evaluation denotes the variability due to randomness, or aleatory

uncertainty, as "frequentist uncertainty" and the variability due to knowledge uncertainty, or epistemic uncertainty, as "nonfrequentist uncertainty").

Revised Fragility Estimate

In the past 25 years, the practice for earthquake evaluation of embankment dams has changed considerably. While the basic fundamentals governing the determination of slope stability remain the same, software has replaced the older hand calculation techniques and has allowed a more complete analytical approach to a basically non-linear problem. The increased computation capability allows the consideration of several variables to find the critical failure modes which in the past was accomplished by conservative judgment and experience. Thus, there is a need to revise the seismic fragility estimate for Jocassee Dam using state-of-the-art methods in order to reflect the increased knowledge of embankment dam behavior during an earthquake and the increased understanding of seismic hazard in the EUS. This attachment provides a summary of the results of a revised fragility evaluation for Jocassee Dam. This revised seismic evaluation encompassed the following steps:

1. Gather and evaluate all existing design calculations, drawings, geology reports, geotechnical reports, FERC submittals, lake level variability and piezometric surface, etc.
2. Generate median and uncertainty values for material properties for the core, filters, rock-fill and foundation rock for Jocassee Dam
3. Establish free-field ground motion to be used for the seismic fragility evaluation based on 1989 EPRI hard rock hazard for ONS:
    a. Evaluate UHS shapes for both median and uncertainty calculations;
    b. Account for a weathered rock layer, either in the dam model or the modification of the free-field motion; and
    c. Generate time histories for free-field input motion.
4. Conduct study to identify failure modes for the dam at different levels of shaking:
    a. Liquefaction evaluation/assessment;
    b. Pseudo-static assessment of slope stability using UTEXAS4 program;
    c. Identification of 6 critical failure surfaces and determination of yield acceleration for each surface; and
    d. Sensitivity studies varying material properties and also varying phreatic surface assumptions as required.
5. Time history analyses of dam using modified QUAD4M Code:
    a. Perform time history analyses of 2D dam model; several response time histories are required to assess the scaling of input level effects;
    b. Perform sensitivity studies on the dam material properties;

c. Modify the QUAD4M code, if necessary, to incorporate the proper characterization of dam response to high frequency input; and

d. Define final set of slope failure mechanisms.

6. Develop Yield Acceleration levels and Earthquake-induced Crest Displacements:

a. Yield acceleration levels for three slope failure models and three material property cases (9 cases) plus any variance in phreatic surfaces;

b. Utilize Newmark sliding block method to estimate displacements for variety of material and phreatic surface combinations (up to 45 calculations estimated).

7. Generate seismic fragility:

a. Consider alternate failure definitions;

b. Incorporate the variability based on approximate second order methods; and

c. Provide median fragility level and associated B_U and B_R values.

References

A1. Veneziano, D., "Seismic Fragility Curves for Jocassee Dam and Oconee Dikes", report prepared for Law Engineering Testing Company, June, 1981.

A2. Electric Power Research Institute, "Probabilistic Seismic Hazard Evaluations at Nuclear Power Plant Sites in the Central and Eastern United States", EPRI NP-6395-D, April, 1989.

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ATTACHMENT B
INPUT GROUND MOTION

UHS Defined for Rock Outcrop

Reference B1 chose the 10,000 year median Uniform Hazard Spectrum (UHS) presented in Reference B2 for the Oconee Nuclear Station (ONS) site as the representative spectral shape to be used in the seismic portion of the Oconee PRA. Since Reference B2 identifies ONS as a rock site, this UHS was associated with an outcrop of the sound hard rock used as the foundation support material for the primary ONS structures. Jocassee Dam is located approximately 8.5 miles north of the Oconee Nuclear Station and is founded on the same bedrock formation as ONS. Thus, the UHS used as the reference motion in the ONS PRA is also applicable as the reference motion for the fragility evaluation of Jocassee Dam.

Since the fragility level is determined by scaling the reference input motion until the response of the structure (dam, in this case) causes a defined failure mode, it is important that the frequency content of the reference motion not change appreciably with hazard level as the motion is scaled. Figure B-1 shows the 1989 EPRI uniform hazard spectra (Reference B2) for the Oconee site. The Oconee PRA has also consistently used the median spectral shape associated with the 1.0E-04 probability of exceedance level to determine fragility levels. Figure B-2 provides a comparison of the normalized (by PGA) median spectral shapes for several probability levels. This plot indicates that the use of the median spectral shape for the 1.0E-04 probability of exceedance level is a reasonable compromise for determination of a fragility function. It can also be noted from Figures B-1 and B-2 that low frequency systems (less than 2 Hz) will respond at acceleration levels substantially less than the PGA level and that the higher modes of the dam are likely to be excited by the characteristic EUS high frequency content.

For the seismic portion of the Oconee PRA, it has been assumed that the hazard curves are defined for the bedrock with the PGA placed at 50 Hz. In Reference B2, the PGA value is not associated with a stated high frequency cutoff value, thus 50 Hz was chosen in Reference B6 as the PGA frequency limit. More recent hazard studies for the Eastern United States, following procedures detailed in Reference B3, have associated the PGA with 100 Hz; however, these studies are not consistent with the assumptions used in the Oconee PRA.

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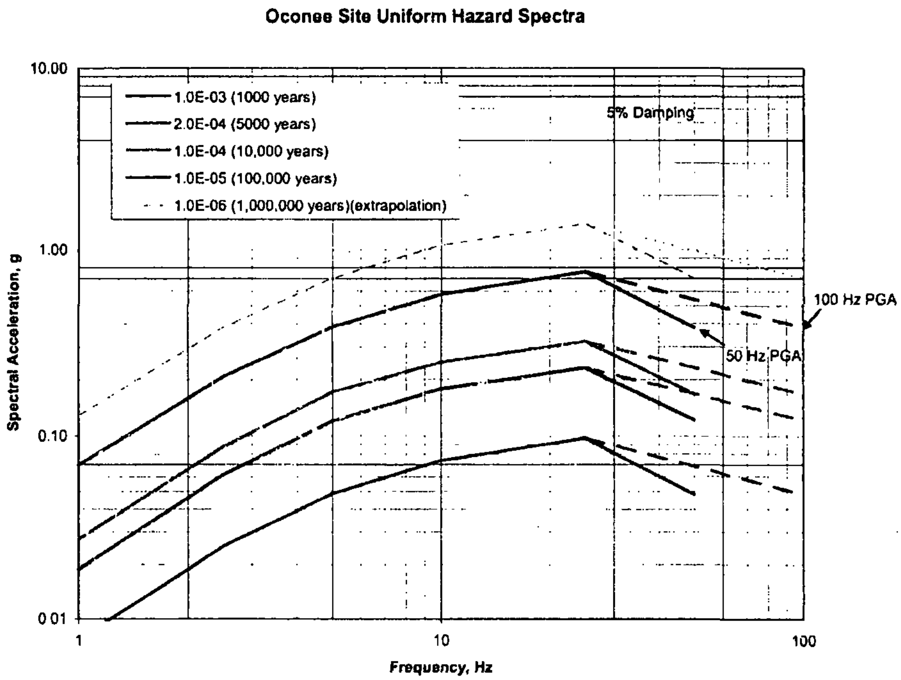

Figure B-1 Uniform Hazard Spectra for Oconee Site (EPRI, 1989)

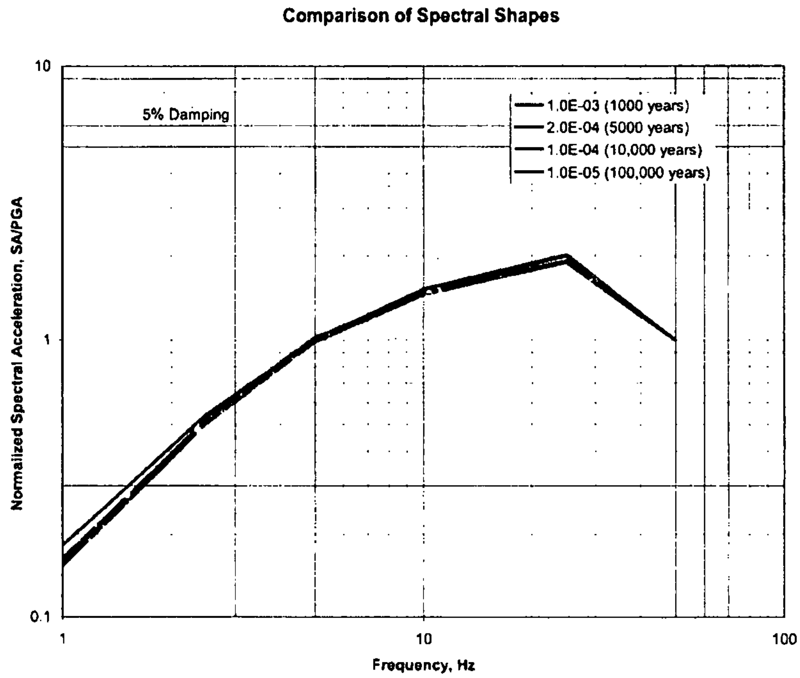

Figure B-2 Comparison of Uniform Hazard Spectral Shapes for Oconee Site (EPRI, 1989)

Reference B2 did not consider vertical ground motion differences, thus for prior ONS PRA studies, the vertical spectrum has been assumed to be equal to the horizontal spectrum. Reference B3, however, provides specific guidance for estimating vertical UHS spectra based on the ratio of vertical to horizontal spectral values. Reference B4 used the guidance of Reference B3 to define vertical UHS for use in determination of ONS overburden response. Figure B-3 shows the range of ratio of vertical to horizontal spectral values (as a function of horizontal PGA) as a function of frequency recommended in Reference B3.

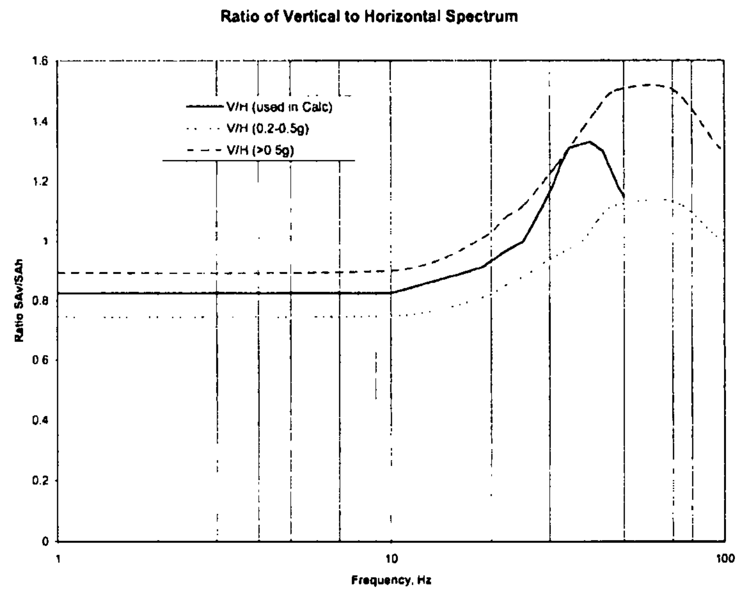

Figure B-3 Ratio of Vertical and Horizontal Spectra Recommended in NUREG-6728

As can be noted from Figure B-3, the values range from 0.8 to 1.3 and are maximum at approximately 60 Hz. In order to be consistent with the placement of the PGA at 50 Hz, as done in Reference B1 for the ONS PRA evaluations, the average ratios were logarithmically compressed in the range of 25-100 Hz to the range of 25-50 Hz. Figure B-4 (Reference B4) compares the vertical and horizontal rock UHS for the ONS site, anchored to a horizontal PGA value of 0.24 g (a reference motion level chosen in Reference 6), which result from this characterization.

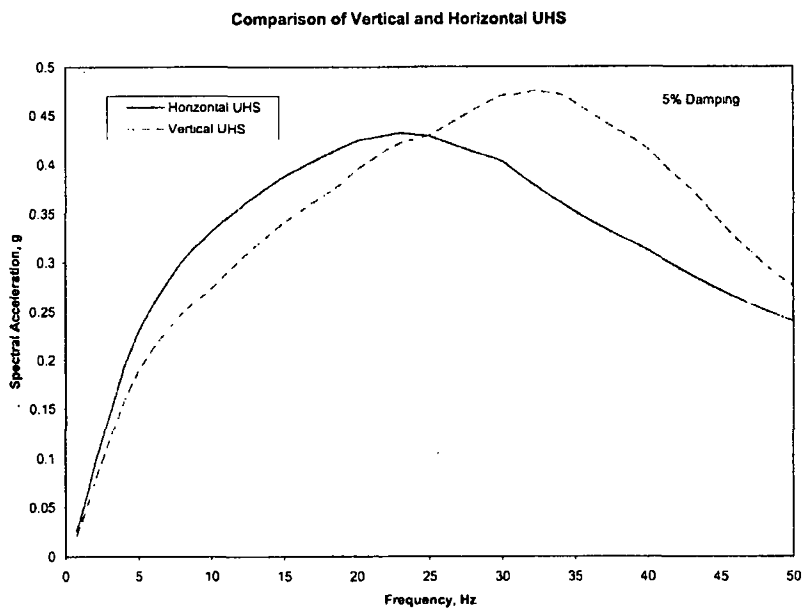

Figure B-4 Horizontal and Vertical Rock UHS Spectra Defined for the ONS Site (Anchored to Horizontal PGA = 0.24g)

Reference B3 also recommends the use of deaggregated hazard spectra to determine motions for sites affected by both near, low Magnitude, and far, more distant, larger Magnitude earthquakes. Reference B5 indicates that the controlling earthquake for the Oconee site is a single 5.6 Magnitude earthquake at a distance of 15 km. Thus, deaggregation of the hazard is not required for the ONS site.

UHS Compatible Time-Histories

Reference B6 generated rock UHS compatible time-histories (two horizontal and one vertical time series with 2048 acceleration points each at 0.01 sec intervals) for use in PRA evaluations of the primary ONS structures and housed equipment. These time history input motions have approximately 20 sec total duration (5 sec rise time, 10 sec strong motion duration, and 5 sec decay time) and are statistically uncorrelated in accordance with the requirements of Reference B7. Figure B-5 compares the response spectra generated from the horizontal time histories obtained from Reference 6. These time-histories were developed with a PGA of 0.24 g at 50 Hz (reference level chosen in Reference B6) and, as can be noted, they envelop the rock UHS shape. Since it was important to not overdrive soil materials in the ONS overburden, these initial motions were then modified in Reference B4 with a variety of filtering software packages until a closer fit to the UHS spectrum was obtained as also shown in Figure B-5. These filtered rock motions are judged to be applicable for the response evaluation of Jocassee Dam.

Reference B3 provides alternate acceptance criteria for spectrum compatible time histories which differ from the acceptance criteria presented in Reference B7. The recently published Reference B8 has adopted the acceptance guidance for spectrum compatible time histories provided in Reference B3. In general, the requirements for checking the power spectral density functions computed from the acceleration time histories are no longer required. In lieu of power spectral density functions, the response spectra are required to be computed at much smaller increments of frequency (100 points per frequency decade) and the following acceptance criteria:

1. Total motion duration of at least 20 sec.
2. Computed response spectrum values (5% damping) shall not be less than 90% of the target response spectrum
3. No more than four adjacent computed response spectrum values on either side of a given frequency may be less than the target response spectrum
4. Computed response spectrum values (5% damping) shall not be greater than 130% of the target response spectrum
5. Correlation coefficients between pairs of records shall not exceed a value of 0.30

The spectra computed from the revised UHS time histories are compared to the 0.9 and 1.3 bounds in Figure B-6. The statistical independence of the initial time-histories was assumed to not be affected by the filtering of the revision process.

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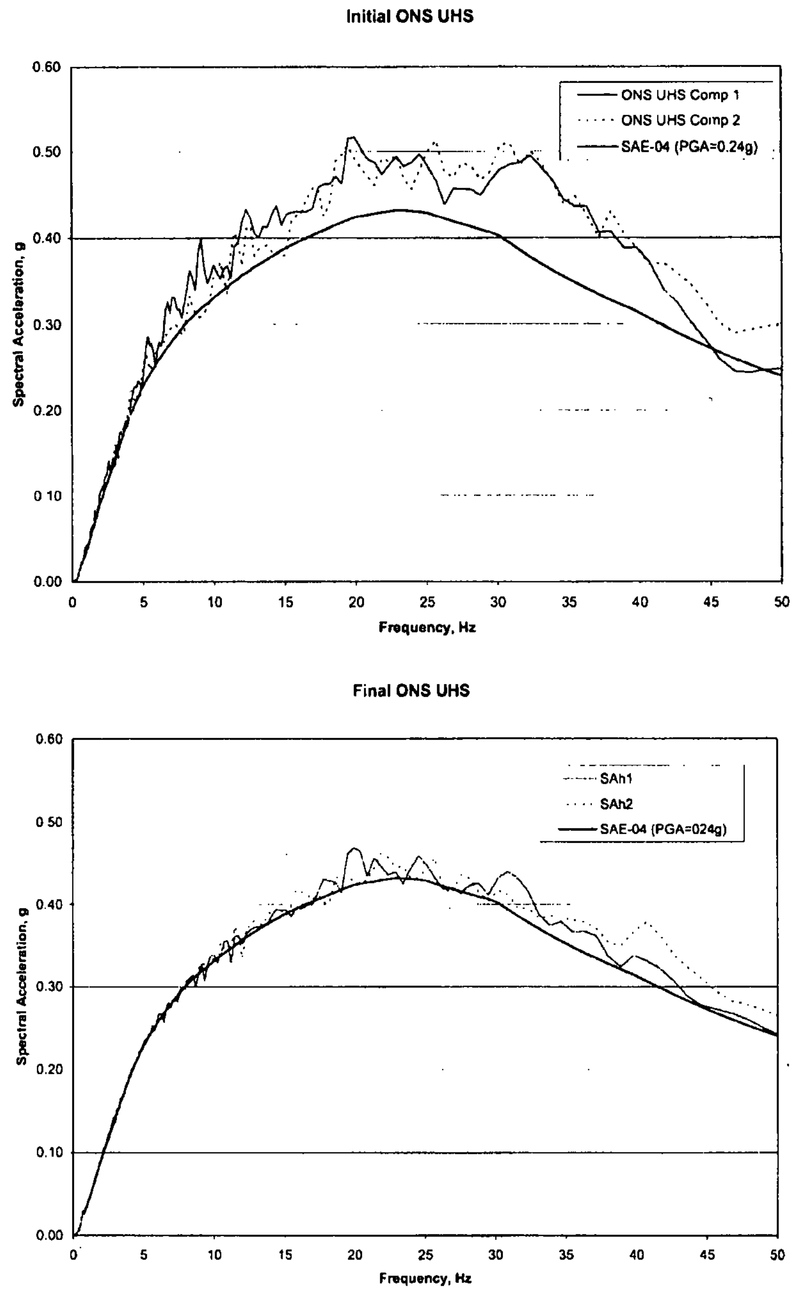
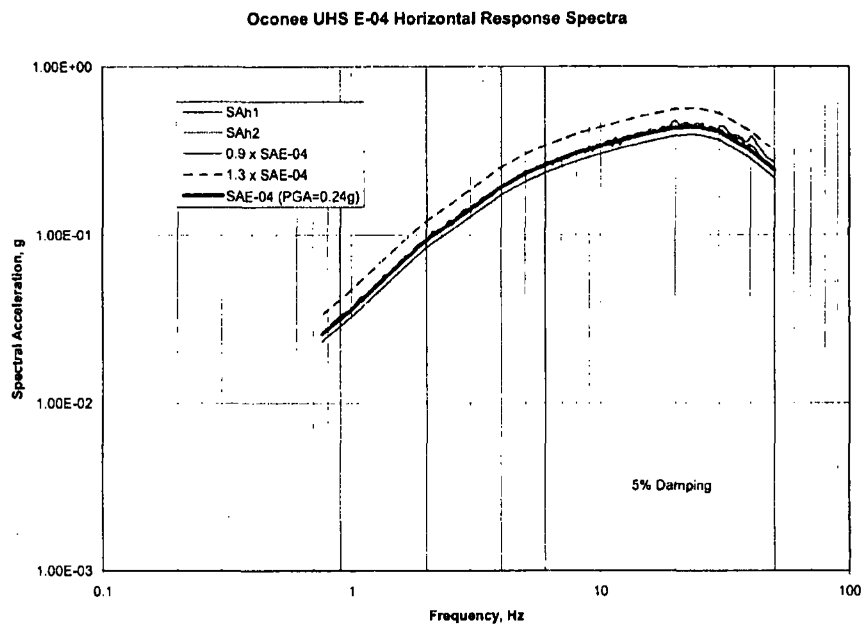


Figure B-5 Comparison of Spectra Generated from Initial UHS Time Histories and Revised UHS Time Histories



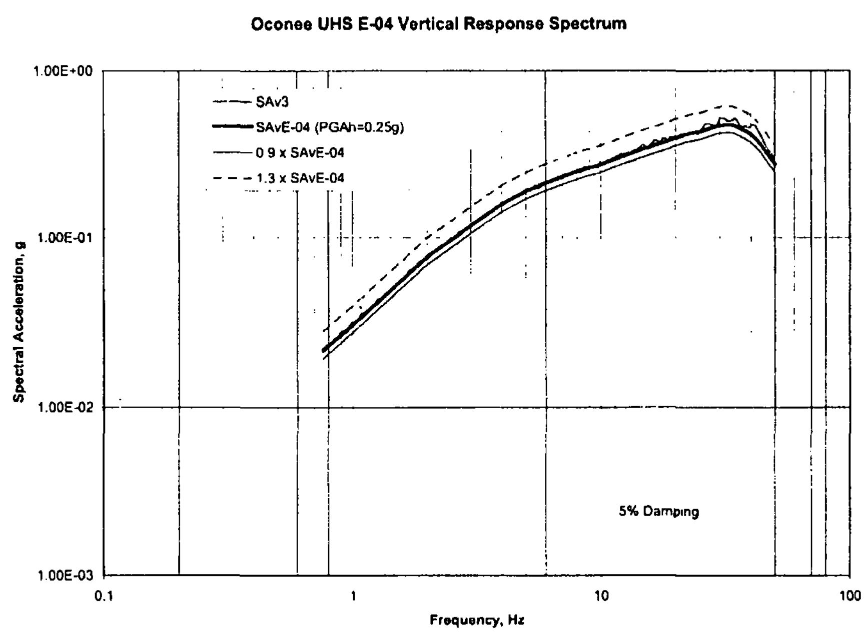


Figure B-6 Comparison of Spectra Generated from Revised UHS Time Histories with Criteria of Reference 3

The initial vertical time history component given in Reference B6 was also revised in Reference 4 to match the vertical rock UHS spectrum defined in Figure B-4 (it should be noted that the vertical spectrum scales with the 0.24 g PGA of the horizontal UHS). The spectrum computed from the revised vertical UHS time-history is also compared to the respective 0.9 and 1.3 bounds in Figure B-6.

As shown later, the primary portion of the dam response may be approximated as a Single-Degree-of-Freedom (SDOF) filter with a frequency of 1 Hz and an approximate level of 11% damping. Since the UHS given in Reference B2 are associated with 5% damping, the 11% damped response may be approximated using a scale factor which is the square root of the damping ratios. The variability of the approximate UHS spectrum shape associated with 11% damping (at approximately 1 Hz) is estimated as $\beta_U = 0.100$ and $\beta_R = 0.136$ associated with a unity scale factor, $F_{GS} = 1.0$.

References

B1. EQE International, "Guidance for Use of Existing PRA and Walkdown Evaluations from USI A-46 and IPEEE for Tier 1 Seismic Submittal, Oconee Nuclear Generating Station", EQE Report No. 59047.08, April 1996.

B2. "Probabilistic Seismic Hazard Evaluations at Nuclear Power Plant Sites in the Central and Eastern United States", EPRI NP-6395-D, April 1989.

B3. U. S. NRC, "Technical Basis of Regulatory Guidance on Design Ground Motions: Hazard- and Risk-Consistent Ground Motion Spectra Guidelines", NUREG/CR-6728, October 2001.

B4. "Determination of UHS Soil Surface Response", Revised Fragility Evaluation of Selected Equipment at the Oconee Nuclear Station, ABS Consulting Calculation 1272424-C-001, January, 2005.

B5. U. S. NRC, "Investigation of Techniques for the Development of Seismic Design Basis Using the Probabilistic Seismic Hazard Analysis", NUREG/CR-6606, April 1998.

B6. ONS Calculation No. OSC-5724, "Dynamic Reanalysis of the Auxiliary Buildings, Units 1-3, for IPEEE", Attachment W, Revision 1, February, 1998.

B7. American Society of Civil Engineers (ASCE), "Seismic Analysis of Safety-Related Nuclear Structures", ASCE Standard 4-98, 1998.

B8. American Society of Civil Engineers (ASCE), "Seismic Design Criteria for Structures, Systems, and Components in Nuclear Facilities", ASCE Standard 43-05, 2005.

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January 29, 2007

ATTACHMENT C
STRENGTH VALUES

Estimation of Material Shear Strength Values for Jocassee Dam

Jocassee Dam is a compacted rockfill dam with an impervious core. Four types of materials were used during construction: 1) Rockfill, 2) Random Rock, 3) Filters, and 4) Core. This document evaluates the available shear strength data quoted in various references and provides recommended lower-bound, median, and upper-bound material strength values for use in slope stability analyses of the dam. It will be assumed that material strengths are lognormal distributed and the upper and lower bounds are provided by the +/- one standard deviation strength values. Given a lognormal standard deviation, β, and median parameter value, $\langle m \rangle$, the upper bound value is given by, $m_{ub}=\langle m \rangle e^{\beta}$, and the lower bound value is given by, $m_{lb}=\langle m \rangle e^{-\beta}$. Provided that $\beta<0.4$, the coefficient of variation (COV) of the strength parameter may be used to approximate the lognormal standard deviation or $\beta \approx$COV.

Rockfill

According to References C1 and C2, Rockfill was a quarry-produced material described as a well-graded mixture of 70 percent or more hard rock larger than 6 inches with silty sandy gravel insufficient to fill voids. Reference C1 recommended a design value of $\phi=37°$ for the angle of internal friction based on a single shear test value (consolidated-undrained, R) of rockfill material. The drained and undrained design strengths were taken as equal. Reference C3 recommended $\phi=44°$ and Reference C4 used $\phi=45°$ for slope stability analyses. Based on review of Reference C5, it is judged that the $\phi=37°$ design value is a lower bound. The $\phi=44$-$45°$ values are judged to be extreme upper bounds associated with a near unity value of internal friction coefficient, tan ϕ. It is recommended that the rockfill material be considered as a fully draining material with equal undrained and drained shear strength characterized by $s_u=p \tan \phi$, where p is the normal pressure on the shear plane. Since the material is quarry produced and specified as well graded, the COV of the friction coefficient will be estimated as 0.1, thus $\beta \approx 0.1$. If $\phi_{lb}=37°$, then $\langle \tan \phi \rangle=[\tan \phi_{lb}]e^{\beta}$ and $\tan \phi_{ub}=\langle \tan \phi \rangle e^{\beta}$.

Table C-1
Recommended Rockfill Shear Strength Values

	Lower Bound		Median		Upper Bound	
Condition	**$\tan \phi_{lb}$**	**ϕ_{lb}**	**$\langle \tan \phi \rangle$**	**ϕ_m**	**$\tan \phi_{ub}$**	**ϕ_{ub}**
Undrained (R) & Drained (R'=S)	0.754	37°	0.833	39.8°	0.902	42.6°

Random Rock

Certain regions of the dam shell were constructed with a quarry produced material designated as random rock which was actually a compacted silty sand/large rock fragment mixture. There were two types of random rock mixtures produced and used in the designated shell regions:

> Random A: random mixture of gravelly silty sand with 30 to 50 percent relatively hard slightly decomposed rock larger than 6 inches.
>
> Random B: random mixture of gravelly silty sand with 50 to 70 percent relatively hard slightly decomposed rock larger than 6 inches.

Reference C1 reported, based on triaxial shear tests of compacted samples in the consolidated-undrained condition, that both materials were susceptible to strength reduction due to pore pressure buildup. The undrained strengths were characterized by a cohesion term and a friction term, s_u=c+p tan ϕ. The undrained strength envelope was defined by bi-linear segments with c_1 and c_2 being the ordinate intercepts and ϕ_1 and ϕ_2 being the angles of internal friction applicable in each region defined by the normal pressure at the break point p_{break}. In undrained shear, the Random A material was stronger than the Random B material; however, in drained shear Random B material was stronger than the Random A material. Reference C1 recommended separate design strengths for each material. However, there was no way to distinguish between the two materials in actual construction; thus, the materials were actually intermingled. Given that the two materials are placed at random within the designated shell regions, it appears reasonable to use the average of the envelope parameters of both materials as an estimate of the regional median properties. If a COV=0.15 ($\approx\beta$) is assumed, the lower- and upper-bound values approximate the design values recommended in Reference C1. Figure C-1 compares the strength envelopes. It should be noted that Reference C3 conservatively recommended use of the Random B properties as median and Reference C4 used ϕ=40.4° as the median internal friction angle for slope stability analyses.

Table C-2
Recommended Random Rock Shear Strength Values

Condition	Bound	c_1, ksf	tan ϕ_1	ϕ_1	p_{break}, ksf	c2, ksf	tan ϕ_2	ϕ_2
Undrained (R)	Lower	1.9	0.406	22.1°	17.5	4.1	0.282	15.7°
	Median	2.2	0.472	25.3°	17.5	4.8	0.327	18.1°
	Upper	2.6	0.548	28.7°	17.5	5.5	0.380	20.8°
Drained (R'=S)	Lower	0	0.644	32.8°				
	Median	0	0.748	36.8°				
	Upper	0	0.869	41.0°				

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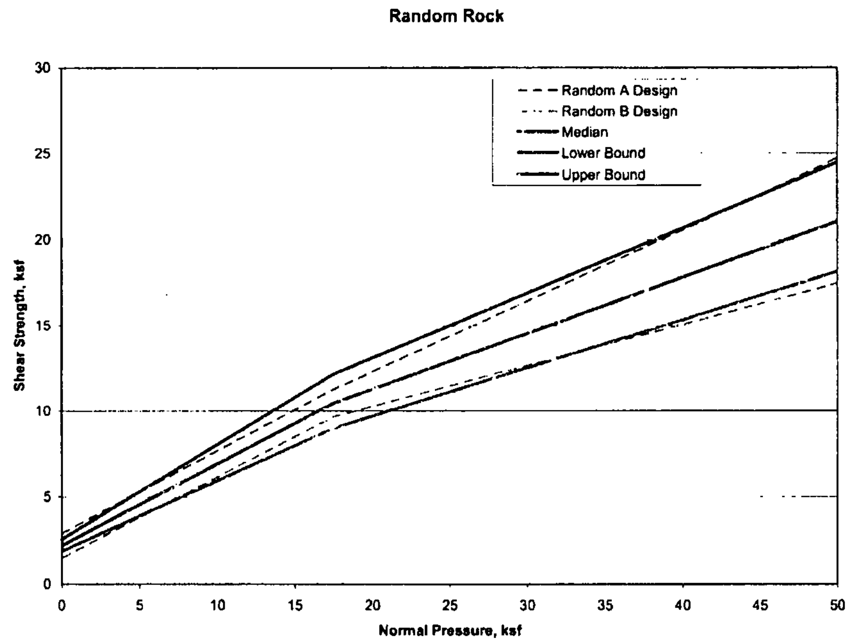

Figure C-1 Comparison of Undrained Shear Strength for Random Rock

Filters

According to References C1 and C2, the filters were a quarry produced material described as a specially graded mixture of pea gravel and course, clean sand. In agreement with Reference C3, the filter material will be considered as a fully draining material with equal undrained and drained shear strength and the median angle of internal friction of the filter material will be assumed as ϕ_m=35°. Since the material is quarry produced and specially washed and graded, the COV of the friction coefficient will be estimated as 0.1; thus, $\beta \approx 0.1$. If ϕ_m=35°, then $\tan \phi_{ub}=[\tan \phi_m]e^{\beta}$ and $\tan \phi_{lb}=[\tan \phi_m]e^{-\beta}$.

Table C-3
Recommended Filter Shear Strength Values

	Lower Bound		Median		Upper Bound	
Condition	**tan ϕ_{lb}**	**ϕ_{lb}**	**tan ϕ_m**	**ϕ_m**	**tan ϕ_{ub}**	**ϕ_{ub}**
Undrained (R) & Drained (R'=S)	0.634	32.4°	0.700	35.0°	0.774	37.7°

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Core

References C1 and C2 indicate that two types of materials were used for core construction: 1) clayey silt and 2) silty sand. They were obtained from local borrow pits. Reference C2 indicates that compacted clayey silt material was used in the core center region with compacted silty sand used as a transition zone to the location of the filters. Reference C1 reported design values for each material that do not seem to reflect the triaxial shear test values reported for the respective materials. Reference C3 provided estimates of core shear strength that differ significantly from both the recommended design values and data presented in Reference C1. The data of Reference C1 on compacted borrow pit samples was re-evaluated and separated into two groups representing clayey silt materials and silty sand materials. New average shear strength values were computed for each material group. The undrained strengths are characterized by a cohesion term and a friction term, s_u=c+p tan ϕ. The undrained strength envelope is defined by bi-linear segments with c_1 and c_2 being the ordinate intercepts and ϕ_1 and ϕ_2 being the angles of internal friction applicable in each region defined by the normal pressure at the break point p_{break}. If the overall average of the two materials are used as an estimate of core material strength and a COV=0.15 ($\approx\beta$) is assumed, the lower- and upper-bound values encompass the revised average test values for each material developed from the data reported in Reference C1. Figure C-2 compares the core material strength envelopes. The median values given in Table C-4 represent a judgment of the average valves of expected core shear strength and represent the uncertainty of both material strength and spatial placement.

Table C-4
Recommended Core Shear Strength Values

Condition	Bound	c_1, ksf	tan ϕ_1	ϕ_1	p_{break}, ksf	c2, ksf	tan ϕ_2	ϕ_2
Undrained (R)	Lower	0.8	0.551	28.9°	20.4	5.0	0.345	19.0°
	Median	0.9	0.641	32.6°	20.4	5.8	0.400	21.8°
	Upper	1.0	0.744	36.7°	20.4	6.7	0.465	25.0°
Drained (R'=S)	Lower	0	0.511	27.0°				
	Median	0	0.593	30.7°				
	Upper	0	0.689	34.6°				

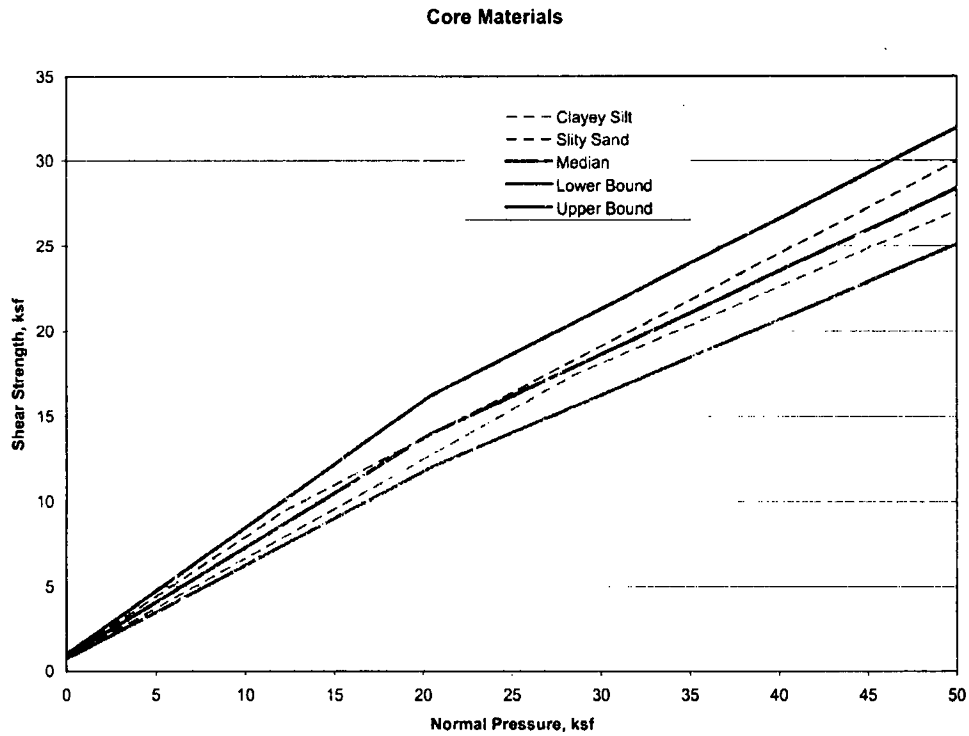

Figure C-2 Comparison of Undrained Shear Strength for Core Materials

References

C1. Law Engineering Testing Company, "Jocassee Development Report, Keowee-Toxaway Project", prepared for Duke Power Company, November, 1966.

C2. Duke Power Company, "Specifications, General Grading Work", Keowee-Toxaway Project, Specification No. KS-1, August, 1969.

C3. Devine Tarbell & Associates, "Supporting Technical Information, Jocassee Pumped Storage Project, FERC # 2503-SC", prepared for Duke Power, December, 2004 (Rev. 0).

C4. Veneziano, D., "Seismic Fragility Curves for Jocassee Dam and Oconee Dikes", prepared for Law Engineering Testing Company, June, 1981.

C5. Leps, T. M., "Review of Shearing Strength of Rockfill", Journal of the Soil Mechanics and Foundation Division, ASCE, Volume 96, No. SM4, July 1970.

C6. Jones, A. L., Kramer, S. L., and Arduino, P., "Estimation of Uncertainty In Geotechnical Properties for Performance-Based Earthquake Engineering", PEER Report 2002/16, Pacific Earthquake Engineering Research Center, College of Engineering, University of California, Berkeley, December, 2002.

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ATTACHMENT D
MATERIAL VALUES

Estimation of Material Property Values for Jocassee Dam

Jocassee Dam was constructed used three basic materials which are designated as: rockfill, random rock, and core materials. The dam foundation is an approximate 40 ft. layer of weathered rock underlain by sound hard bedrock. Based on review of the technical literature, ONS FSAR, test data contained in the original design report, and the available construction documentation, the density and range of strength and physical properties were established for each material. Upper-, median, and lower-strength bounds (approximate one sigma) for the shear strength, maximum value of shear modulus, shear modulus degradation as a function of shear strain, and material damping as a function of shear strain, were established.

Jocassee Dam was designed with a downsteam core filter that acts as a "chimney" drain as well a long tailwater drain to the level of Lake Keowee. Due to this drain configuration, it is judged that the phreatic surface follows the drains and thus the variability of the extent of saturated materials does not need to be considered.

Density

Dam material densities were obtained from Reference D3. Based on prior studies, the variability in compacted soil density is small and has only on minor effect on fragility values compared to other properties; thus, the following density values are considered as median estimates with negligible variability:

Dam Material	Dry	Above Water (Moist)	Below water (Saturated)
Rockfill	126.5 pcf	129 pcf	141 pcf
Random Rock	126.5 pcf	130 pcf	141.5 pcf
Core	101 pcf	112 pcf	125 pcf

Foundation Rock densities were obtained from Reference D4 based on review of ONS FSAR values. The median and one sigma density values for rock are:

Foundation Material	Low	Median	High
Weathered Rock	144.6 pcf	152.2 pcf	159.9 pcf
Hard Rock	162.8 pcf	170.2 pcf	177.5 pcf

Shear Modulus

The small strain (10^{-4}%) shear modulus values for the dam materials were estimated using the relation, $G_{max} = 1000\ K_{2,max}\ (\sigma_m')^{1/2}$, where σ_m' is the mean principal effective stress and $K_{2,max}$ is a constant associated with sands and gravel. The units of G_{max} and σ_m' are psf. σ_m' is estimated with the relation, $\sigma_m' = [(1+2K_0)/2]\ \sigma_v'$, where σ_v' is the vertical effective overburden pressure.

Void ratios and specific gravity values were calculated using the dry and saturated densities and then utilized to estimate the buoyant material density for the saturated materials. The vertical effective overburden pressures (at the centroid of each finite element) were determined by considering the dam as a series of stepped soil columns using the dry and buoyant densities. The range of $K_{2,max}$ values for rockfill were estimated from data given in Reference D9. The range of $K_{2,max}$ values for the core (silty-sand) and filters were estimated from data given in Reference D7 for sands. The range of $K_{2,max}$ values for random rock were chosen to be between the core and rockfill materials. The median and one sigma values for $K_{2,max}$ are:

Dam Material	Low	Median	High
Rockfill	150	165	180
Random Rock	110	130	150
Core and Filters	70	90	110

In the QUAD4M model, the weathered rock is represented by an extended layer of elements at the dam base with constant shear modulus. The weathered rock shear modulus values were obtained from Reference D4. The median and one sigma values for G_{max} for weathered rock are:

Foundation Material	Low	Median	High
Weathered Rock	42.6×10^6 psf	54.1×10^6 psf	70.4×10^6 psf

Poisson's ratio was taken as 0.32 for soil materials and 0.15 for weathered rock.

The compliant transmitting base option of QUAD4M was used to simulate the bedrock half-space. The median and one sigma values for the p-wave and s-wave velocities of the bedrock were obtained from Reference D4 as:

Bedrock	Low	Median	High
Shear Wave Velocity	5718 fps	6537 fps	7365 fps
Primary Wave Velocity	9544 fps	10,667 fps	11,790 fps

Shear Modulus Reduction

The reduction in shear modulus for soil materials as a function of shear strain was estimated based on the recommendations of Reference D8. The median and one sigma functions for each soil material are presented in Figures D-1 through D-3.

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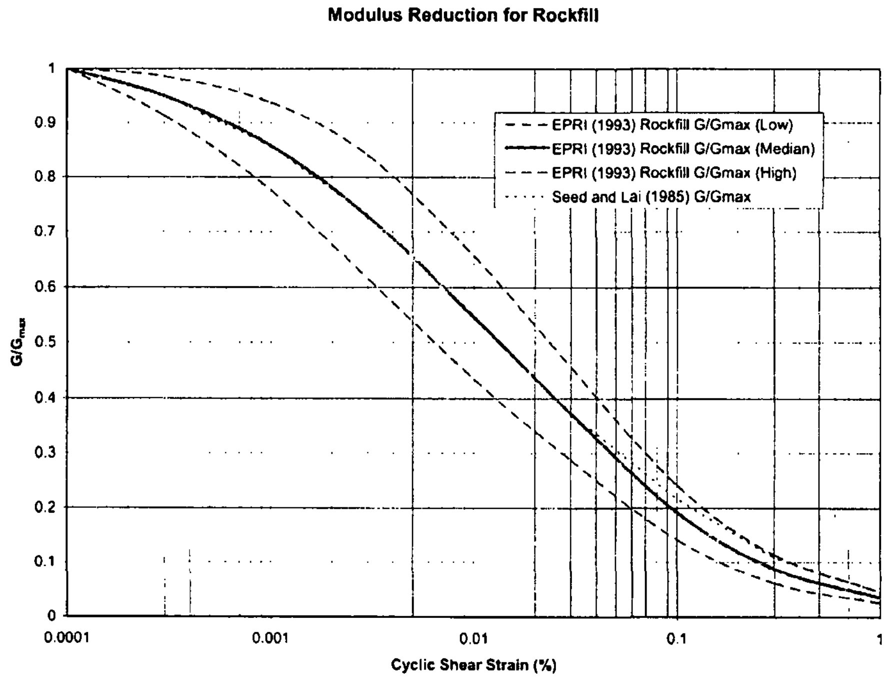

Figure D-1 Shear Modulus Reduction for Rockfill

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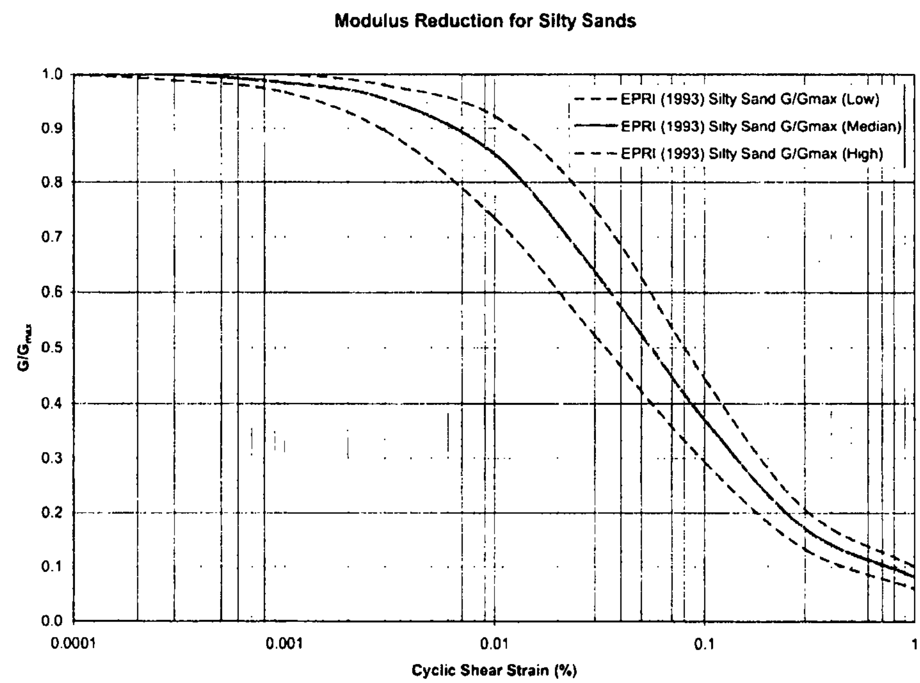

Figure D-2 Shear Modulus Reduction for Silty-Sands (Core Material)

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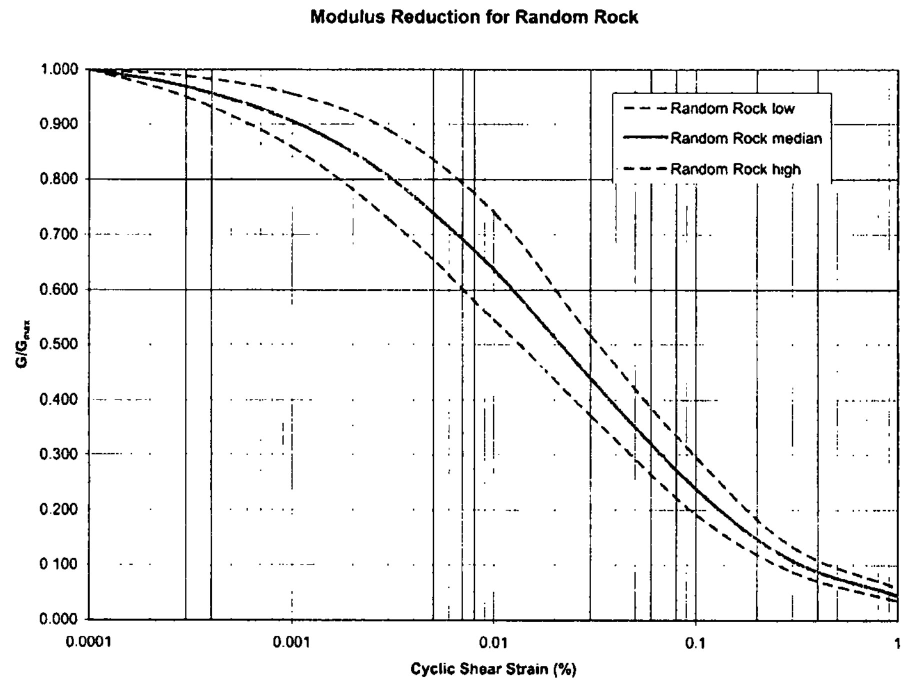

Figure D-3 Shear Modulus Reduction for Random Rock (Sand and Rock)

Damping Ratios

The damping ratios for dam materials as a function of shear strain were estimated based on the recommendations of Reference D9. The median and one sigma functions for rockfill, random rock, and core materials are presented in Figure D-4.

The damping ratio for the weathered rock layer was taken as a constant 2%.

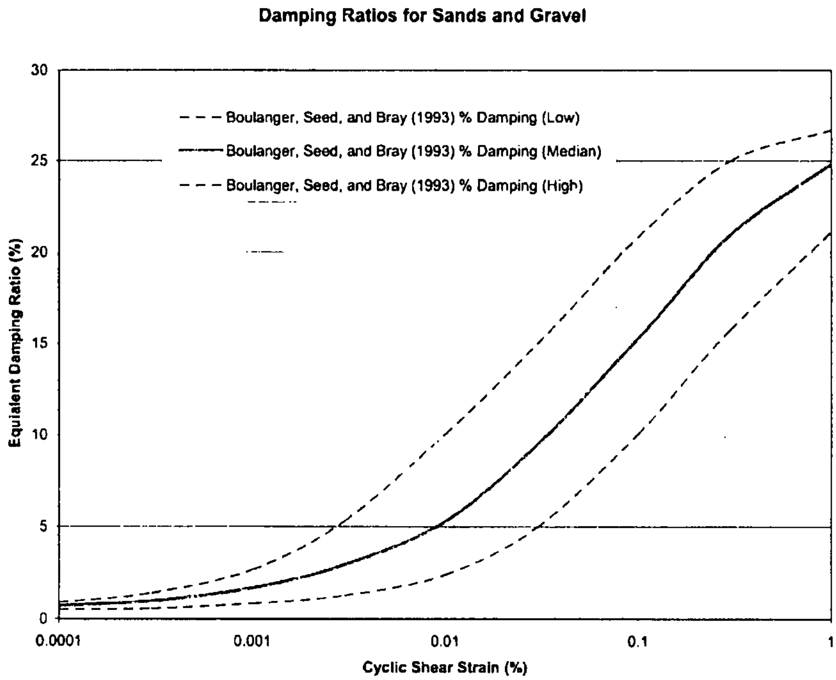

Figure D-4 Damping Ratios for Dam Soil Materials (Sand and Rockfill)

References

D1. Law Engineering Testing Company, "Jocassee Development Report, Keowee-Toxaway Project", prepared for Duke Power Company, November, 1966.

D2. Duke Power Company, "Specifications, General Grading Work", Keowee-Toxaway Project, Specification No. KS-1, August, 1969.

D3. Devine Tarbell & Associates, "Supporting Technical Information, Jocassee Pumped Storage Project, FERC # 2503-SC", prepared for Duke Power, December, 2004 (Rev. 0).

D4. ABS Consulting, "Determination of Oconee Soil Profiles", Calculation No. 1272424-C-002, Rev. 0, January, 2005.

D5. "Geology, Seismology, and Geotechnical Engineering", UFSAR Section 2.5, Oconee Nuclear Station, 2000.

D6. Sowers, G.B.and Sowers, G.F., *Introductory Soil Mechanics and Foundations*, The Macmillan Company, New York, 1965.

D7. Kramer, S. L., *Geotechnical Earthquake Engineering*, Prentice-Hall, New Jersey, 1996.

D8."Guidelines for Determining Design Basis Ground Motions", EPRI TR-102293, November 1993.

D9.Boulanger, R.W., Seed, R.B. and Bray, J.D., "Investigation of the Response of Cogswell Dam in the Whittier Narrows Earthquake of October 1, 1987", California Strong Motion Instrumentation Program, Data Utilization Report CSMIP/93-03, December 1993.

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ATTACHMENT E
IDENTIFICATION OF FAILURE SURFACES

The primary failure modes of embankment dams are associated with the deformation of unstable slopes. The analysis of slope stability was accomplished using the software package UTEXAS4 (Reference E1).

The first step was to locate failure surfaces which may result in a loss of reservoir should a segment of the embankment fail under dead weight loading. Using Spencer's method and the median soil properties, numerous failure surfaces were located and analyzed using the search capability of the program. In general, the critical failure surfaces (lowest factor of safety) were very shallow and located away from the crest which would not result in a loss of reservoir. Upstream and downstream slip surfaces were selected which exit the analysis section near the toe, approximately mid-height, and approximately one-third of the structure's height below the crest as shown in Figure E-1. In Table E-1, the slip surfaces are denoted as deep, median, and shallow corresponding to the point of exit. These selected surfaces represent lower factors of safety for slope failures which may result in loss of reservoir. For example, the third surface listed in Table E-1 has the lowest factors of safety as well as the lowest yield acceleration. However, reference to Figure E-1 will indicate that the slip surface does not pass through the crest, thus failure of this soil mass cannot cause loss of reservoir. The resulting dead weight factors of safety are all equal to or greater than 1.5 which is a common design acceptance criterion. As a check, the factors of safety were also computed using Bishop's method and found to compare well with those obtained using Spencer's method.

The second step of the analysis was to estimate the horizontal (UTEXAS4 default option) yield acceleration (applied as a pseudo-static load) for the failure mass encompassed by each failure surface. This was accomplished using the SEISMIC command of UTEXAS4 (Bishop's method is default seismic analysis method) and increasing the acceleration until the resulting factor of safety was approximately unity. The resulting yield accelerations for each sliding mass are given in Table E-1.

Based on these results, the four sliding masses (Ds1, Ds2, Us1, and Us2) shown in Figure E-2 were selected for further evaluation. Each siding mass has the potential of lowering the crest resulting in overtopping of the dam. Then using the failure surface of each mass, the analyses were repeated using one sigma material properties. Since masses Ds1 and Ds2 have similar locations within the dam, and thus are expected to have similar variability, an alternate downstream deep category mass (Ds3, FS=1.839) was chosen in order to compare to the upstream deep mass. Table E-2 provides a summary of the dead weight factors of safety and the pseudo-static yield acceleration upper, median, and lower values.

If the yield acceleration values are viewed as the capacity, or the response level of the mass C.G. for which sliding is just initiated, then the variability of the yield acceleration may be estimated by considering assuming the applicability of a lognormal distribution and the range between upper and lower yield accelerations as two sigma with the relation, $\beta = 1/2 \ln(\text{upper}/\text{lower})$. The applicability of this assumption may be checked by computing a median value using the relation

⟨median⟩ = (upper) $e^{-\beta}$, and then checking the computed median value with the Table E-2 median.

The variability of the yield acceleration and estimated median values are given in the following:

Sliding Mass	Logarithmic S.D., β	⟨Median⟩
Ds1	0.357	0.205g
Ds3	0.156	0.279g
Us1	0.256	0.119g
Us2	0.235	0.133g

Since the estimated median values are slightly lower than those given in Table E-2, these lower values will be used in subsequent calculations of Newmark sliding deformation requiring an initial threshold acceleration at which slip begins. Thus, the sliding displacements obtained based on these reduced values of yield acceleration will be slightly conservative.

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Table E-1
Results of Slope Stability Analysis

Factor of Safety		Center Coordinates		Radius	Yield Acceleration		Description		
Spencer's	Bishop	X	Y	(ft.)	g	Factor of Safety	Upstream	Downstream	Category
1.582	1.576	525.0	2485.0	470	0.213	1.000		X	Shallow
1.600	1.595	210.0	2860.0	980	0.216	1.000		X	Median
1.492	1.490	270.0	2684.0	775	0.187	1.000		X	Median
1.651	1.645	360.0	2725.0	800	0.225	1.001		X	Median
1.835	1.839	150.0	2470.0	750	0.282	1.000		X	Deep
1.579	1.576	-77.0	3165.0	1375	0.210	1.001		X	Deep
1.666	1.661	1090.0	2280.0	300	0.148	1.001	X		Shallow
1.565	1.560	1390.0	2670.0	800	0.123	1.000	X		Median
1.644	1.638	1490.0	2760.0	950	0.136	1.002	X		Deep
1.737	1.734	1510.0	2580.0	840.35	0.160	1.001	X		Deep

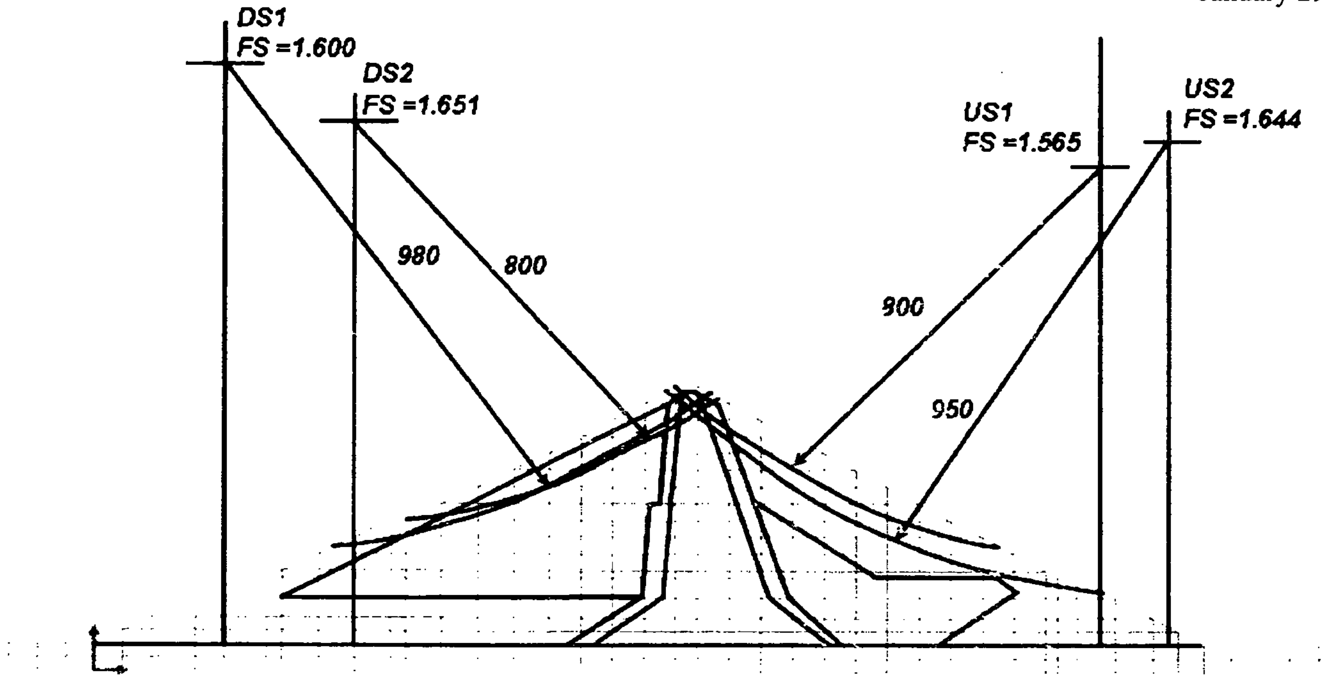

Figure E-2 Identification of Sliding Masses Selected for Study

Table E-2
Yield Accelerations for Parametric Shear Strength Parameters

	Coordinates			Static Factor of Safety						Yield Acceleration		
				Lower*		Median*		Upper*		Lower*	Median*	Upper*
Slope	X	Y	Radius	S+	B+	S+	B+	S+	B+			
Downstream 1	210.0	2860.0	980.0	1.388	1.383	1.600	1.595	1.845	1.841	0.144	0.216	0.294
Downstream 3	150.0	2470.0	750.0	1.695	1.687	1.835	1.839	1.994	2.012	0.239	0.282	0.327
Upstream 1	1390.0	2670.0	800.0	1.413	1.408	1.565	1.560	1.731	1.726	0.092	0.123	0.154
Upstream 2	1490.0	2760.0	950.0	1.484	1.478	1.644	1.638	1.818	1.812	0.105	0.136	0.168

* Denotes shear strength envelope used in analysis.
\+ S = Spencer's Method
B = Bishop's Method

References

E1. Wright, S. G., "UTEXAS4 – A Computer Program for Slope Stability Calculations", Shinoak Software, Austin, Texas, 1999.

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ATTACHMENT F
DEVELOPMENT OF QUAD4M MODEL FOR JOCASSEE DAM

The response analysis of Jocassee Dam was accomplished using the software package QUAD4M (Reference F1). QUAD4M is a modified version of the original program QUAD4 (Reference F2) which incorporates significant improvements including: 1) the option of using a compliant base (transmitting boundary) that allows the rock foundation to be treated as a flexible half-space; 2) a new specification of Rayleigh damping; 3) an improved time-stepping algorithm which does not add additional numerical damping; and 4) an option of computing the average seismic coefficient for a specified potential sliding mass. The program is freely distributed and used by geotechnical consultants worldwide.

The program is a procedure for dynamic analysis of two-dimensional finite-element representation that uses equivalent linear strain-dependent modulus and damping properties for each element. It is similar in concept to the well known one-dimensional program SHAKE; however, it is a time-step analysis that uses Rayleigh damping and allows variable damping for different elements. The program uses an iterative process to estimate nonlinear strain-dependent properties. Initially, shear moduli and damping ratios are estimated for each element, and the system is analyzed using these initial properties. After each iteration, values of the effective shear strain are computed for each element, and the corresponding modulus and damping, at the computed strain level, are compared with those estimated from the previous iteration. The analysis procedure is repeated until convergence is achieved. Unlike SHAKE, which does the iterative computations in the frequency domain, QUAD4M does all computations in the time domain.

Prior to the project, the ability of the Rayleigh damping algorithm, incorporated within QUAD4M to specify the element damping matrices, to accommodate the difference between the dam fundamental frequency (1-1.5 Hz) and the predominant frequency of the UHS input motion (20-25 Hz) was unknown. The basic Rayleigh damping algorithm sets the modal damping ratio equal at two selected frequencies. This procedure insures that all apparent modes between the two set values of frequency will have damping ratios less that the selected modal damping ratio. Normal applications of the algorithm do not span two decades of frequency. However, after several initial QUAD4M runs were made with material damping ratio set equal at the dam fundamental frequency and 22.5 Hz, it was apparent that the algorithm was functioning properly; thus, code modification of the damping specification was not necessary.

The finite element mesh used for the dynamic analysis of Jocassee Dam is shown in Figure F-1. The model consists of 385 elements with 413 nodes. The profile shown in Figure F-1 is for the maximum base dimension of the dam which occurs over an approximate 200 ft length in the center portion of the dam. Normal practice is to evaluate a dam using a two-dimensional slice. There are three-dimensional boundary effects that tend to raise the fundamental frequency of the dam and thus increase the response. These lateral boundaries, however, also provide additional load paths. It is judged that fragility estimates based on two-dimensional response are conservative. Figure F-2 shows the dam zones with different materials overlaid on the finite-

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element mesh. Figure F-3 shows the assignment of material to each element used to approximate the dam zones.

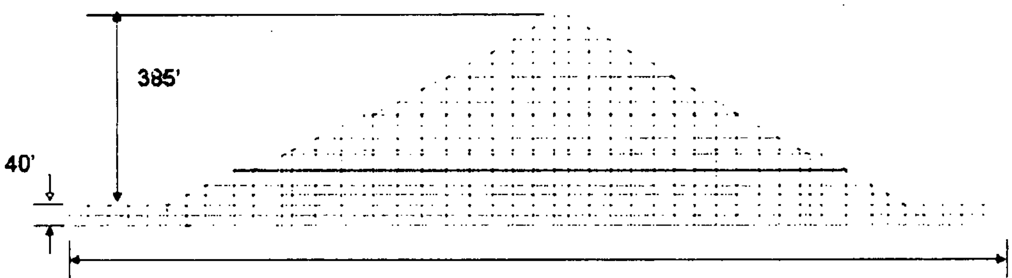

Figure F-1 QUAD4M Dam Model

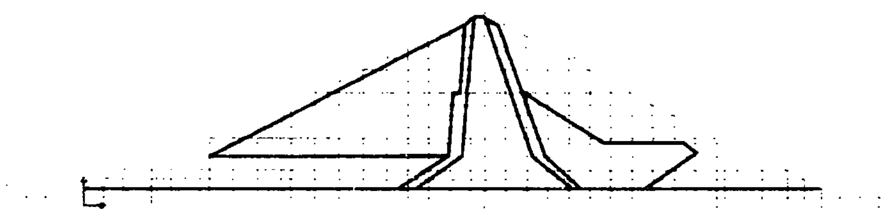

Figure F-2 QUAD4M Element Grid with Dam Zone Identification

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As noted above, QUAD4M allows for a compliant base and treats the bedrock as an elastic half-space. In order to simulate the weathered rock layer, the finite element mesh was extended in the upstream and downstream directions and the lateral boundaries were fixed in the vertical direction but free to move in the horizontal direction (i.e., horizontal rollers).

QUAD4M also allows the seismic coefficients (as a time history) of a potential sliding mass to be determined. These seismic coefficients represent the average acceleration at the mass C.G. which can be used in Newmark sliding calculations. Figures F-4, F-5, F-6, and F-7 show the selection of elements used to approximate the sliding masses Ds1, Ds2, Us1, and Us2, respectively.

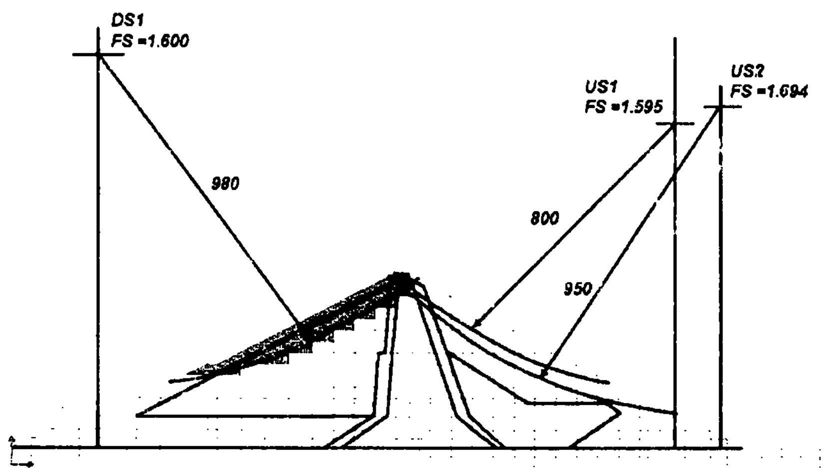

Figure F-4 Selection of QUAD4M Elements Representing Downstream Sliding Mass Ds1

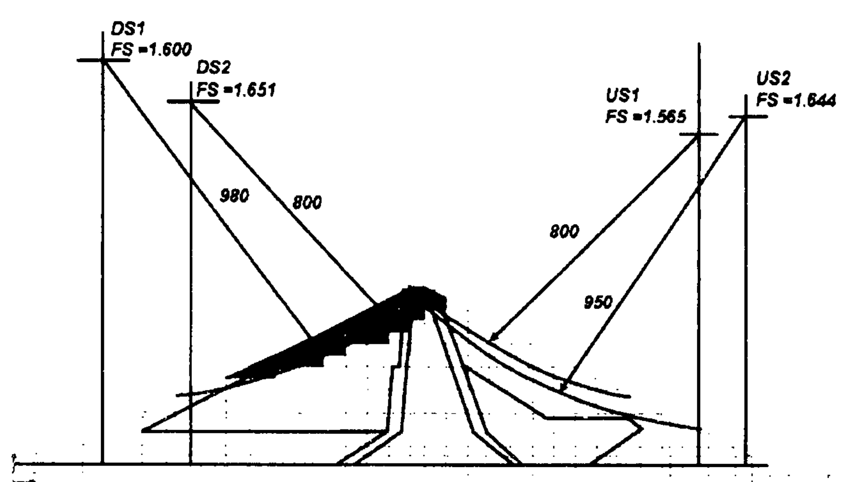

Figure F-5 Selection of QUAD4M Elements Representing Downstream Sliding Mass Ds2

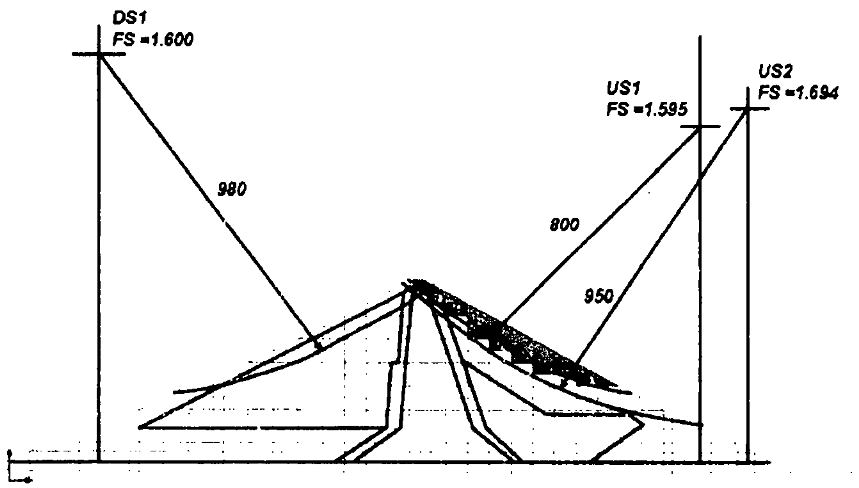

Figure F-6 Selection of QUAD4M Elements Representing Upstream Sliding Mass Us1

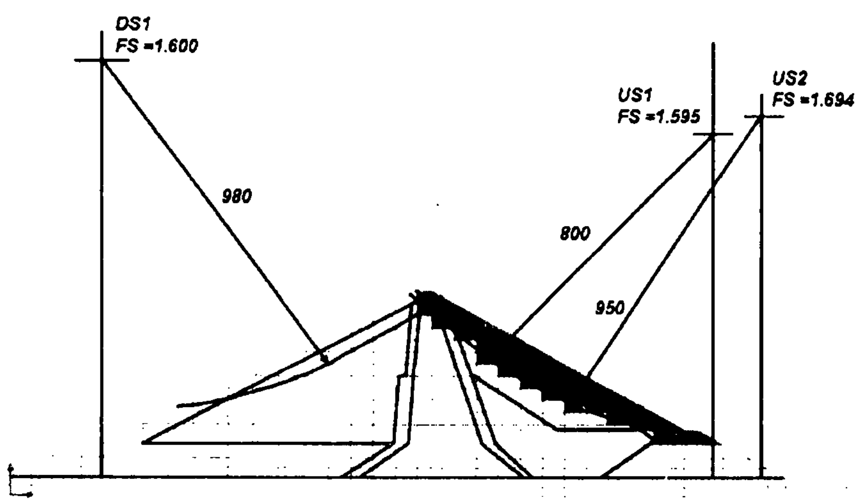

Figure F-7 Selection of QUAD4M Elements Representing Upstream Sliding Mass Us2

The response of the dam was computed using the UHS bedrock surface outcropping motions which were developed in Reference F3. The horizontal input time-history, scaled to 0.24 g as a

reference value, is shown in Figure F-8. The comparison of the target horizontal UHS spectrum (5% damping) and the response spectrum of the time-history is shown in Figure F-9. The vertical input time-history, which is scaled with the horizontal component, is shown in Figure F-10. The comparison of the target vertical UHS spectrum (5% damping) and the response spectrum of the time-history is shown in Figure F-11. In general, the extreme peak of each time history serves to anchor the spectrum to the desired PGA value. The peak can be clipped to a lower value without affecting the frequency content of the motion below approximately 30 Hz.

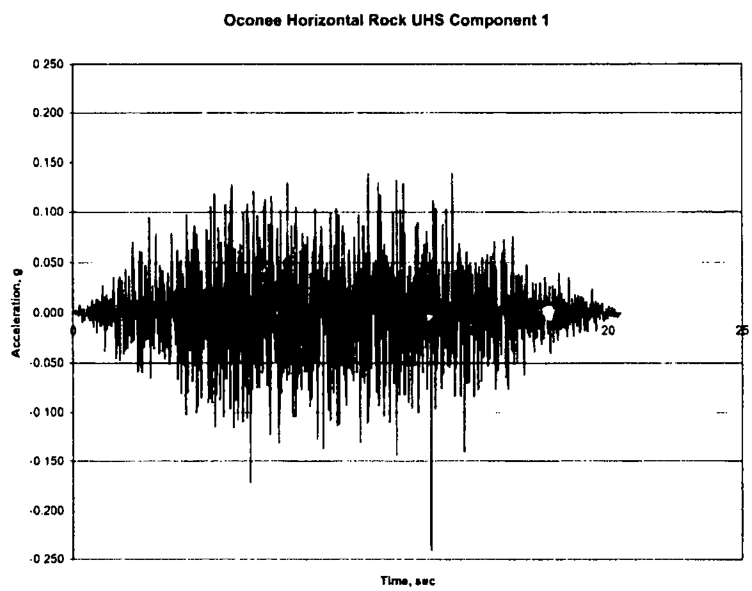

Figure F-8 UHS Horizontal Time History

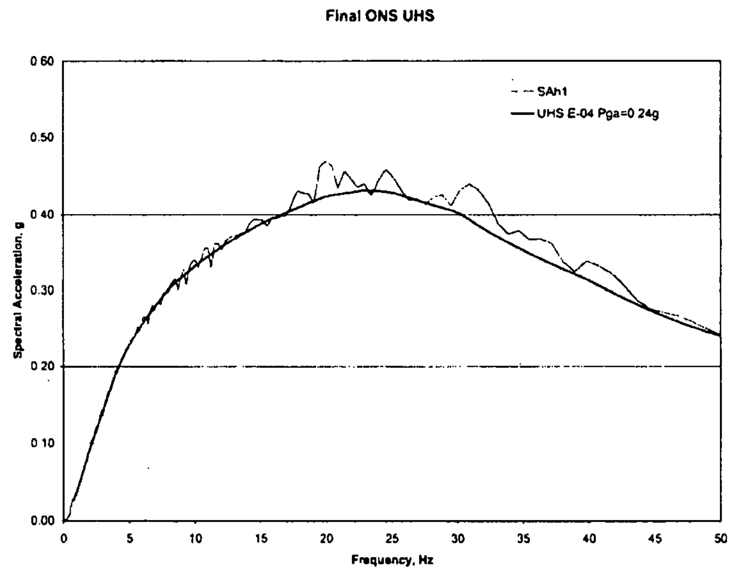

Figure F-9. Comparison of Horizontal Time-History Response Spectrum with Target Spectrum (5% Damping

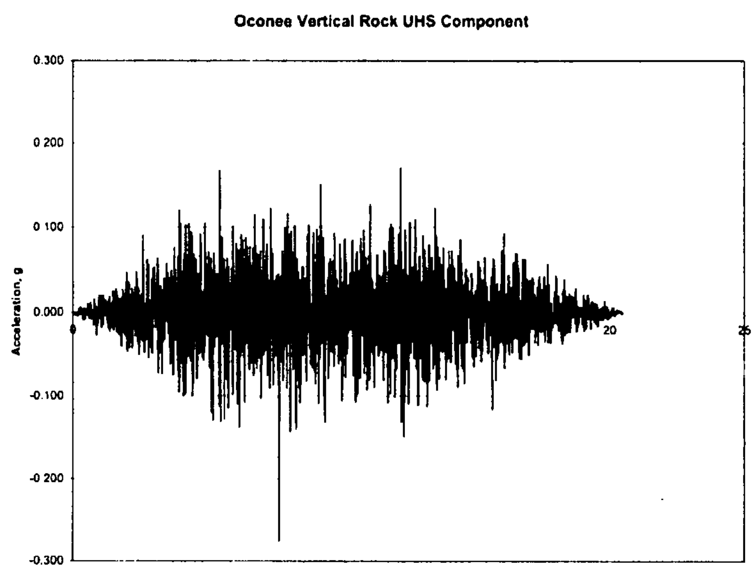

Figure F-10. UHS Vertical Time History

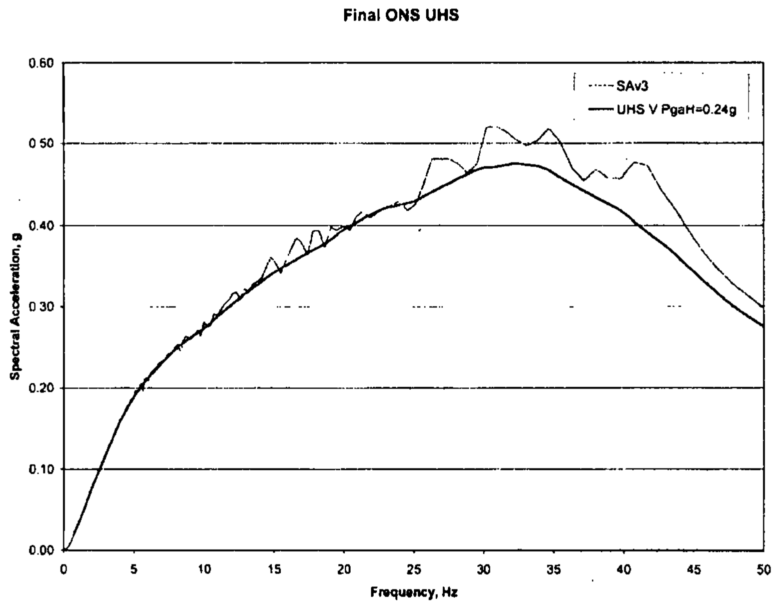

Figure F-11. Comparison of Vertical Time-History Response Spectrum with Target Spectrum (5% Damping

It is common design practice for dams to only consider horizontal input motion. QUAD4M, however, allows both horizontal and vertical input motion. For the input scaling, both horizontal and vertical input motions where used.

Consider the case of median dam material properties (G_{max}, G/G_{max}, equivalent damping). The input motions are then scaled until the peak horizontal seismic coefficient of the selected sliding mass output by QUAD4M is just equal to the yield acceleration of the mass segment. Figure F-12 shows the seismic coefficient computed for downstream mass Ds1 using a scale factor of three. As can be noted, the yield acceleration of 0.216 g is just slightly exceeded. (The reversed motion is also considered since it can be caused by switching the polarity of the input motion.) Figure F-13 shows the seismic coefficient computed for upstream mass Us1 using a scale factor of three. As can be noted. the there is some higher frequency content in the Us1 seismic coefficient. While the yield acceleration of 0.123 g is exceeded, the duration of the pulses above that level are not sufficient to sustain a increasing slip motion. The accumulative slip is less than 3/16 inch which is considered as negligible amount. Thus, the initiation of slip for both the Ds1 and Us1 masses occurs at the same scaled input level.

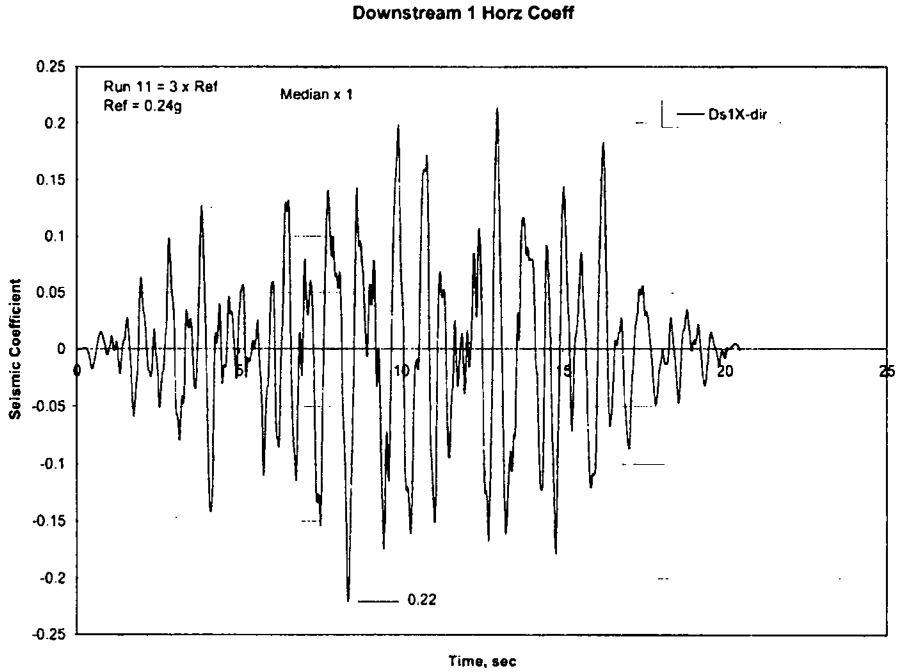

Figure F-12 Response of Ds1 Mass for Input Scaling of Three

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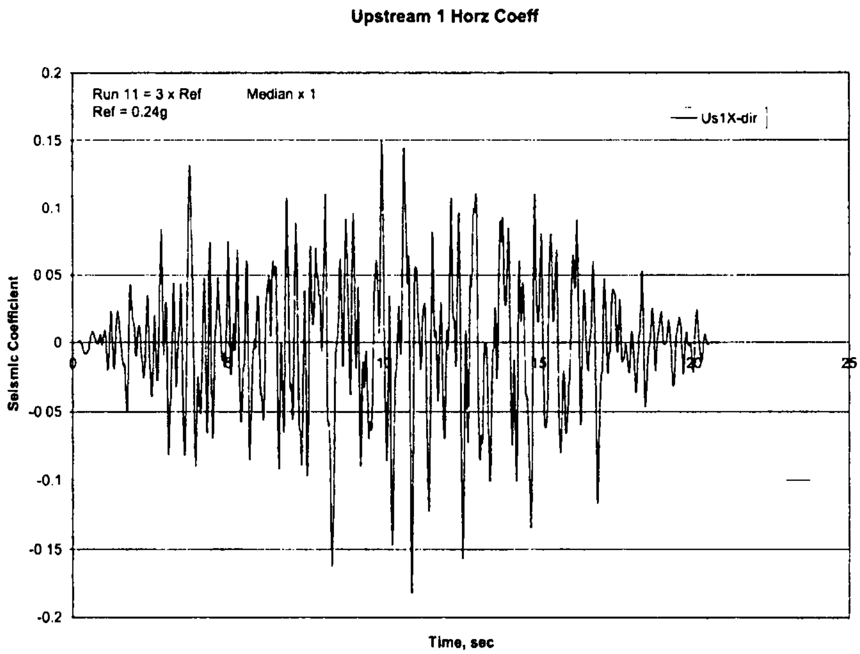

Figure F-13 Response of Us1 Mass for Input Scaling of Three

The above cases represents the median scale factor, ⟨SF⟩=3 (PGA=3x0.24=0.72g), for both the Ds1 and Us1 slope masses. The variability in the scaling may be determined using the approximate second moment procedure (Reference F4) which considers the input scale factor necessary to achieve the yield level given a one sigma variance of each material property. Given the scaling results for a +1 sigma variance in a selected material property is SF[+] and the scaling results for a -1 sigma variance in the same material property is SF[-], then the total variability in scale factor for the i^{th} material property is $\beta_i = 1/2\ln(SF[+]/SF[-])$ and the total variability is $\beta_T = \{\Sigma(\beta_i)^2\}^{1/2}$.

The following is a summary of the QUAD4M input scaling results for potential sliding masses Ds1 and Us1:

Material Property	SF[+]	SF[-]	β_i
G_{max}	3.6	2.55	0.172
Damping	3.6	2.6	0.163
G/G_{max}	3.4	2.79	0.099
		β_T	0.257

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QUAD4M estimates the fundamental frequency and composite overall system damping of the dam at each iteration. Figure F-14 plots the final fundamental frequency of the dam as a function of overall input scale factor, F. Figure F-15 plots the effective overall damping of the dam as a function of overall input scale factor, F.

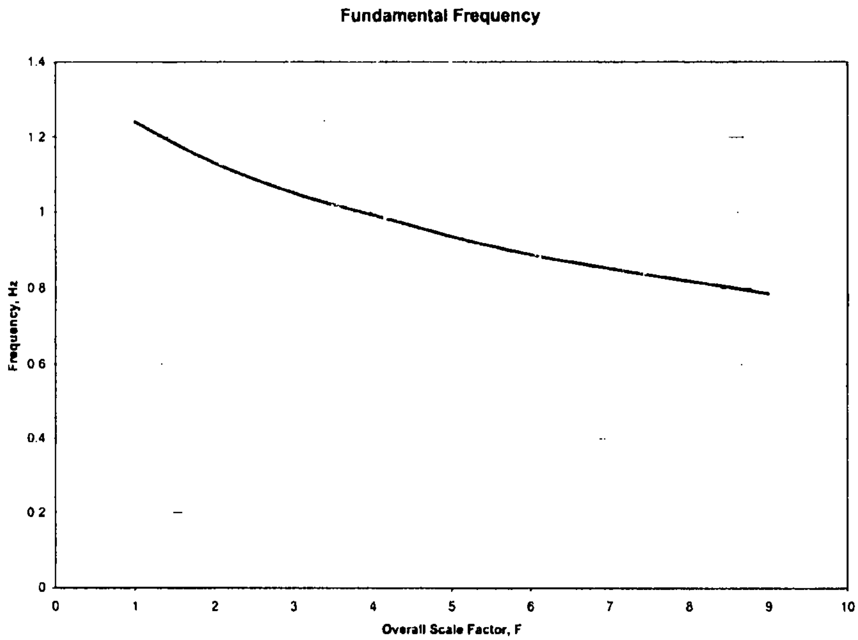

Figure F-14. Fundamental Frequency of Dam as a Function of Input Scale Factor

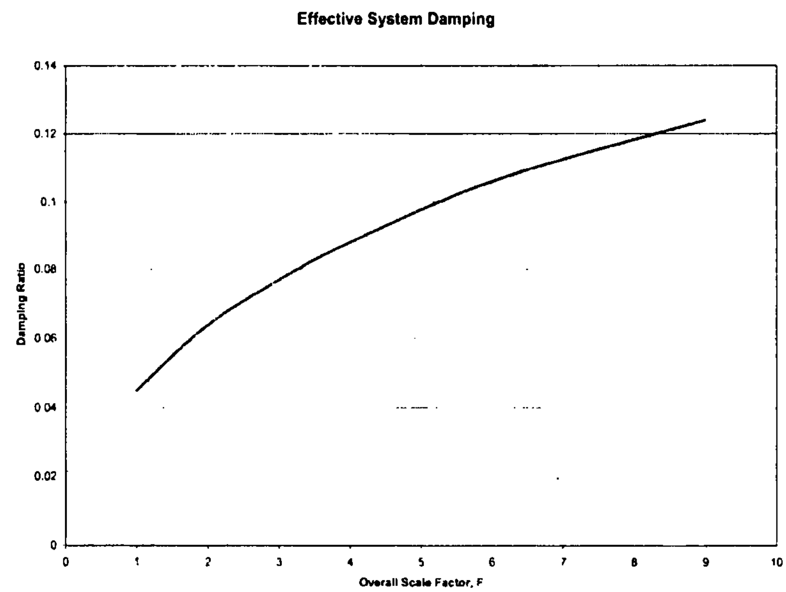

Figure F-14. Effective Damping of Dam as a Function of Input Scale Factor

References

F1. Hudson, M., et al., "User's Manual for QUAD4M - A Computer Program to Evaluate the Seismic Response of Soil Structures Using Finite Element Procedures and Incorporating a Compliant Base", Center for Geotechnical Modeling, Department of Civil & Environmental Engineering, University of California, Davis, Revised 2003.

F2. Idriss, I.M., et al., "QUAD4 - A Computer Program for Evaluating the Seismic Response of Soil Structures by Variable Damping Finite Element Procedures", EERC 73-16, College of Engineering, University of California, Berkeley, July, 1973.

F3. "Determination of UHS Soil Surface Response", Revised Fragility Evaluation of Selected Equipment at the Oconee Nuclear Station, ABS Consulting Calculation 1272424-C-001, January, 2005.

F4. "Methodology for Developing Seismic Fragilities," EPRI Report TR-103959, June 1994.

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ATTACHMENT G
DETERMINATION OF SLIDING DEFORMATIONS

Once the demand level, or scaling factor, associated with the initiation of sliding has been established, the input motion can be scaled beyond this level with the resulting sliding displacement of the slope mass. If the sliding mass is assumed to not appreciably change the response of the dam, then the portion of the seismic coefficient greater than the yield acceleration level (clipped portion) can be double integrated to obtain the sliding displacement of the slope mass. This is the classic Newmark analogy (Reference G1) of a block sliding down a plane with stick-slip motion. In normal practice, the slope displacements are estimated by considering only the horizontal response motion. To be correct, the motion of the mass down the slope should be determined and then split into vertical and horizontal components. The motion down the slope is on the order of 30% larger than that determined by the integration of the clipped horizontal motion, so the consideration of only the horizontal dam response is a reasonable first order approximation.

Figure G-1 shows the horizontal (X-direction) seismic coefficient history of the Ds1 mass obtained from QUAD4M when the median case is scaled by an additional scale factor (SF_δ) of three beyond the initiation of yield, or an UHS input motion scaled to a PGA of 3x3x0.24 = 2.16 g. The reduced yield level of 0.205 g is indicated for both the forward and reversed motion.

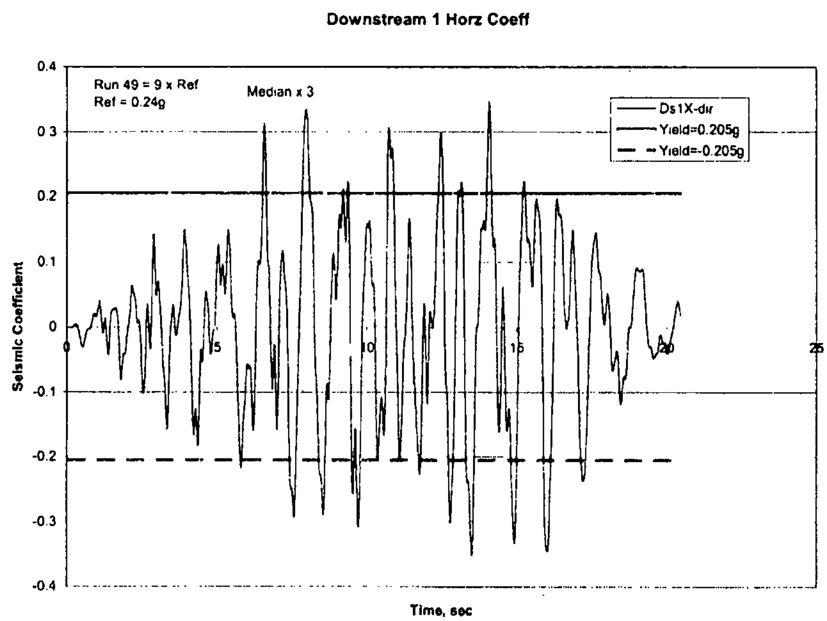

Figure G-1 Response of Ds1 Mass for Additional Scaling of Three beyond Median Yield Level

Figure G-2 shows the horizontal (X-direction) seismic coefficient history of the Us1 mass obtained from QUAD4M when the median case is also scaled by an additional scale factor (SF_δ) of three beyond the initiation of yield. The reduced yield level of 0.119 g is indicated for both the forward and reversed motion.

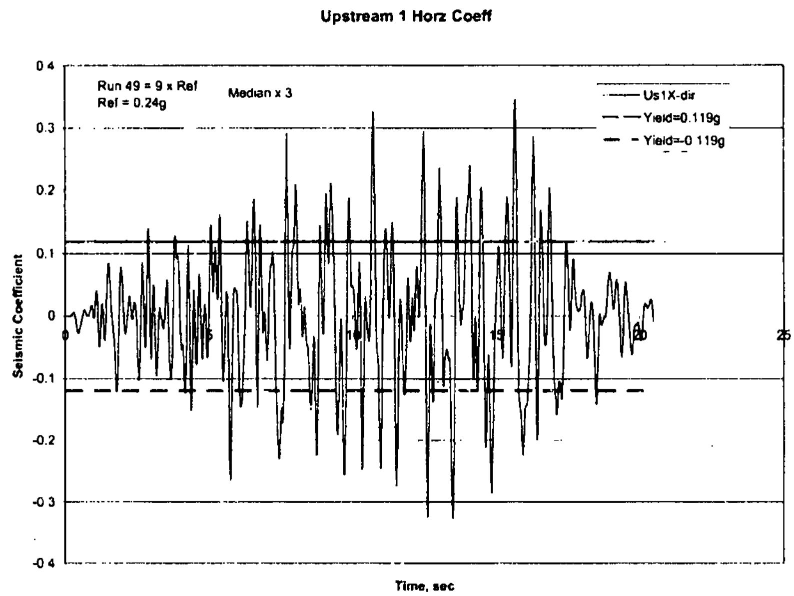

Figure G-2 Response of Us1 Mass for Additional Scaling of Three beyond Median Yield Level

Figures G-3 and G-4 show the resulting series of clipped acceleration pulses that are applied to the sliding masses. As can be noted in Figures G-3 and G-4, the Ds1 pulse history consists of fewer longer duration pulses than does the Us1 pulse history. The resulting relative velocity histories of the sliding masses are shown in Figures G-5 and G-6. The velocity of the Ds1 mass is greater than the Us1 mass. Figures G-7 and G-8 show the resulting relative displacement of the sliding masses

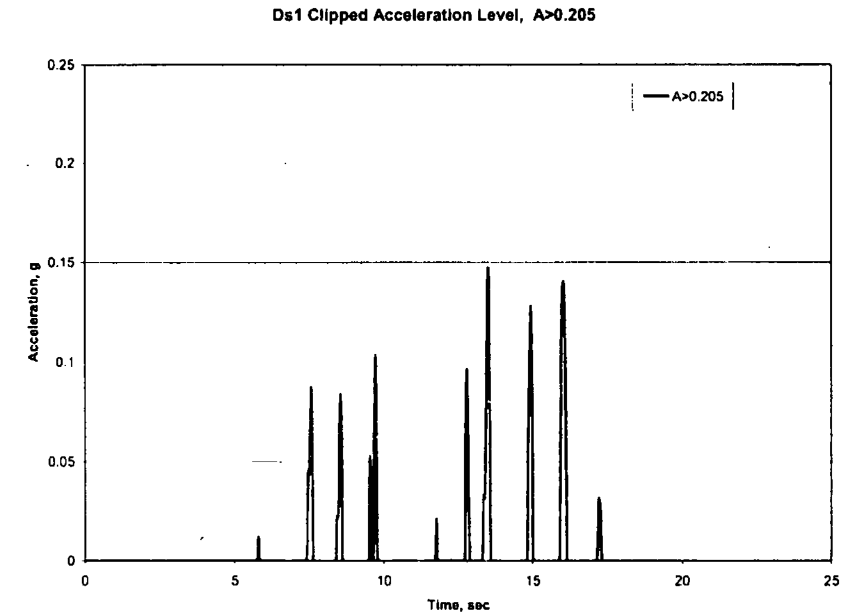

Figure G-3 Clipped Response of Reversed Scaled Ds1 Motion

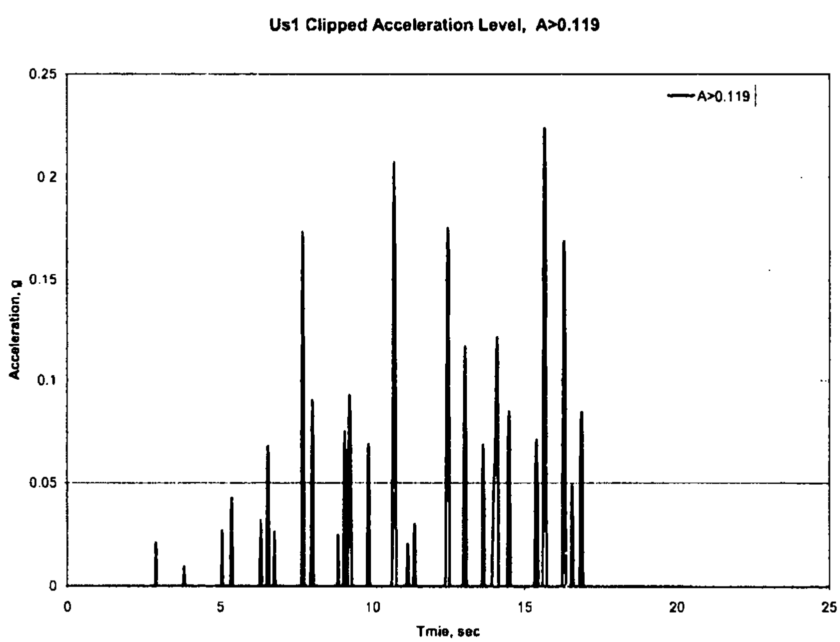

Figure G-4 Clipped Response of Reversed Scaled Us1 Motion

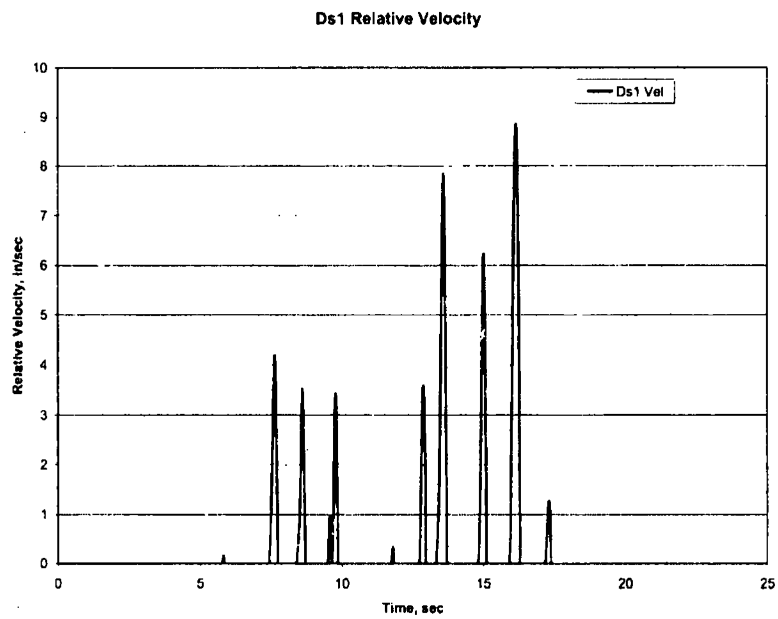

Figure G-5 Relative Horizontal Velocity of Ds1 Mass

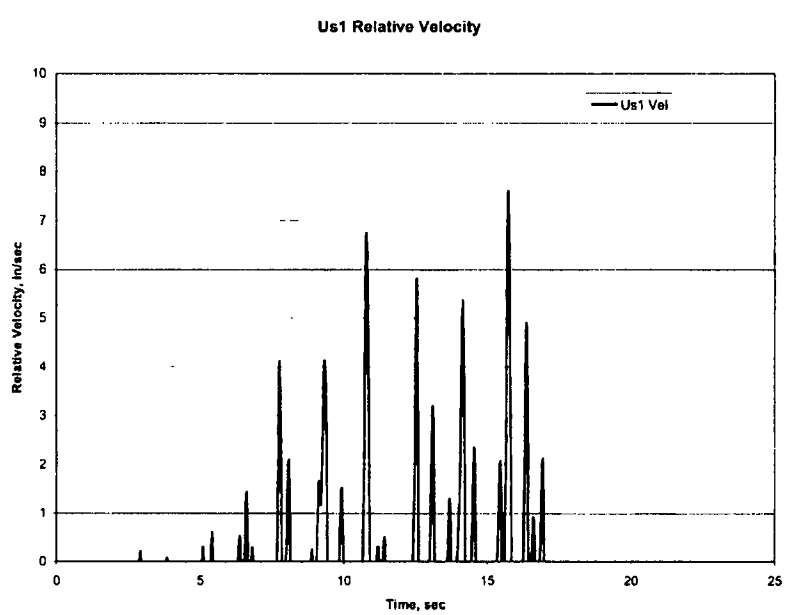

Figure G-6 Relative Horizontal Velocity of Us1 Mass

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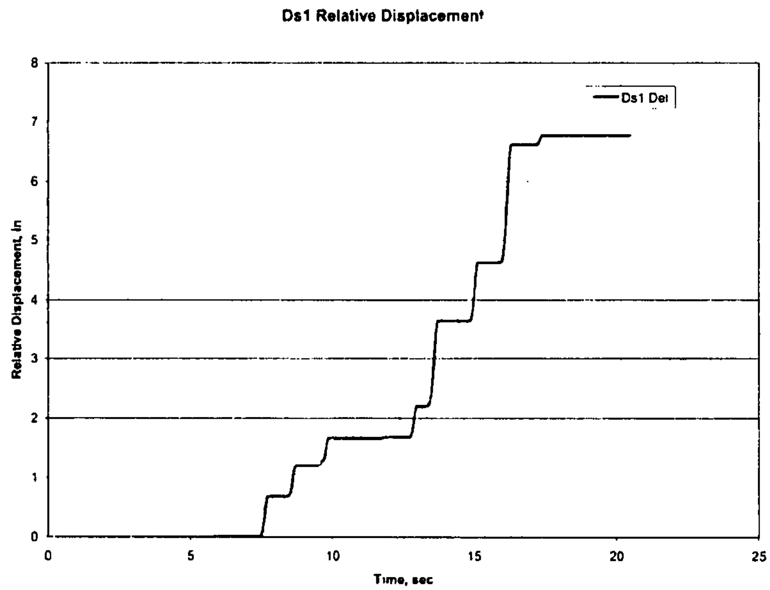

Figure G-7 Relative Horizontal Displacement of Ds1 Mass

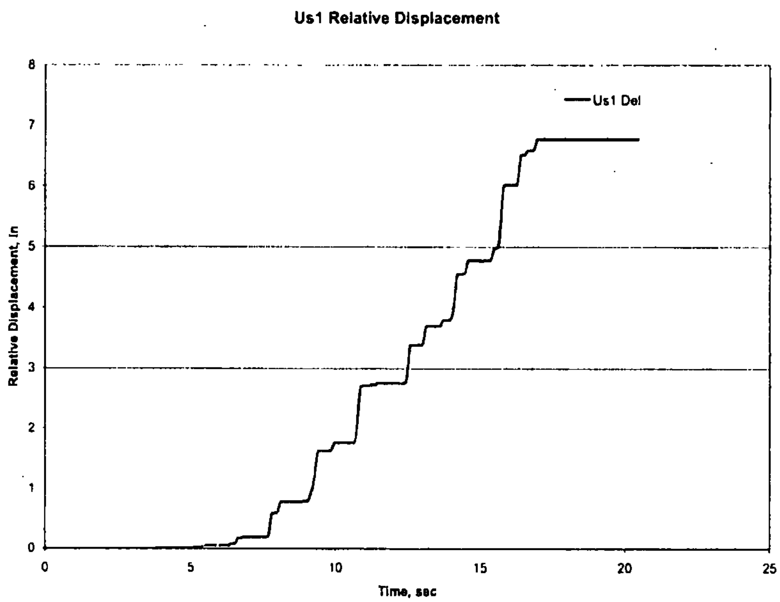

Figure G-8 Relative Horizontal Displacement of Us1 Mass

As can be noted, the additional scaling of three results in a sliding displacements of the Ds1 and Us1 masses which are about six inches considering median material properties. In general, in design, displacements which are less than 12 inches are considered as inconsequential. A slipping motion of two feet has been accepted by FERC as a conservative criterion in prior seismic evaluations of embankment dams. The 1981 seismic fragility evaluation of Jocassee Dam assumed a median failure slippage of three feet based on an estimate of filter fracture displacement. Some international agencies use a value of 1m sliding displacement as acceptable value for dam safety evaluations. Reference G2 indicates that studies have shown that the deformations of embankment dams are fairly minor as long as the PGA of the input motion is less than three times the yield acceleration.

These above examples of Newmark sliding analyses also indicates that it is extremely difficult to achieve median sliding displacements greater than about 6-8 inches by scaling the UHS input motion. In order to calculate the variability of sliding, the above case of 6 inches was chosen as the limiting condition, $\langle SF_\delta \rangle=3$, for both the Ds1 and Us1 masses. The variability in the scaling may be determined using the approximate second moment procedure (Reference G3) which considers the input scale factor necessary to achieve the deformation level given a one sigma variance of each material property. Given the additional scaling results for a one sigma variance in a selected material property is $SF_\delta[1\sigma]$, then the total variability in scale factor for the i^{th} material property is $\beta_i=\ln(\langle SF \rangle \langle SF_\delta \rangle / \{SF[1\sigma] SF_\delta[1\sigma]\})$ where SF is the scaling factor to achieve the yield acceleration ($\langle SF \rangle=3$) and SF_δ is the additional scaling factor to achieve the limit displacement ($\langle SF_\delta \rangle=3$). The total variability is given by $\beta_T=\{\Sigma(\beta_i)^2\}^{1/2}$.

Since the scaling to achieve a sliding displacement is a nonlinear process, several QUAD4M analyses were conducted and the results plotted in Figures G-9 and G-10. The scale factors associated with a 6 inch sliding displacement were then interpolated. The median scale factor for mass Ds1 was 3.0 and the median scale factor for mass Us1 was 2.76.

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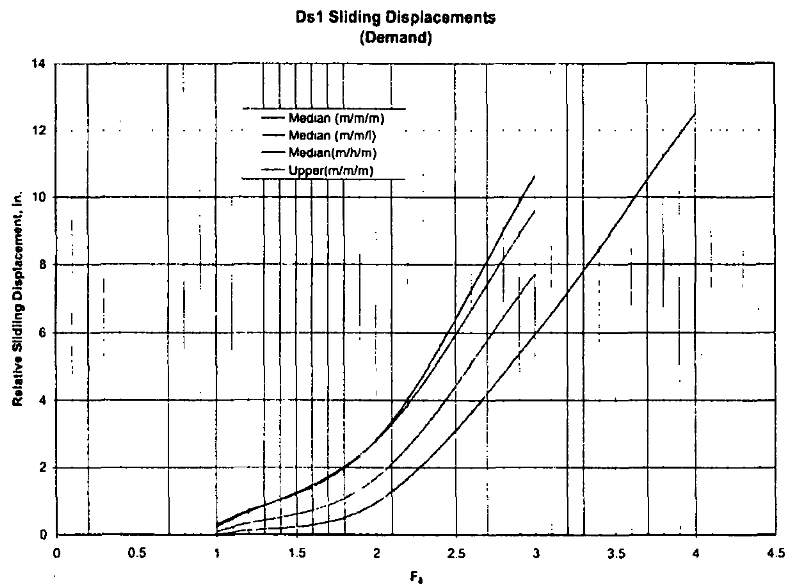

Figure G-9 Plot of Ds1 Sliding Displacement Cases for Median and One Sigma Variation of Material Properties

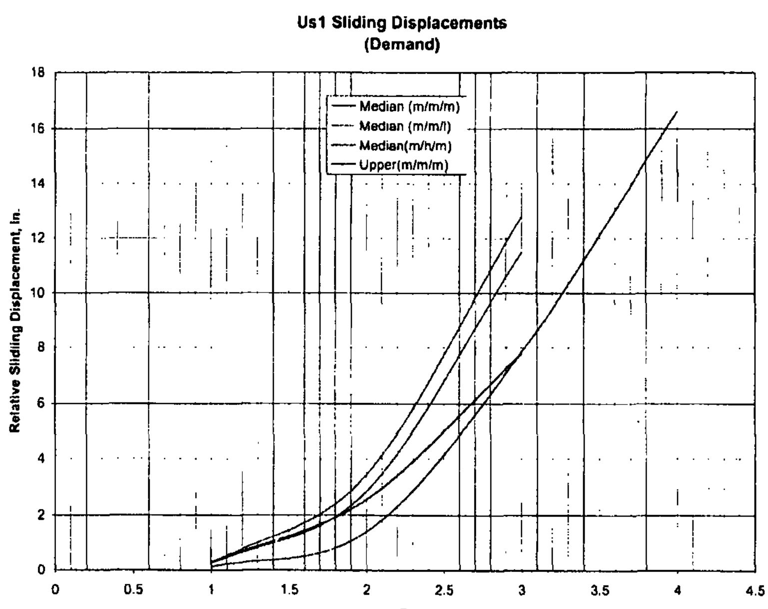

Figure G-10 Plot of Us1 Sliding Displacement Cases for Median and One Sigma Variation of Material Properties

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The following is a summary of the input scaling results for mass Ds1 sliding 6 inches:

Material Property	SF[σ]	$SF_\delta[\sigma]$	β_i
G_{max}	2.55	2.51	0.341
Damping	2.6	2.73	0.237
G/G_{max}	2.79	2.46	0.271
		β_T	0.496

The following is a summary of the input scaling results for mass Us1 sliding 6 inches:

Material Property	SF[σ]	$SF_\delta[\sigma]$	β_i
G_{max}	2.55	2.41	0.298
Damping	2.6	2.32	0.106
G/G_{max}	2.79	2.67	0.275
		β_T	0.448

The above variability cases (median yield level) may be associated with demand. The yield level acceleration (capacity) affects the sliding displacement. Figures G-11 and G-2 show the scaling required to achieve a displacement for a one sigma variance in yield level.

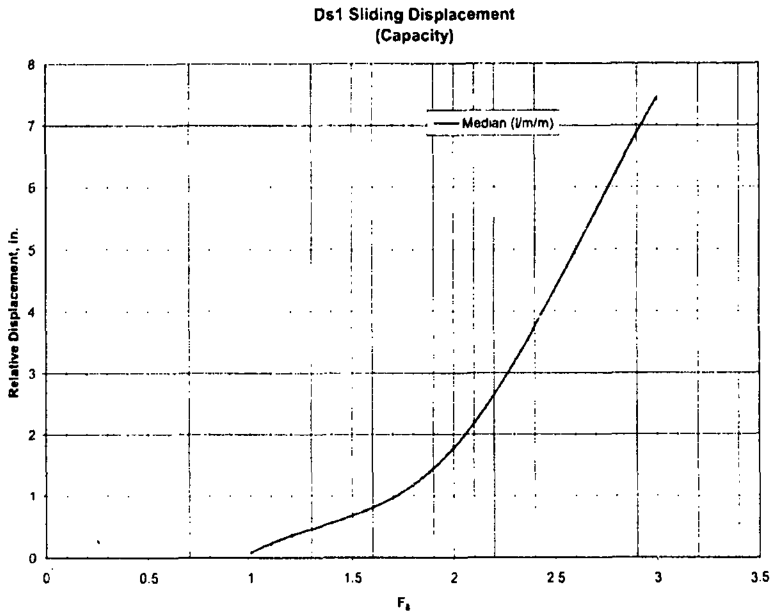

Figure G-11 Plot of Ds1 Sliding Displacement Case for One Sigma Variation of Yield Acceleration

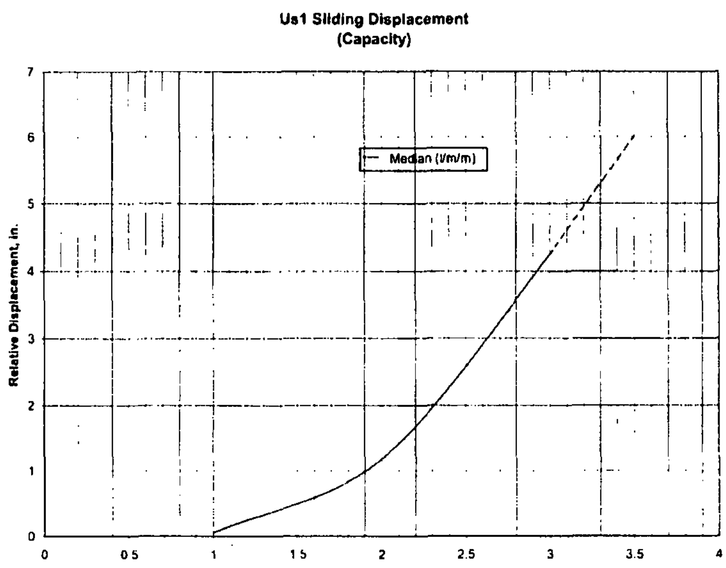

Figure G-12 Plot of Us1 Sliding Displacement Case for One Sigma Variation of Yield Acceleration

The following the input scaling results for mass Ds1 sliding 6 inches considering a variance in yield acceleration:

Variable	**SF[σ]**	**SF_{δ}[σ]**	**β**
Yield Level	2.0	2.76	0.489

The following the input scaling results for mass Us1 sliding 4 inches considering a variance in yield acceleration:

Variable	**SF[σ]**	**SF_{δ}[σ]**	**β**
Yield Level	2.0	2.93	0.239

The above results indicate that it is extremely difficult to achieve "failure" displacements by scaling the UHS input motion. The Uniform Hazard simply lacks sufficient frequency content in the dam response range. In order to demonstrate this, a special case was considered with concurrent one sigma variation in all variables (G_{max}, G/G_{max}, damping, and yield acceleration). This unlikely combination produces a 26.5 inch sliding displacement for an additional scaling factor of three. Thus, an input motion which is 9 (3x3) times the reference motion (PGA_{ref}=0.24), or a PGA = 2.16 g is only capable of producing sliding displacements on the order of design criterion values (24 inches) if the worst case combination of properties are used.

Since the Hazard is only defined to a PGA value of approximately 1g, it is recommended that the sliding criterion for fragility determination be chosen as 2 inch for which the additional median scaling factor is approximately a value of 2.28. The variability would be taken as computed above for the 6 inch displacement case. This would represent a UHS motion scaled to a PGA = 3x2.28x0.24=1.64 g. Thus, the median fragility would be 1.64 g and the HCLPF would represent a high confidence of a low probability that the sliding displacement of a slope mass exceeds
two inches.

As noted previously, the liquefaction potential of the saturated core and random rock materials is judged to be low; however, the increased scaling of the input motion would, at some level, cause this judgment to be questionable. While the core material was highly compacted to a specified Proctor test level (~ >90% relative density), the random rock had judgmental compaction control which likely resulted in a dense to very dense material (~ 85-90% relative density). Reference 4 contains data which compares average cyclic stress ratio (average shear stress/effective overburden stress) to relative density. Using the results of a QUAD4M analysis for the input motion scaled to 6.84 (=3x2.28), the average cyclic stress ratio within the saturated random rock zone of the dam was found to be approximately 0.17. The data of Reference G4 for silty-sands

indicates that liquefaction is not expected at this ratio for relative density values greater than 70%. Thus liquefaction is not likely in the saturated compacted random rock material.

References

G1. Newmark, N.M., "Effects of Earthquakes on Dams and Embankments", Geotechnique, Vol. 15, No. 2, p.p.139-160, 1965.

G2. "Federal Guidelines for Dam Safety: Earthquake Analyses and Design of Dams", FEMA 65, Federal Emergency Management Agency, May 2005.

G3. "Methodology for Developing Seismic Fragilities," EPRI Report TR-103959, June 1994.

G4. Seed, H.B., and Idriss, I.M., "Ground Motions and Soil Liquefaction during Earthquakes", EERI Monograph, Earthquake Engineering Research Institute, 1982.

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ATTACHMENT H
DETERMINATION OF JOCASSEE DAM FRAGILITY

This attachment summarizes the computations and steps for determination of the fragility of Jocassee Dam for use in the probabilistic risk assessment of the Oconee Nuclear Station (ONS). The fragility is presented as the median PGA of a scaled uniform hazard motion, which represents the median hard rock hazard motion of the ONS site as given 1989 EPRI uniform hazard study (Reference H1), and the associated variability of the scaling factor. The median fragility can be presented as A_m=F(PGA_{ref}) where F is a scale factor and PGA_{ref}=0.24 g which is the reference level of UHS compatible time-history motions developed for ONS. The scale factor, F, is the primary fragility variable with variability due to randomness, β_R, and variability due to uncertainty, β_U, and can be, in general, expressed as $F=F_DF_CF_{GM}$ where F_D is the scale factor for demand variability, F_C is the scale factor for capacity variability, and F_{GM} is the scale factor for ground motion variability. The resulting HCLPF is then given as, $HCLPF_{50} = A_m \exp[-1.645(\beta_R + \beta_U)]$, where the subscript "50" denotes that the HCLPF value is referenced to the median UHS spectral shape.

Calculations indicate that the downstream slope Ds1 has the lowest fragility.

Ground Motion Variability

The scale factor F_{GM} may be represented as $F_{GM}=F_{GS}F_{PV}F_{HD}$ where the median values $\langle F_{GS}\rangle$, $\langle F_{PV}\rangle$, and $\langle F_{HD}\rangle$ along with the associated variability are given by the following:

1. F_{GS}: Ground Spectrum Shape Variability
   $\langle F_{GS}\rangle=1.0$, $\beta_R = 0.14$, $\beta_U = 0.10$
2. F_{PV}: Peak & Valley Variability
   $\langle F_{PV}\rangle=1.0$, $\beta_R = 0.20$, $\beta_U = 0.0$
3. F_{HD}: Horizontal Direction Variability
   $\langle F_{GS}\rangle=1.0$, $\beta_R = 0.13$, $\beta_U = 0.0$
4. Combined Variability
   $\langle F_{GM}\rangle=1.0$, $\beta_R = [(0.14)^2+(0.20)^2+(0.13)^2]^{1/2}= 0.277$, $\beta_U = 0.10$

Demand Variability

Sliding Initiation Case

For the case of sliding initiation, the scale factor, F_D, scales the rock input motion until the seismic coefficient of the potential sliding mass with median properties is equal to the median yield acceleration of the mass. The median value $\langle F_D\rangle$ along with the associated variability are given by the following:

Ds1 Slope Mass:
$\langle F_D \rangle = 3.0$, $\beta_R^2 + \beta_U^2 = (0.257)^2$, let $\beta_R = \beta_U/3$,
$\beta_U = 0.244$, $\beta_R = 0.081$
Us1 Slope Mass:
$\langle F_D \rangle = 3.0$, $\beta_R^2 + \beta_U^2 = (0.299)^2$, let $\beta_R = \beta_U/3$,
$\beta_U = 0.283$, $\beta_R = 0.095$

Two Inch Sliding Case

For the case of sliding, the scale factor, F_D, may be represented as $F_D = F_{DI} F_\delta$ where the median value $\langle F_{DI} \rangle$ first scales the rock input motion until the seismic coefficient of the potential sliding mass with median properties is equal to the median yield acceleration of the mass, and then the median value $\langle F_\delta \rangle$ is the additional scaling required to achieve the median target slope deformation which was selected as two inch. The variability, however, is associated with the product of the two factors, or the overall value of F_D. The median value $\langle F_D \rangle$ along with the associated variability are given by the following:

Ds1 Slope Mass:
$\langle F_D \rangle = \langle F_{DI} \rangle \langle F_\delta \rangle = (3.0)(2.28) = 6.84$,
$\beta_R^2 + \beta_U^2 = (0.496)^2$, let $\beta_R = \beta_U/3$,
$\beta_U = 0.471$, $\beta_R = 0.157$
Us1 Slope Mass:
$\langle F_D \rangle = \langle F_{DI} \rangle \langle F_\delta \rangle = (3.0)(2.13) = 6.39$,
$\beta_R^2 + \beta_U^2 = (0.448)^2$, let $\beta_R = \beta_U/3$,
$\beta_U = 0.425$, $\beta_R = 0.142$

Capacity Variability

Sliding Initiation Case

For the case of sliding initiation, the median capacity is the median yield acceleration; thus, the median scale factor, $\langle F_C \rangle$, is unity. The variability is taken as all uncertainty since the yield acceleration is determined by strength properties.

Ds1 Slope Mass:
$\langle F_C \rangle = 1.0$, $\beta_R = 0.0$, $\beta_U = 0.357$

Us1 Slope Mass:
$\langle F_C \rangle = 1.0$, $\beta_R = 0.0$, $\beta_U = 0.256$

Two Inch Sliding Case
For the case of sliding, the level of deformation is also a function of yield acceleration in addition to the material properties considered for the demand case. The scale factor, F_C, is taken as unity; however, the variability is determined in the same manner as the demand case above by considering a one sigma variation of the yield acceleration level.

Ds1 Slope Mass:
$\langle F_C \rangle = 1.0,\ \beta_R^2 + \beta_U^2 = (0.489)^2$, let $\beta_R = \beta_U/3$,
$\beta_U = 0.464,\ \beta_R = 0.155$

Ds1 Slope Mass:
$\langle F_C \rangle = 1.0,\ \beta_R^2 + \beta_U^2 = (0.239)^2$, let $\beta_R = \beta_U/3$,
$\beta_U = 0.227,\ \beta_R = 0.076$

Fragility Determination

Sliding Initiation Case
For the case of sliding initiation of Ds1, the median scale factor is given by:

$$\langle F \rangle = \langle F_D \rangle \langle F_C \rangle \langle F_{GM} \rangle = (3.0)(1.0)(1.0) = 3.0$$

With combined variability:

$$\beta_U = \{(0.244)^2+(0.357)^2+(0.100)^2\}^{1/2} = 0.444$$
$$\beta_R = \{(0.081)^2+(0.277)^2\}^{1/2} = 0.289$$

The median PGA of the hard rock hazard motion of the ONS site that causes sliding initiation of Ds1 is:

$$A_m = F\,(PGA_{ref}) = (3.0)\,(0.24g) = 0.72\ g$$

with

$$HCLPF_{50} = A_m \exp[-1.645(\beta_R + \beta_U)] = 0.22\ g$$

For the case of sliding initiation of Us1, the median scale factor is given by:

$$\langle F \rangle = \langle F_D \rangle \langle F_C \rangle \langle F_{GM} \rangle = (3.0)(1.0)(1.0) = 3.0$$

With combined variability:

$$\beta_U = \{(0.283)^2+(0.256)^2+(0.100)^2\}^{1/2} = 0.394$$
$$\beta_R = \{(0.095)^2+(0.277)^2\}^{1/2} = 0.293$$

The median PGA of the hard rock hazard motion of the ONS site that causes sliding initiation of Us1 is:

$$A_m = F\,(PGA_{ref}) = (3.0)\,(0.24g) = 0.72\ g$$

with

$$HCLPF_{50} = A_m \exp[-1.645(\beta_R + \beta_U)] = 0.23 \text{ g}$$

Two Inch Sliding Case
For the case of two inch sliding of the Ds1 mass, the median scale factor is given by:

$$\langle F\rangle = \langle F_D\rangle \langle F_C\rangle \langle F_{GM}\rangle = (6.84)(1.0)(1.0) = 6.84$$

With combined variability:

$$\beta_U = \{(0.471)^2+(0.464)^2+(0.100)^2\}^{1/2} = 0.669$$
$$\beta_R = \{(0.157)^2+(0.155)^2+(0.277)^2\}^{1/2} = 0.354$$

The median PGA of the hard rock hazard motion of the ONS site that causes a sliding displacement of 2 inches is:

$$A_m = F\ (PGA_{ref}) = (6.84)\ (0.24g) = 1.64 \text{ g}$$

with

$$\boldsymbol{HCLPF_{50} = A_m \exp[-1.645(\beta_R + \beta_U)] = 0.305 \text{ g}}$$

For the case of two inch sliding of the Us1 mass, the median scale factor is given by:

$$\langle F\rangle = \langle F_D\rangle \langle F_C\rangle \langle F_{GM}\rangle = (6.39)(1.0)(1.0) = 6.39$$

With combined variability:

$$\beta_U = \{(0.425)^2+(0.227)^2+(0.100)^2\}^{1/2} = 0.492$$
$$\beta_R = \{(0.142)^2+(0.076)^2+(0.277)^2\}^{1/2} = 0.320$$

The median PGA of the hard rock hazard motion of the ONS site that causes sliding displacement of two inches is:

$$A_m = F\ (PGA_{ref}) = (6.39)\ (0.24g) = 1.53 \text{ g}$$

with

$$\boldsymbol{HCLPF_{50} = A_m \exp[-1.645(\beta_R + \beta_U)] = 0.402 \text{ g}}$$

Summary

As can be noted, the HCLPF for US1 is greater than the HCLPF of DS1. In general this implies that DS1 has the lowest fragility. This can be verified by plotting the conditional probabilities of failure for the two modes of failure as shown in Figure H-1. For PGAs less than 1.4 g, the probability of failure of the Ds1 mass is greater than the Us1 mass.

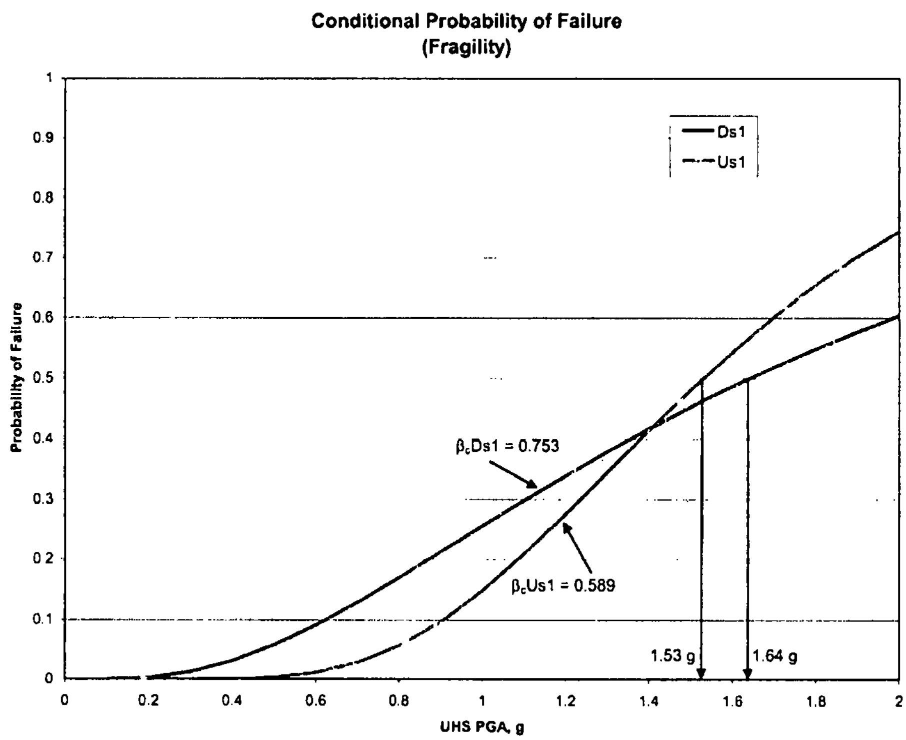

Figure H-1. Conditional Probability of Failure of Dam Slopes

References

H1. "Methodology for Developing Seismic Fragilities," EPRI Report TR-103959, June 1994.

Attachment to 07SA01014
January 29, 2007

ATTACHMENT I
DEVINE TARBELL & ASSOCIATES LETTER REPORT

Devine Tarbell & Associates, Inc.
Consulting Engineers, Scientists, & Regulatory Specialists

Principals:
John J. Devine, P.E., President
John C. Tarbell, P.E.
James M. Lynch
Edwin C. Luttrell, P.E.

January 29, 2007

217.0001.0000

ARES Corporation
Attn: Kelly Merz
5 Hutton Center Drive
Suite 610
Santa Ana, CA 92707

Subject: **Jocassee Dam Fragility Analysis**
Supporting Calculations

Dear Mr. Merz:

As requested, Devine Tarbell & Associates, Inc. (DTA) has completed the supporting calculations for the Jocassee Dam Fragility Analysis. The calculations consisted of slope stability analyses, estimation of yield accelerations for selected failure surfaces, and pseudo-static Newmark type deformation analyses. The following discussion and enclosed DTA calculations, ARES-FAS-001 and -002, summarize the results of the analyses performed in support of the overall fragility analysis project.

The supporting analysis was subdivided into three tasks, including a review of available documents in our library, slope stability analyses, and the Newmark seismic displacement analyses. The review of available documents in our possession relevant to the Jocassee Dam was performed and results were sent under a cover letter dated August 31, 2006. The remainder of the tasks and analyses are presented in this letter and the enclosed documents.

Liquefaction Susceptibility

DTA was asked to provide an opinion regarding the liquefaction susceptibility of the materials comprising the embankment structure of Jocassee Dam. Based on the review of the documents in our possession, the materials in the embankment generally consist of a sandy rockfill shell and sandy silt core. Because of the difficulty of sampling these materials, little information is available regarding quantitative measures of the relative density at which these materials were placed.

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Boise, Idaho 208.319.1977

DTA

However, based on limited information, laboratory tests, and statements made in the documents reviewed, the core materials and rockfill with a large quantity of silty sand in the soil matrix would be expected to develop some excess pore pressures during seismic loading. The gradation of the cleaner rockfill would appear to preclude the buildup of significant excess pore pressures.

Although DTA did not have quantitative information regarding the densities of these materials, certain statements in the documents convey that the designers of the embankment considered the possibility of excess pore pressures in the core and sandy rockfill. The construction specifications for the embankment required construction methods and quality control and oversight measures that, if properly applied, should have resulted in the materials being placed in a relatively well-compacted manner. Extensive subsurface exploration and a detailed analysis would be required to fully investigate the liquefaction susceptibility of these materials. Because of the sandy and gravelly nature of these materials, liquefaction of small, isolated zones may be anticipated during a large seismic event. However, based on a review of the limited information available, we found no significant information that would suggest a strong potential for significant liquefaction of these materials.

Slope Stability Analyses

The objective of the slope stability analyses was to provide representative failure surfaces for the Jocassee Dam embankment based on the cross-section and material properties provided by ARES. The selected material properties, including the K_{2max} values, appeared to be reasonable based on DTA's experience with regional materials. The purpose of the analysis was to locate failure surfaces which encompass approximately one-third, two-thirds, and essentially the entire height of the embankment. The analysis was performed for both the upstream and downstream slopes, and was intended to yield failure surfaces that would likely result in a loss of the reservoir. As discussed in DTA Calculation No. ARES-FAS-001, the critical failure surfaces, or surfaces with the lowest safety factors, for this embankment are very shallow, infinite type failures. Therefore, a manual search was conducted to locate the failure surfaces presented in the referenced calculation. The analysis was performed using UTEXAS4. Further details regarding the analysis may be found in the referenced calculation, enclosed with this letter.

Using the representative failure surfaces, yield accelerations were estimated with UTEXAS4 by progressively increasing the seismic coefficient until a slope stability safety factor of approximately unity was achieved. Based on the results of this phase of the analysis, ARES Corporation selected two downstream and two upstream failure surfaces for further analysis. These four failure surfaces were analyzed using additional shear strength envelopes representing upper and lower bounds for the embankment materials. Using UTEXAS4, yield accelerations were estimated for each failure surface and respective shear strength envelopes to include the lower bound, median, and upper bound. Additional details and discussion regarding this analysis may be found in DTA Calculation No. ARES-FAS-002.

DTA

Pseudo-Static Displacement Analyses

The final task associated with supporting the Jocassee Dam fragility analysis was to perform Newmark type displacement analyses based on provided time histories. The time histories were developed by ARES Corporation using QUAD4M and the previously developed failure surfaces. Utilizing selected time histories and respective yield accelerations, the pseudo-static displacement analyses were performed with the program TNMN, which double integrates the difference between the input time history and yield acceleration to approximate the cumulative displacement along the assumed failure surface. Further details and discussion regarding these analyses may be found in DTA Calculation No. ARES-FAS-002.

DTA appreciated the opportunity to be of service to you on this project, and looks forward to working with ARES Corporation on future projects. If you have questions or concerns regarding the contents of this letter or the enclosed calculations, please feel free to call me at (704) 342-7313.

Sincerely,

DEVINE TARBELL & ASSOCIATES, INC.

Brian F Chrisman

Brian F. Chrisman, P.E.
Geotechnical Engineer

BFC
Enclosures:
DTA Calculation No. ARES-FAS-001
DTA Calculation No. ARES-FAS-002

cc: Project File

U.S.NRC

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Final Regulatory Assessment of Oconee Flood Barrier Issue

October 1, 2007

U.S.NRC

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Overview

- Objective
  - Reach agreement on path forward for Oconee flood barrier regulatory issues.
- Success
  - Understanding the flood barrier finding and related scenarios.
  - Understanding the associated regulatory issues.
  - Define and agree to path forward for resolution of each regulatory issue.

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Timeline of SDP

- August 17, 2006 - SERP meeting assessed as preliminary WHITE based on a blended qualitative and quantitative risk-informed approach (pre-MC 0609 App M).
- August 31, 2006 - Choice letter sent to licensee.
- October 5, 2006 – Licensee provided written response to choice letter and waived regulatory conference.
- Nov. 22, 2006 - Final significance determination issued. WHITE based on qualitative erosion of defense-in-depth, but includes quantitative CDF based on apportioning flood frequency to flood height.
- December 20, 2006 - Licensee appeals the final significance determination. Requests NRC to accept incomplete, un-docketed new information.
- January 9, 2007 - Appeal panel convened
- March 1, 2007 – Appeal panel upholds WHITE finding.
- May 3, 2007 – Licensee requests reassessment of final significance determination.
- June, 2007 – Assembled a team to review new information. Flooding expert review of data on random dam failure.
- June 22, 2007 – Reassessment of final significance determination assigned to RII.
- June 28, 2007 - Follow up telecom with Licensee on dam failure questions and comments.
- July 17, 2007 - Licensee response to analysis questions by email.

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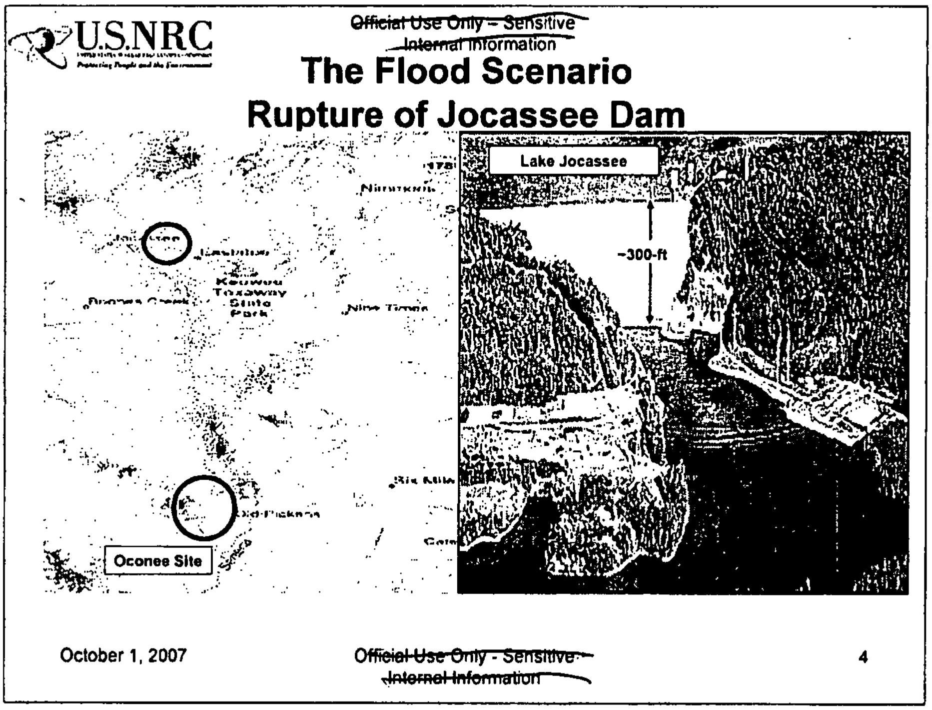

River miles are approximately 14 miles.

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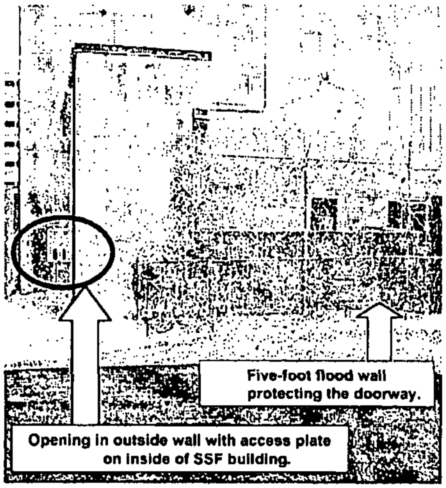
The Flood Barrier Finding



- Licensee opened an access cover uncovering a previously cut hole in the wall on August 13, 2003.
  - Should have done a 10CFR50.65 (a)(4) assessment immediately.
  - Should have done a 10CFR50.59 evaluation after 90 days.
- Licensee opportunities to identify issue
  - June 2, 2005 NRC inspectors notified the licensee of condition. Licensee issued PIP (condition report in their corrective action system). Corrective action not taken.
  - August 3, 2005 NRC inspectors questioned lack of corrective action and licensee issued a further PIP.
- Opening sealed on August 3, 2005.

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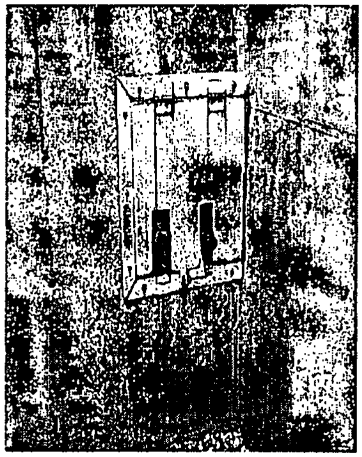

- Photo 3 (Flood Flowpath #1): Hinged, Exterior Access Panel for SSFCO-14 and SSF-CO-17

- Photo 4 (Flood Flowpath #1): View of 6" x 10" interior access panel (flood barrier), signage and 208V MCC 3XSF-1

October 1, 2007

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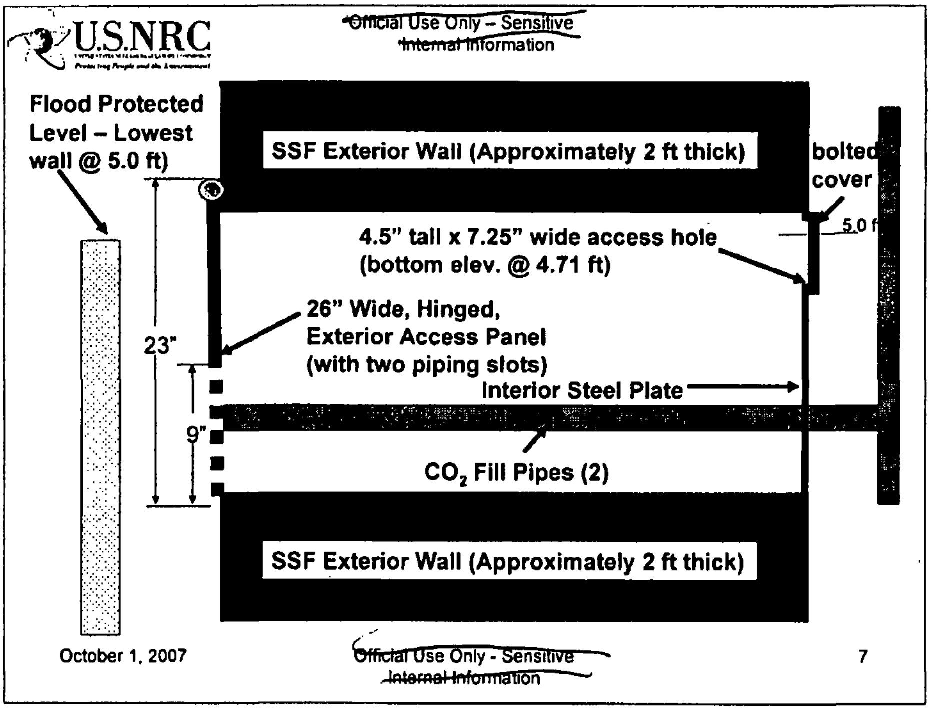

Note: The licensee surveyed the SSF and associated flood walls and provided an estimate that the lowest level of protection was at 801.0' msl. There was some initial discrepancies on the dimensions when NRC sent the preliminary white finding to the licensee in 2006. In order to resolve these differences, the licensee removed the interior bolted cover last October, and the resident inspectors verified the elevations and dimensions noted above.

Reference points	Elevation (feet msl)
Oconee Yard Grade	**796.00**
Ground floor of SSF	**797.00**
Bottom of breached flood barrier	**800.71**
Top of SSF North flood wall	**801.00**
Top of SSF South flood wall	**801.75**

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Assessment of Proposed Violation

- Quantitative ROP evaluation
  - Using ROP process
    - (b)(7)(F)
    - Likelihood of floodwater entering the SSF.
      - Poor state of documentation for basis of flood height protection
      - Distribution of flood height highly uncertain
    - Probability of core damage
      - If floodwater enters the SSF, the probability of core damage is essentially unity.
    - Recovery
      - No timely recovery possible.
  - Quantitative evaluation not dispositive for significance determination.
    - Sensitivity studies using estimated and uniform distributions to inform qualitative assessment (Slides 10 and 11)

- Qualitative evaluation
  - Using ROP process
    - Defense in depth
      - SSF only mitigating system for preventing core damage at all three units.
      - No redundancy or diversity of mitigation.
      - Loss of multiple barriers to protect public
    - Safety margins
      - None left.
    - Recovery
      - No timely recovery possible.

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- Qualitative decision-making attributes are in accordance with numerous NRC guidance documents on risk-informed integrated decision-making (e.g., Regulatory Guide 1.174, SDP Appendix M, SDP IMC 308 (SDP basis document), LIC504, etc…).

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Review of Data of Random Jocassee Dam Failure

- Licensee
  - Assumed 3 failures in 220,080 dam-years which yielded a frequency of ~1.4 x 10^{-5} per year.
- NRC
  - Reviewed the licensee dam failure data.
  - Licensee inappropriately used data for all rockfill, composite rockfill-earthen, and earthen dams over 50-ft matching Jocassee in the denominator with failures of rockfill only dams in the numerator.
  - (b)(7)(F)

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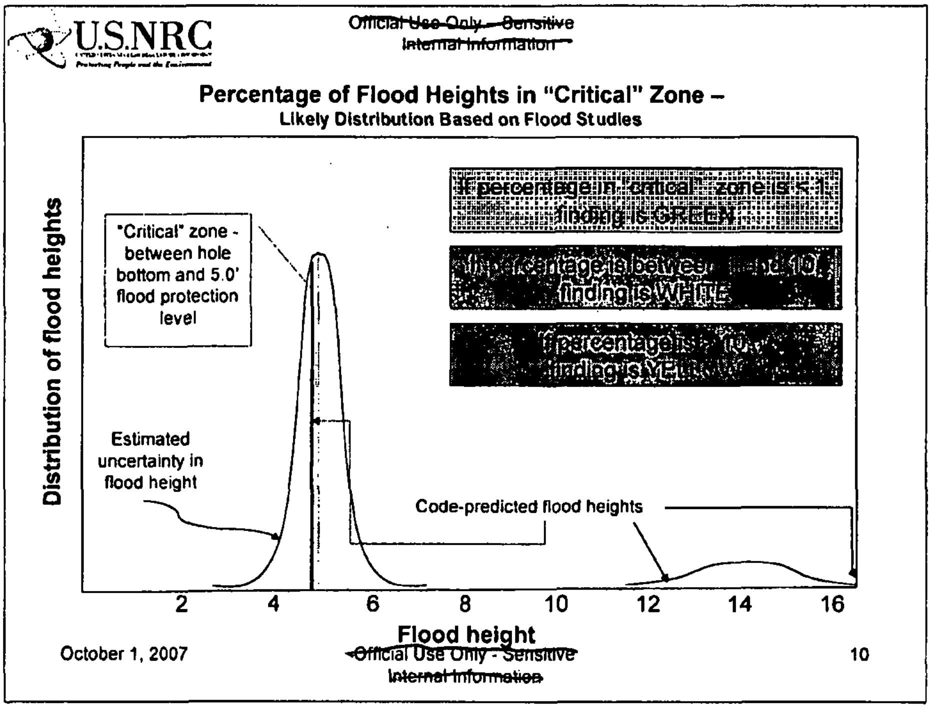
- Correcting Duke's calculation results in a point-estimate of 1.92e-4/yr frequency when properly matching the numerator definition to what Duke used in the denominator of all Dams over 50 ft.

- The staff's best estimate is the Bayesian mean (state of the art approach). The 90 percent credible interval is the [5^{th}, 95^{th}] values. Assessment assumes rockfilled dams only.



Note: The 1983 study estimated flood level at 4.7 ft. Using the DAMBRK code, the Duke/FERC study in 1992 cited values for the sunny day dam break at 12.51 ft and for the probable maximum flood at 16.82 ft.

Total area under both curves = 1.0. Area under the curve for the 5' flood height approximately 0.8. Area under the curve for the 12' to 16' flood height approximately 0.2.

Change in CDF in terms of $Pr_{\text{flood critical zone}}$, probability of floods occurring in the "critical zone" using simplified risk calc:

$\Delta CDF = CDF_{\text{non-conforming}} - CDF_{\text{baseline}}$

$= (IEF_{\text{Jocasee Break}} * Pr_{\text{flood critical zone}} * CCDP_{\text{SSF flood unprotected}}) -$
$(IEF_{\text{Jocasee Break}} * Pr_{\text{flood critical zone}} * CCDP_{\text{SSF flood protected}})$

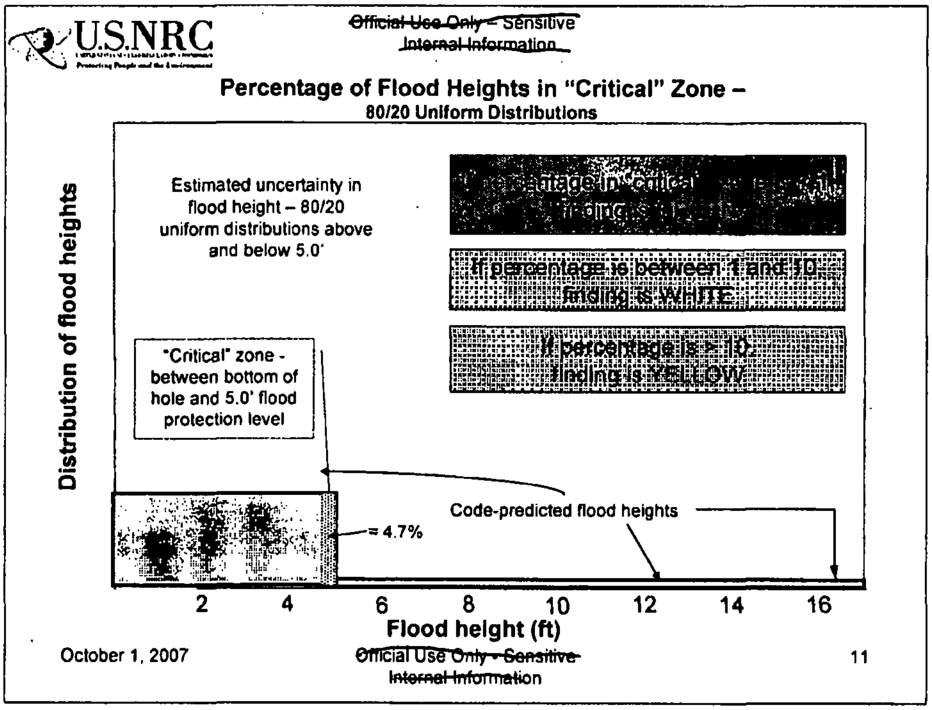
$= IEF_{\text{Jocasee Break}} * Pr_{\text{flood critical zone}} * (CCDP_{\text{SSF flood unprotected}} - CCDP\ SSF_{\text{flood protected}})$

$= 1.8E\text{-}4/yr * Pr_{\text{flood critical zone}} * (1.0 - 0.3)$

$\Delta CDF = 1.26E\text{-}4/yr * Pr_{\text{flood critical zone}}$

SDP color thresholds in terms of $Pr_{\text{flood critical zone}}$:

White: 1e-6/1.26e-4 = 0.0079 or ≈ 1 percent
Yellow 1e-5/1.26e-4 = 0.079 or ≈ 10 percent



80 percent of flood distributed below 5.0' mark. The 80/20 split is based on the Duke PRA assessment (1990s). The assumption of uniform distributions is provided here only for a relative non-conservative perspective to the previous slide that has a bimodal distribution.

Likelihood of flood between 4.71' and 5.0' is:

0.8 * (3.5"/60") = 0.0466

Using 1.8e-4/yr for Jocassee Dam break frequency and a 0.047 probability of floods in the critical zone, and a nominal SSF unavailability of the SSF (test& maintenance, system unreliability, or human error) yields an estimated delta CDF (full calc not shown) of:

<u>1.26e-4/yr * 0.047 = 5.9e-6/yr</u>   White finding

Likely distribution of flood height expected to be greater than 4.7% in the "critical zone."

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Recommended Path Forward

- Proposed resolution of significance determination
  - Affirm White significance determination based on quantitative sensitivity study and qualitative considerations
- Pursue additional regulatory issues:
  - Pursue backfit evaluation regarding flood barrier height (NRR lead, Region II support)
  - Ensure licensing basis reflects flood hazards and protection (NRR lead, Region II support)
  - Coordinate with NSIR on security/Comprehensive Review concern (NRR)
  - Evaluate lessons learned from this significance determination (NRR, Region II)
    - Initiation event frequency
    - Application of qualitative factors
    - Evaluate impact of dam failure initiating event frequency issue on industry IPEEE

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NUREG-1742 identified only two IPEEEs that addressed dam failure floods quantitatively – Ft. Calhoun and Diablo Canyon. Everyone else only addressed probable maximum precipitation and screened out dam failure as low probability. Unfortunately, there were few dam failure data sources around back then, so many plants used the estimate published in NUREG/CR-5042. The data source for the estimate in NUREG/CR-5042 was the Oconee PRA - NSAC/60. The calculation in NSAC/60 was done in error and it propagated throughout the industry.

References:

NUREG/CR-5042, "Evaluation of External Hazards to Nuclear Power Plants in the United States.

NUREG-1742, "Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program

NSAC/60, "Oconee PRA"

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DROP-IN VISIT

DUKE ENERGY

WITH

CHAIRMAN KLEIN

COMMISSIONER JACZKO

MAY 21, 2008

ML081350711

Table of Contents

DROP-IN VISIT AGENDA

May 21, 2008

ITINERARY

TIME	PERSON VISITED	CONTACT PERSON	EXTENSION
2:30 PM - 3:30 PM	Commissioner Gregory Jaczko	Annie Bennette	415-1830
4:00 PM- 4:30 PM	Chairman Dale Klein	Linda Herr	415-1759

VISITORS REPRESENTING DUKE ENERGY

Dhiaa M. Jamil, Group Executive and Chief Nuclear Officer, Duke Energy Corporation

James J. Fisicaro, Director Regulatory Relations Nuclear Generation, Duke Energy Corporation

TOPICS OF DISCUSSION

- Introduction of new CNO
- Efforts to improve operating plants performance
- Maintaining high INPO Standards
- Discussion of Duke's reorganization
- William States Lee activities
- Key issues regarding Lee --- Water usage, segregation of impacts

FACILITY DATA

Current Issues

Drop-in Briefing Sheet
Catawba Nuclear Station
Date: May 7, 2008

Current Plant Performance

- Units 1 & 2 are in the Licensee Response Column of the NRC Action Matrix with no greater than Green inspection findings or performance indicators for either unit. All Cornerstone objectives have been met.
- Substantive cross-cutting issue(s): None

Key Messages or Themes

- Inadequate Procedure Use and Adherence - The inspectors noted in the mid-cycle and end-of-cycle debriefs that a trend has re-emerged associated with inadequate procedure use and adherence. This trend has been identified through inspector observations of l activities performed by licensee personnel in multiple work groups (i.e., Operations, Chemistry and Maintenance). The observations included individuals not performing procedural steps as written, missing notes in procedures which affected the results, not performing inspections as stated in the procedure, and not performing corrective maintenance in accordance with the procedure. The licensee has also recognized this trend, based on the observations and feedback provided to them by the inspectors, and is working on developing actions to address this deficiency. Operations has taken punitive actions in some cases, and has been the site leader in attempting to turn this trend around. The inspectors will continue to focus on this behavior trait while conducting inspections in 2008.

Items of Interest

1. **Organizational issues**
   - Management Changes - Dhiaa Jamil succeeded Brew Barron as Chief Nuclear Officer effective February 17, 2008; Gary Peterson became Vice President, Fleet Performance Oversight and Strategy; Bruce Hamilton succeeded Gary Peterson as Vice President, McGuire Nuclear Station effective January 1, 2008; and David Baxter succeeded Bruce Hamilton as Vice President, Oconee Nuclear Station.
   - William States Lee III Nuclear Station - Duke Energy submitted a 10 CFR 52 application for a combined operating licensee (COL) to the NRC on December 13, 2007, which was docketed on February 25, 2008. The license application references the Westinghouse AP1000 pressurized water reactor as the reactor type. The location is southeast of Gaffney, South Carolina.
2. **Plant equipment issues**
   - Tritium - On October 8, 2007, elevated levels of tritium were detected in one of the newly-installed ground water monitoring wells within the Protected Area. Measured levels were approximately twice the Environmental Protection Agency (EPA) limit for drinking water (~42,000 pCi/L vs. 20,000 pCi/L). The State of South Carolina and the NRC were notified as required by the Nuclear Energy Institute's Groundwater Monitoring

Initiative communication plan. Additional sampling was performed by the licensee (within the Owner Controlled Area) and by the South Carolina Department of Health and Environmental Control (SC DHEC) in off-site wells with no samples showing values approaching the EPA limit. A public meeting was held on December 6, 2007, to discuss the issue and answer questions from local residents. The licensee and SC DHEC are continuing to take samples to determine if any migration of tritium is taking place.

3. **Recent Plant Events**
   - None noteworthy
4. **Inspection findings**
   - Identification, Assessment & Management of Risk - There were three Green non-cited violations (NCVs) issued against 10 CFR 50.65(a)(4) in 2007 as well as two minor violations. This follows three (a)(4) NCVs for the same issue in 2006. The station is struggling with implementing a solid program to ensure activities and issues are properly screened to identify and assess increased risk resulting from them and then developing and implementing appropriate risk management actions to minimize the risk that the activities/issues produce. The resident inspectors continue to provide additional attention in this area and have performed more than the nominal baseline inspection sample size for both 2006 and 2007. This focus will continue in 2008 and will be accelerated during the upcoming Unit 1 refueling outage. Regional management has discussed the risk management subject with station management when they have been on-site and plans are to continue these discussions at the highest level of station management to ensure the importance of managing risk is clearly understood.
5. **Allegations**
   - None noteworthy
6. **Safety Culture/SCWE**
   - None
7. **Security Issues**
   - None
8. **Significant industry issues**
   - See attached articles

Drop-in Briefing Sheet
McGuire Nuclear Station
Date: May 7, 2008

Current Plant Performance

- Units 1 & 2 are in the Licensee Response Column of the NRC Action Matrix with no greater than Green inspection findings or performance indicators for either unit. All Cornerstone objectives have been met.
- Substantive cross-cutting issue(s): None

Key Messages or Themes

- Updated Final Safety Analysis Report (UFSAR) - The inspectors previously identified a trend associated with numerous violations for failing to update the UFSAR in accordance with regulations outlined in 10 CFR Part 50.71(e). The licensee initiated a corrective action document to address the UFSAR accuracy trend and performed a sample review of the UFSAR. During the last 6-month period, several additional examples of UFSAR inaccuracies were identified by the NRC. An NRC Inspection Report (IR), identified that the UFSAR had been inappropriately updated to delete the ice fusion licensing basis. For Unit 2, an NRC IR identified an additional example where the UFSAR was not updated to reflect that emergency core cooling system (ECCS) throttle valves were the smallest opening in the ECCS system instead of the containment sump screen. The same example was identified for Unit

Items of Interest

9. Organizational issues
- Management Changes - Dhiaa Jamil succeeded Brew Barron as Chief Nuclear Officer effective February 17, 2008; Gary Peterson became Vice President, Fleet Performance Oversight and Strategy; Bruce Hamilton succeeded Gary Peterson as Vice President, McGuire Nuclear Station effective January 1, 2008; and David Baxter succeeded Bruce Hamilton as Vice President, Oconee Nuclear Station.

10. Plant equipment issues
- Tritium - In response to the industry initiative, the licensee installed numerous ground water monitoring wells. One of these wells recently had higher tritium, which could only have come from a leak in the liner from the final settling pond. The licensee pumped out the pond and is removing sludge in order to identify the location of the liner leak. The pond will not be used until the leak is repaired.
- National Fire Protection Agency (NFPA) 805 - McGuire is in its 3rd year of transitioning to NFPA 805. Triennial Fire Protection Inspection 71111.05P was completed in 12/2006 and the License Amendment Request is scheduled to be complete by 12/2008. Oconee and Catawba are also transitioning, with projected completion in 2008 and 2010 respectively.

11. Recent Plant Events
- None noteworthy

12. Inspection findings
- Unresolved Item on Nuclear Service Water (RN) Strainer Fouling - On August 6, 2007, the licensee identified that the procedures for performing a manual backwash of the RN strainers (installed immediately upstream of the RN pumps) directed operators to use

the non-seismically qualified, non-safety-related instrument air (VI) system to manipulate the valves required for the manual backwash function. The backwash procedures were written as part of a late 2003 plant modification to upgrade and reclassify the RN filtering and backwash functions to "safety-related," in response to NRC concerns of increased Alewife fish concentrations in Lake Norman that could cause the loss of nuclear service water pumps. In addition to the reliance on non-safety-related VI, this modification also relied on other non-safety-related instrumentation and components for performing safety-related backwashes, including the UFSAR-credited differential pressure instrument. As such, strainer backwashes could not readily be accomplished upon: (1) a loss of coolant accident (due to isolation of VI to backwash discharge valves from an SI signal); (2) a loss of offsite power when diesel driven VI compressors are not available (due to a loss of power to the motor driven VI compressors); or (3) a loss of VI (due to a VI pipe break/leak). The licensee immediately installed a temporary modification to restore safety-related manual backwash capability. In addition, the licensee submitted a Licensee Event Report in October 2007 to report this issue with a risk significance of greater than 1.0E-6. A Phase 2 analysis has been completed by the resident staff resulting in a greater than green risk assessment. A Phase 3 analysis is being conducted by the Region SRA at this time.

13. Allegations/2.206 Petitions

- On March 24, 2008, the NRC received a letter requesting that the Agency take enforcement action against McGuire pursuant to 10 CFR 2.206. The petitioner requested that McGuire Unit 2 not start up due to a potential melt down. The concern was a potential for a massive number of tubes in the u-bend section of any of the "A" feed water heaters on both units to rupture due to broken top support plates. A pre-Petition Review Board (PRB) was convened on March 26, 2008, and it was determined that no immediate actions were necessary and that existing analyses in the licensee's updated final safety analysis report bound the scenario described by the petitioner. Following discussions with the petitioner and a public meeting, the PRB met again on April 23, 2008, and concluded that the petition request did not meet the criteria for a review in accordance with 10 CFR 2.206 due to insufficient details of how the failure of non-safety related equipment in the turbine building could cause a core melt down, in light of: (1) control room and emergency diesel generator room missile protection design/orientation; (2) licensing basis turbine missile analysis; (3) the existence of check and automatic isolation valves in the subject bleed steam lines, as well as level-controlled heater drain pumps; and (4) periodic eddy-current testing of the subject feedwater heaters.

14. Safety Culture/SCWE

- None

15. Security Issues

- On October 16, 2007, an off duty McGuire security officer committed suicide. The case was investigated by the Charlotte-Mecklenburg Police. Region II inspected the issue and based on information evaluated during the inspection, it appears the licensee followed procedures and no aberrant behavior had been observed by his supervisors or fellow security officers. At the time of his death, the victim was under investigation by the local law enforcement agency due to allegations of misconduct but no charges had been filed.

Drop-in Briefing Sheet
Oconee Nuclear Station
Date: May 7, 2008

Current Plant Performance

- Units 1, 2 & 3 are in the Licensee Response Column of the NRC Action Matrix with no greater than Green inspection findings or performance indicators for any unit. All Cornerstone objectives have been met.
- Substantive cross-cutting issue(s): None

Key Messages or Themes

- Oconee continues to focus on licensing and design basis issues.

Items of Interest

16. Organizational issues

- Management Changes - Dhiaa Jamil succeeded Brew Barron as Chief Nuclear Officer effective February 17, 2008; Gary Peterson became Vice President, Fleet Performance Oversight and Strategy; Bruce Hamilton succeeded Gary Peterson as Vice President, McGuire Nuclear Station effective January 1, 2008; and David Baxter succeeded Bruce Hamilton as Vice President, Oconee Nuclear Station.

17. Plant equipment issues

- Tritium - Oconee has instituted a tritium groundwater monitoring program with the completion of 14 new wells installed in January of this year and initial sampling performed. No wells have had results above the Environmental Protection Agency's limit. The South Carolina Department of Health and Environmental Control sampled 6 offsite drinking wells in March and split the samples with the licensee. The licensee's results for these samples were below minimum detectable activity. The licensee is currently installing 15 geoprobe sampling points to augment their sampling effort. All monitoring wells installed by the licensee have been within the Owner Controlled Area.
- Tornado Mitigation - As a result of a 95002 supplemental inspection of two White Mitigating System tornado-related findings in 2001, it was determined that Oconee has a number of tornado-related vulnerabilities that collectively represent a deficient tornado mitigation strategy. Duke has subsequently provided its resolution to this matter by proposing the use of two redundant and largely separate tornado mitigation systems (i.e., the standby shutdown facility (SSF) and a planned protected service water (PSW) system). Duke has also informed the NRC that difficulty in meeting the Standard Review Plan TORMIS risk acceptance criteria (1.0E-6) will result in the need for more missile protection than originally thought. The current date for submitting the Tornado Mitigation license amendment request (LAR) is June 2008.
- High Energy Line Break (HELB) Mitigation - Following a 1998 self-assessment of Oconee's licensing basis for HELB events outside containment, Duke notified the NRC in January 1999 that it was initiating a project to reconstitute the design and licensing basis for HELBs outside the reactor building. The NRC staff is concerned that the analyses that were completed by Duke in 1973 for addressing postulated high energy pipe failures in the auxiliary building do not adequately consider and address the potential consequences of postulated HELB events. Submittal of Oconee's Unit 1 HELB mitigation LAR (which will include the use of existing safety systems, along with the SSF

and planned installation of the PSW system and main steam isolation valves) is currently scheduled for June 2008.

- Flood Action Plan - Using the Significance Determination Process (SDP), the staff initially evaluated a performance deficiency of a breached flood barrier to the Oconee. During a re-evaluation on licensee appeal, it was discovered that the licensee had erroneously used a significantly lower random Jocassee Dam rupture frequency in their site external flooding analysis for the Individual Plant Examination of External Events. An approach using the techniques of NUREG/CR-6823, "Handbook of Parameter Estimation for Probabilistic Risk Assessment", was used to verify this. Upon further review, it was discovered that an earlier alternate approach had underestimated dam rupture frequency published in NSAC-60, "Oconee PRA; a probabilistic risk assessment of Oconee Unit 3", a document which is referenced throughout the industry by other licensees in their flooding analyses. Consequently, an internal NRC backfit assessment/flood action plan has been implemented.
- Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS) - By a letter dated January 31, 2008 (ML080730339), Duke submitted an LAR that would allow replacement of the current analog-based RPS/ESPS with a digital computer based RPS/ESPS. The NRC staff has determined that the licensee has provided sufficient information to accept this LAR and start a comprehensive review. However, the NRC has identified several issues that were discussed with Duke in a March 18, 2008, public meeting that will present significant challenges to completing a comprehensive review of the LAR. Duke was requested to provide a schedule for submitting additional information to address those issues. During the public meeting, Duke provided milestones of its activities for the digital modification and requested that the amendments be issued by March 31, 2009, to support the Unit 1 outage (scheduled for October through December 2009). The NRC staff informed Duke that issuing the amendments by March 31, 2009, was unlikely, but based on timely responses to the information requested during this meeting and all subsequent requests for additional information, the NRC staff stated that by March 31, 2009, it would have a good indication as to whether the LAR would be found acceptable or not acceptable.

18. Recent Plant Events

- RCP Vibration/Seal Leakage - On April 28, 2008, a Special Inspection Team arrived at Oconee Nuclear Station to evaluate the Unit 1 reactor coolant pump abnormal high vibrations and seal degradation experienced during plant shutdown on April 12, 2008. Specifically, while performing plant cooldown/depressurization activities in support of the outage, the plant experienced high vibration on all three of the operating RCPs (1B2, 1B1, and 1A2), as well as experienced an approximate 5 gpm leak from the 1A2 RCP seal package and other indications of degraded stages on the 1B2 RCP seal package. At the time the 1A2 RCP seal leak occurred, the plant was on decay heat removal. However, the operating RCPs had sequentially exhibited elevated vibration levels starting near rated temperature and pressure, on through the cooldown. In addition to root cause determination, the team has been tasked to assess related operational aspects and associated corrective actions.

19. Inspection findings

- None currently greater than Green

20. Allegations

- None noteworthy

21. Safety Culture/SCWE

- None

22. **Security Issues** None

Project Status Report for the Wm States Lee III Combined License Application Review

General Information

Design: AP1000
Application Type: Subsequent COL
Location: Cherokee County, SC
Docket Date: February 25, 2008
Review Completion Date:
The review schedule was issued on April 2, 2008.

EPM Summary

Current Review Phase: Safety Review – Phase 1 – Development of preliminary safety evaluation report and requests for additional information.
Environmental Review – Phase 1 - Scoping.

Current Phase Completion Dates:

Safety Review – Phase 1 - February 9, 2009
Environmental Review – Phase 1 – September 12, 2008

Current, Critical Path and near Critical Path Task(s):

Westinghouse design certification review and the Lee seismology review.

Resource Management

Not Applicable

Project Risks

The staff identified four areas that have introduced uncertainty during development of the review schedule. These areas are: 1) incomplete recirculation screen design in the referenced design (as discussed in the AP1000 design certification amendment project status report); 2) response methods used to produce the final site ground motion; 3) the seismic source characterization of the region; and 4) potential amplification and characterization of the dynamic response of the fill material under the radwaste building, and its impact on the interface of the auxiliary and radwaste buildings during seismic activity. The staff discussed these issues in a public meeting with Duke Energy and continues to work with them as part of the COL review.

Selected News Articles

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Blue Ridge Environmental Defense League (BREDL) Press Release

April 12, 2008

PUBLIC HEARING
MAY 1, 2008 7 PM
GAFFNEY HIGH SCHOOL
149 Twin Lake Road, Gaffney, SC 29341

Stop Duke's Nukes in Cherokee County!
Join the Grassroots Campaign
Attend the Hearing

On May 1, 2008 the US Nuclear Regulatory Commission will hold its first public hearing on Duke Power's proposed nuclear plants. The public will have an opportunity to speak.

What's Wrong With Nuclear Power?

Harmful radioactive pollution is released into the air and water from nuclear power plants on a routine basis. Also, highly toxic radioactive waste is stored on site in pools of water.

Nuclear power is expensive. Duke is reluctant to publish financial data, but experts say that nuclear reactors today cost between 6 and 9 billion dollars each to construct. Duke plans two.

Duke's nukes would consume 4 times as much water as all public and industrial users in Cherokee County combined (Duke License Application Environmental Report Section 2.3.2).

Earthquake risks. South Carolina averages 15 to 20 earthquakes annually. One of the largest known earthquakes in eastern North America occurred near Charleston. SC Emergency Management says: "Where earthquakes have occurred in the past, they will happen again."

Nuclear Power Affects Human Health

Children living near nuclear power plants suffer higher levels of birth defects, cancer and early death. A study of medical records found that **infant death rates near five U.S. nuclear plants increased within two years after the plants opened. The study also found that infant deaths decreased 15-20% soon after the reactors closed.** And the decreases in cancer and birth defects continued for 7 years after plant closure. (*Environmental Epidemiology and Toxicology*, 2002, Radiation and Public Health Project)

False Advertising

The Better Business Bureau said ads calling nuclear energy "clean" were wrong because nuclear plants cause thermal water pollution and nuclear fuel production causes air pollution. BBB told the nuclear industry to stop making such claims.

The License Process

On December 13, 2007 Duke Energy applied to the US Nuclear Regulatory Commission for a license to build and operate two nuclear plants on the Broad River near Gaffney, South Carolina. The application is for two Westinghouse AP1000 Pressurized Water Reactors designated Lee Nuclear Station Units 1 & 2. The NRC plans to issue a Draft Environmental Impact Statement in March 2009 and a Final Environmental Impact Statement in 2010. The public will have opportunities to comment on these documents.

Blue Ridge Environmental Defense League
PO Box 88 Glendale Springs, North Carolina 28629 (336) 982-2691
BREDL@skybest.com http://www.BREDL.org

Thursday, March 13, 2008

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DUKE ENERGY REVISED ORGANIZATION

- Dhiaa Jamil, Group Exec. & Chief Nuclear Officer
  - Ronald Jones, Sr Vice President Nuclear Operations
  - Gary Peterson, Vice President Nuclear Fleet Performance
  - Bryan Dolan, Vice President Nuclear Projects
  - Lisa Vaughn, Assoc. Gen. Counsel & Managing Attorney
  - Tom Geer, Vice President Nuclear Engineering
  - Jeana Grisdale, Vice President Nuclear HR
  - Terry Dimmery, General Manager Nuc Business Planning
  - Dave Jones, Director Nuc Policy & Strategic Issues
  - Cheryl Peed, Employee Concerns Program

- Ron Jones, Sr Vice President Nuclear Operations
  - Dave Baxter, Vice President Oconee Nuclear Station
  - Bruce Hamilton, Vice President McGuire Nuclear Station
  - Jim Morris, Vice President Catawba Nuclear Station
  - Tom Harrall, Vice President Plant Support
  - Dan McRainey, Vice President Major Projects
  - Jim Fisicaro, Director Nuclear Regulatory Relations

Overview of Duke Energy

Duke Energy, one of the largest power companies in the United States, supplies and delivers electricity to approximately 3.9 million customers in the Carolinas and the Midwest. The company also distributes natural gas in Ohio and Kentucky, generates electricity in Latin America, and is a joint-venture partner in a U.S. real estate company. Headquartered in Charlotte, N.C., Duke Energy is a Fortune 500 company traded on the New York Stock Exchange under the symbol DUK.

Duke Energy applied for a Combined Operating License (S-COLA) to construct and operate two AP 1000 PWRs named the William States Lee after their former Chairman. The plants are proposed to be located in Cherokee County, South Carolina.

Duke Energy also operates the Catawba, McGuire and Oconee nuclear stations.

BIOGRAPHIES

Dhiaa M. Jamil Group Executive and Chief Nuclear Officer

Dhiaa Jamil is group executive and chief nuclear officer for Duke Energy. He is responsible for the safe and efficient operation of the company's three nuclear generating stations - Catawba, McGuire and Oconee nuclear stations. He was named to his current position in January 2008.

Jamil has more than 25 years of experience in the energy industry.

Most recently, Jamil served as senior vice president of nuclear support. He led the organization responsible for plant support, major projects and fuel management for Duke Energy's nuclear fleet. In addition, he was responsible for regulatory support, nuclear oversight and safety analysis functions.

He joined Duke Power in 1981 as a design engineer in the design engineering department. After a series of promotions, he was named electrical systems engineering supervisor of Oconee Nuclear Station in 1989 and electrical systems engineering manager in 1994. He was named maintenance superintendent of McGuire Nuclear Station in 1997; station manager in 1999; and site vice president of McGuire Nuclear Station in 2002. In that role, Jamil was responsible for all aspects of the safe and efficient operation of the nuclear site. He was appointed site vice president of Catawba Nuclear Station in 2003.

Jamil received a Bachelor of Science degree in electrical engineering from the University of North Carolina at Charlotte.

He is a registered professional engineer in North Carolina and South Carolina. He has completed the Institute of Nuclear Power Operations' (INPO) senior nuclear plant management course and received Duke Energy's technical nuclear certification. He has served as a senior member of the Institute of Electrical & Electronics Engineers (IEEE) and has completed a three-year assignment as a member of the Council of the National Academy for Nuclear Training. He is a former member of Dominion Energy

Management Safety Review Advisory Committee, TVA Nuclear Safety Review Board and Pacific Gas & Electric Nuclear Safety Oversight Committee. He also served on the board of directors of the York County, S.C., Chamber of Commerce.

Jamil is currently a member of the board of directors of the Charlotte Research Institute and serves on an advisory board for the School of Engineering at the University of North Carolina at Charlotte. He is a member of the INPO Executive Advisory Group, the Nuclear Energy Institute (NEI) New Plant Oversight Committee and the NEI Nuclear Strategic Issues Advisory Committee Steering Group.

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April 18, 2008

James J. Fisicaro
Director – Regulatory Relations Nuclear Generation

Jim Fisicaro is director of regulatory relations nuclear generation for Duke Energy. He is responsible for coordinating the interface with the Nuclear Regulatory Commission nuclear reactor regulation and the Nuclear Energy Institute (NEI). He also serves on the Oconee Nuclear Station safety review board.

Most recently, Fisicaro served as general manager of nuclear assurance in nuclear generation for Duke Power. He was responsible for corporate licensing, corporate assessment and audit functions, operating experience, industry interface, monitoring and tracking industry issues, the nuclear safety review board, quality assurance and quality control activities, and the in-service inspection program.

Fisicaro joined Duke Power in 1997. He was named to his current position in April 2006. Prior to joining the company, he was director of nuclear safety at Entergy.

Fisicaro is past chairman of the Nebraska Section of the American Society of Mechanical Engineers, Region IV Commitment Tracking Utility Group, NEI – Licensing Action Task Force, and chairman – National Directors of Oversight. He has served as chairman of several nuclear safety review boards and as a member of several nuclear industry task forces. He also served as a loaned executive and management sponsor for United Way.

(b)(6) Fisicaro graduated from Arkansas Technical University (b)(6)

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Oconee Nuclear Station
External Flood
NRR Meeting
Rockville, MD
December 4, 2008

D 25

Duke Attendees

- Rich Freudenberger, ONS Safety Assurance Manager
- Graham Davenport, ONS Regulatory Compliance Manager
- Steve Nader, Corporate PRA Manager
- Tim Brown, ONS Project Manager
- Lee Kanipe, PRA Senior Engineer
- Ray McCoy, ONS Senior Engineer
- Ed Luttrell, DTA Principal Engineer

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Agenda

- Opening Remarks
- Description of the Jocassee Project
- Current Oconee Flood Licensing Basis
- Jocassee Failure Modes and Analyses (Separate Presentation)
- Inundation Analyses
- Seismic and Civil / Structural Analyses
- Future Actions
- Regulatory Commitments
- Closing Remarks

~~Withhold from public disclosure under 10 CFR 2.390~~

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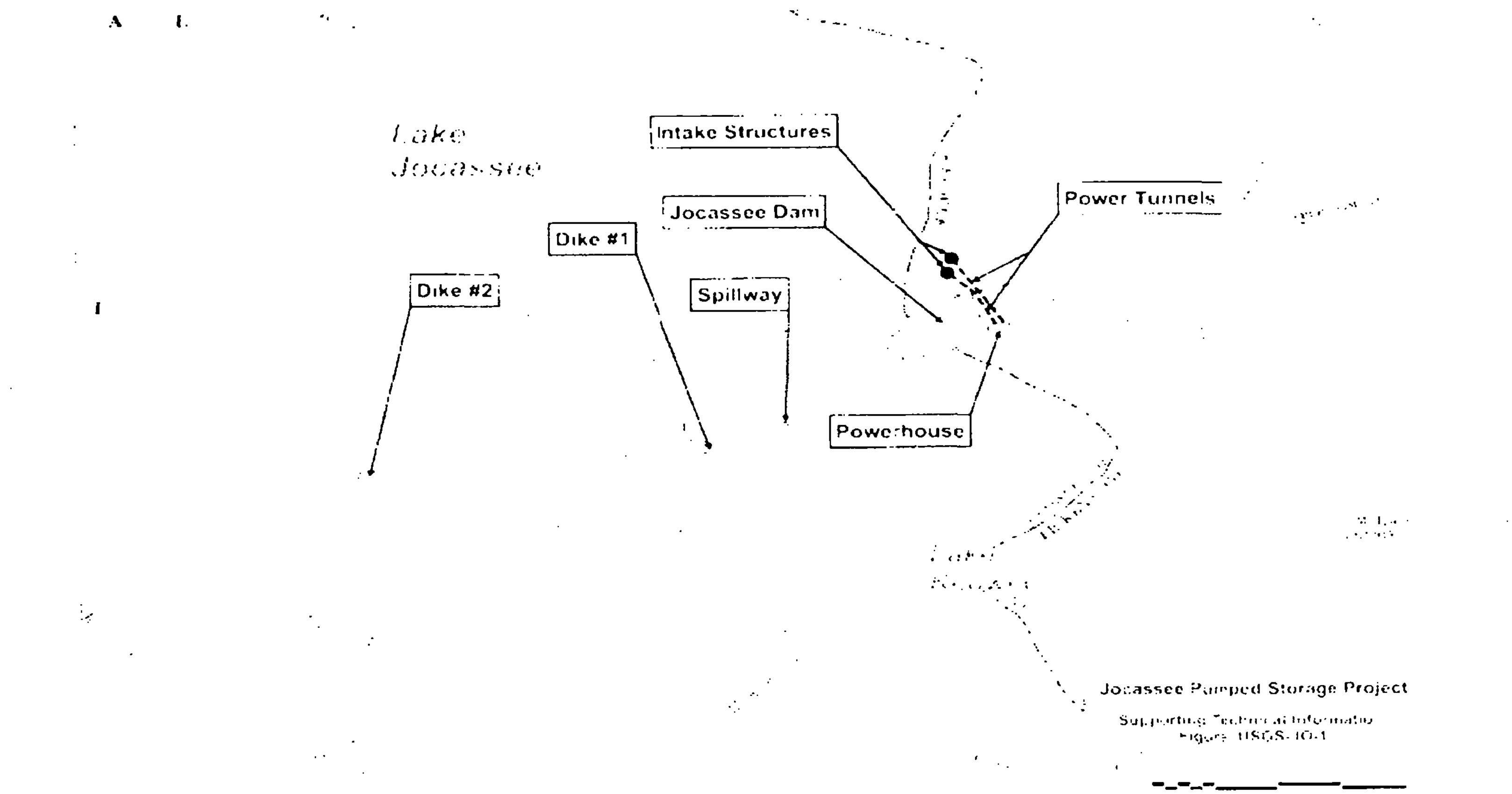
Jocassee Description



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Jocassee Description

- Full pond elevation 1110 ft.msl
- Maximum licensed drawdown elevation 1080 ft.msl
- Main Dam design: Earthen core contained by rockfill shells, crest elevation 1125 ft.msl, height- 385 feet.
- Production Details: 4 turbines providing approximately 610 MW
- Minimum intake elevation 1043 ft.msl
- Spillway independent of main dam, constructed in a bedrock excavation. Spillway contains two flood gates. The elevation of the top of the flood gates is 1110 ft.msl

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Jocassee Description

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Jocassee Description

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Jocassee Description

Withheld from public disclosure
under 10 CFR 2.390

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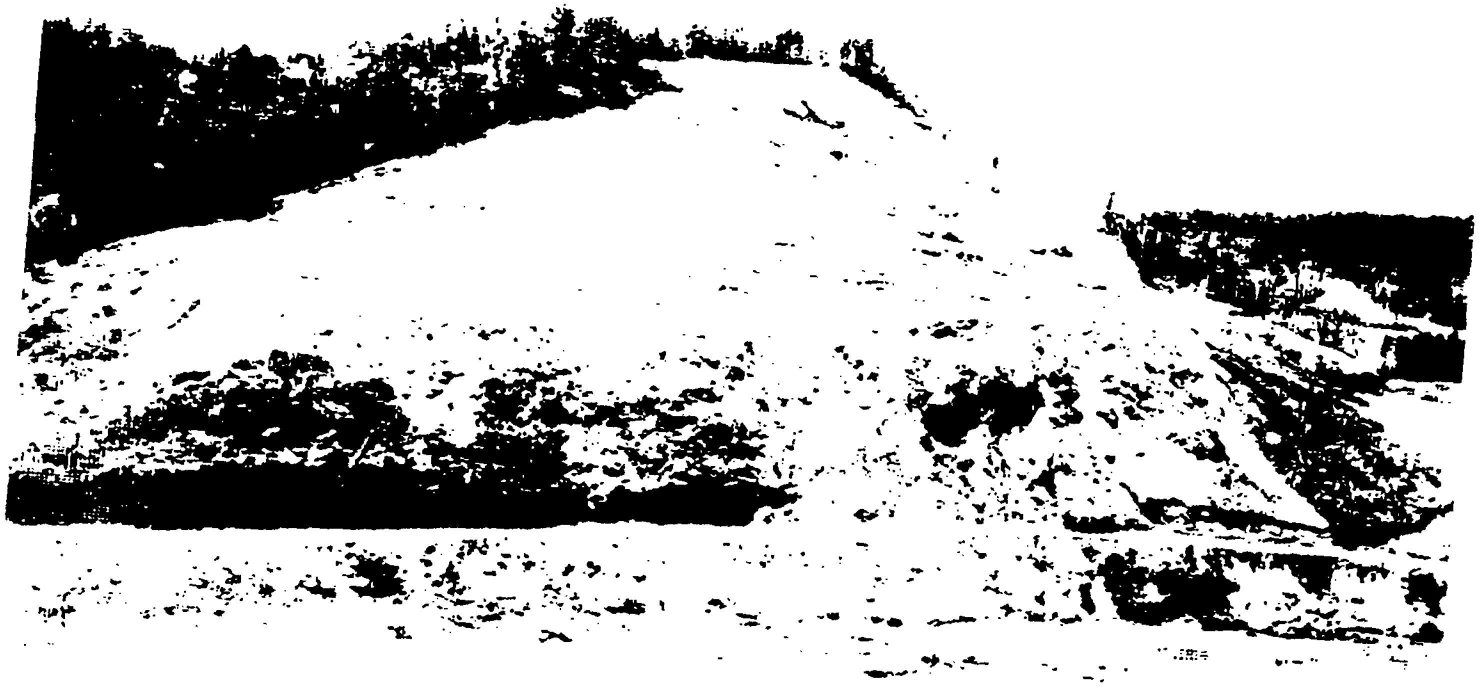
Jocassee Description



West (Right) Abutment

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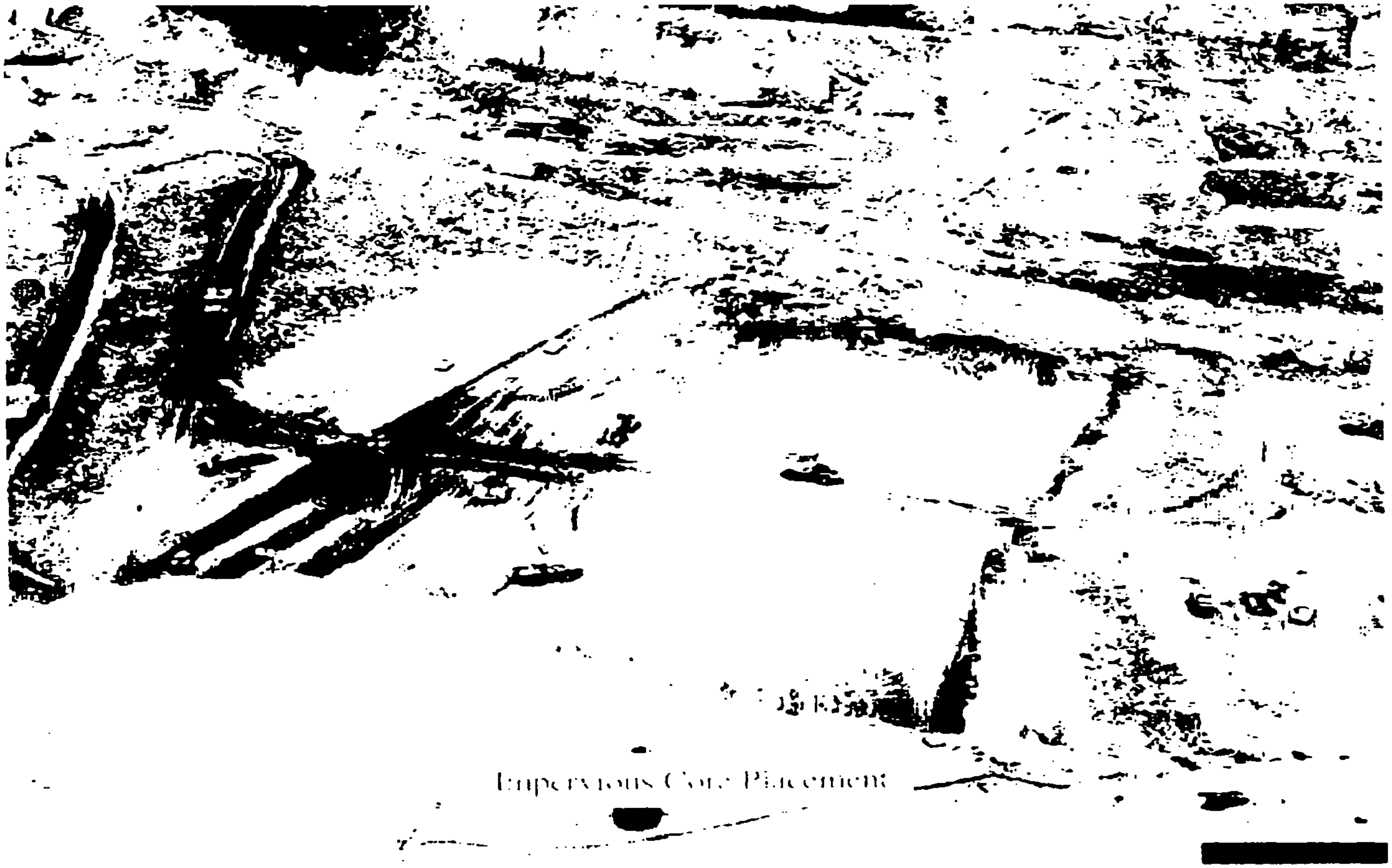
Jocassee Description



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Jocassee Description

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Jocassee Description

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Jocassee Description

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Jocassee Description

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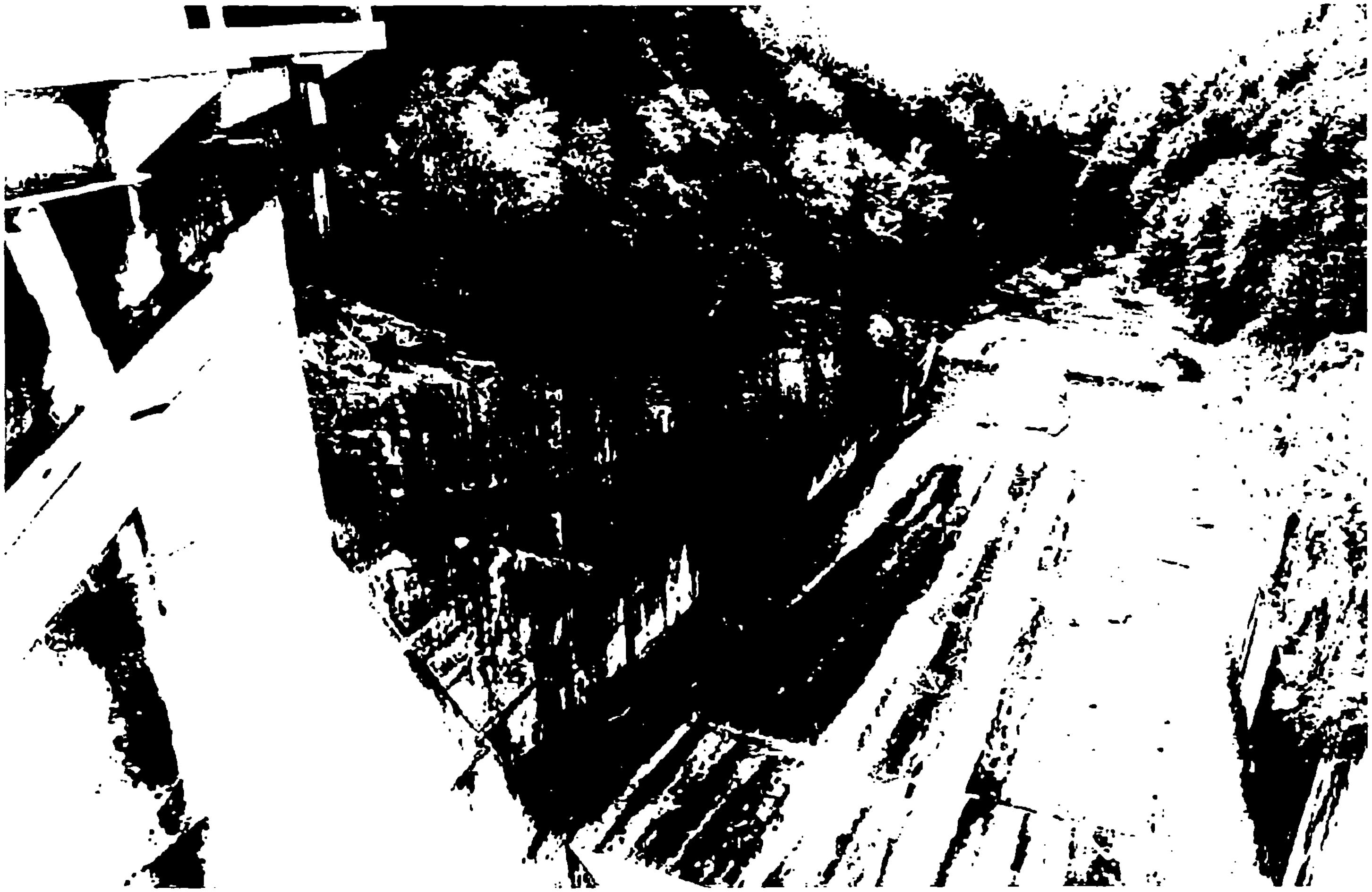
Jocassee Description



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Current Flood Licensing Basis

- The Oconee flood CLB is based on a PMP event directly applicable to the site.
- The SSF is credited to mitigate the effects of the failure of a CCW expansion joint in the Turbine Building.
- Since Jocassee is seismically designed and was constructed to high standards, upstream dam failures were not considered in determining external flood threats to the Oconee site.
- Current SSF flood protection is provided as a PRA enhancement as stated in UFSAR 9.6.3.1.
- Random or "sunny day" dam failures are not addressed in the Oconee CLB.

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Inundation Analyses

- Status of HEC-RAS Analysis
  - The HEC-RAS model will be a 'portion' of the 1992 DAMBRK Inundation model.
  - The new model will be from Jocassee Dam to 'flat water' in Lake Hartwell sufficiently below the Keowee Dam to where the sensitivity on the Keowee Tailrace is insignificant.
  - Preliminary runs are currently being assessed for reasonableness and accuracy.
  - Preliminary results expected by Dec 12th.

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Inundation Analyses

- Status of HEC-RAS Analysis / cont.
  - The HEC-RAS model will have more cross sections between Jocassee and Keowee Dams than the original model, giving more definition.
  - The HEC-RAS model will have more cross sections between the Keowee Dam and the Control Point than the original model, giving more downstream detail.
  - Large tributaries along Keowee and the Little River arm of Lake Keowee will be modeled as storage areas.

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Inundation Analyses

- Status of HEC-RAS Analysis / cont.
  - The model will have the same breach sizes as the 1992 study for both Jocassee and Keowee Dams.
  - The HEC-RAS model will assume Keowee Dam fails due to overtopping.
  - The HEC-RAS model will be a 'Sunny Day Break' of Jocassee Dam only so as to compare the model sensitivity conversion.
  - The completed model will be a useful tool in assessing the sensitivity of various input parameters.

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Inundation Analysis

- 1D vs. 2D Modeling Approach
  - The HEC-RAS 1-D modeling will handle the unsteady flow necessary for this hydrodynamic modeling.
  - 1-D modeling is typically used for river channels, where the predominant direction of flow is parallel to the boundaries.
  - 2-D modeling is used more for floodplains or complex flow situations, where the boundaries only dictate the flow patterns in the immediate vicinity of the boundaries.
  - 1-D modeling is recognized as the appropriate standard for modeling large breach discharges such as being postulated for the Jocassee Dam breach.

Inundation Analysis

- 1D vs. 2D Modeling Approach / cont.
  - 1-D model uses one dimensional energy equations
  - 1-D models dissipate energy by friction and the expansion / contraction of the channel.
  - A horizontal water surface is assumed across the entire cross-section.
  - 1-D modeling is most appropriate for the majority of the Jocassee-Keowee model under review. 1-D models have been widely used to model flood flows for large and complex river systems.

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Inundation Analysis

- 1D vs. 2D Modeling Approach / cont.
  - 2-D models are more appropriate when off-channel flooding is the focus, and obstacles and obstructions impede the flow.
  - 2-D models can be integrated with the 1-D models to more accurately represent the case where a river breaches a levee, or the river embankment (or complex flood plains).
  - 2-D modeling may be appropriate for the Keowee Tailrace area where lateral flows occur and off-channel water heights are the focus.

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Inundation Analysis

- Assessment of Bounding Analyses
  - The Potential Failure Modes Analysis (2004) and the Risk Study in Progress will determine the most probable failure modes for the dam in order to characterize appropriate input parameters for an Inundation study comparison.
  - Cascading dam failure of Keowee was assumed following the 'sunny-day' breach of Jocassee.

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Inundation Analysis

- Input Parameters
  - Breach Size
    - Breach size used equivalent to those (Jocassee and Keowee) assumed in the 1992 study:
      - Jocassee average breach width 575 feet, or 1.8 times the height of the dam.
      - Keowee average breach width 645 feet, or 4.4 times the height of the dam.
    - Alternate breach size, equivalent to that assumed in 1983 work:
      - Jocassee average breach width 455 feet, or 1.4 times the height of the dam.

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Inundation Analysis

- Input Parameters
  - Time to Failure
    - Jocassee: 4 hours used.
      - Froehlich equations suggest a value of 3+ hours
      - MacDonald & Langridge-Monopolis suggest a value of 6.4 hours
    - Therefore, the use of 4 hours appears reasonable.
    - Keowee: 2 hours used.
      - The overtopping failure time was varied between 1 and 2 hours to assess downstream effects. They were insignificant at about 3 miles downstream, so 2 hours was used making the math models more stable.

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Inundation Analysis

- Input Parameters
  - PMF is not being considered at this time due to the ability of the Jocassee project to absorb and pass a PMF.

Seismic & Civil / Structural Analyses

- Seismic Capacity
  - Duke submitted the revised Jocassee seismic fragility evaluation to the NRC by letter dated 2/5/07.
  - The evaluation was performed by Applied Research & Engineering Sciences (ARES) Corp., formerly EQE, a respected consulting firm in the area of seismic fragility.
  - The combination of the updated seismic fragility with the seismic hazard curve results in a negligible risk contribution from seismic events.
  - The NRC has previously agreed with the negligible risk characterization in a letter dated 11/20/07.

Seismic & Civil / Structural Analyses

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- Seismic Capacity / cont.
  - The Jocassee main dam is designed to a .12 g horizontal ground acceleration
  - Jocassee Dam included in seismic model of Oconee PRA.
  - PRA seismic capacity with regard to failure (based on ARES Report):
  - Median centered fragility value for dam failure is 1.640 g.
  - Equivalent HCLPF value (95% confidence) 0.305 g.

Seismic & Civil / Structural Analyses

- Discussion of Seepage from 2004 to Present
  - There are a total of 24 seepage monitoring stations.
  - 11 of the total are located on the West Abutment.
  - 7 of the total are located on the East Abutment.
  - 3 of the total are located downstream of the Powerhouse.
  - 2 of the total are located downstream of each saddle dike respectively.
  - 1 of the total is located at the toe of the Main Dam .
  - 15 of the monitoring stations currently have no active seepage flow.
  - Seepage monitored both quantitatively and qualitatively bi-weekly.

Seismic & Civil / Structural Analyses

- Discussion of Seepage from 2004 to Present / cont.
  - Of the remaining 9 having active seepage flow, 3 are located on the East Abutment, 5 are located on the West Abutment, 1 is located downstream of Saddle Dike 1.
  - The Parshall Flume collects all seepage from the West Abutment.
  - East Abutment seepage ranges from 1 to 20 gpm
  - West Abutment seepage, as collected at the Parshall Flume, ranges from 450 to 900 gpm
  - Seepage downstream of Saddle Dike 1 ranges from 2 to 30 gpm
  - Monitored seepage generally follows the reservoir elevation
  - Seepage monitoring data is reviewed annually by FERC.

Seismic & Civil / Structural Analyses

- Settlement of Dam
  - The crest of the main dam (elev. 1125+0 msl.) contains nine (9) settlement monuments.
  - There are five (5) settlement monuments @ the elev. 925+0 msl bench on the downstream slope of the dam.
  - There are three (3) settlement monuments at the toe of the dam @ elev. 810+0 msl.
  - Settlement monuments are monitored for both vertical and horizontal displacements.
  - Settlement monuments are surveyed annually.

Seismic & Civil / Structural Analyses

- Settlement of Dam (Since baseline made in 1992):

Location	Displacement Range (in.)	
	Horizontal (downstream)	Vertical (down)
Crest	.3 to 2.5	.5 to 2.0
Bench @ Elev. 925.0 msl	.2 to .4	.24 to .5
Toe	.024 to .12	.24 to .3

Seismic & Civil / Structural Analyses

- Settlement of Dam / cont.
  - Magnitude of horizontal and vertical displacements are acceptable, given the size and weight of the dam.
  - Magnitude of horizontal and vertical displacements within the range reported for similar rock filled dams.
  - Displacement data reported annually to FERC.

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Seismic & Civil / Structural Analyses

- Condition of Embankment Shells & Potential Soil Liquefaction
  - Liquefaction potential dependent on material type, method of placement, compaction, and seismic demand.
  - Placement and compaction of the core of the main dam materials was closely controlled during construction by the use of Proctor tests.
  - Core materials have sufficient densification to preclude initiation of liquefaction during a seismic event.

Seismic & Civil / Structural Analyses

- Condition of Embankment Shells & Potential Soil Liquefaction / cont.
  - The shells are composed of random rock and silty sand.
  - Matrix of random rock limits liquefaction potential to small isolated zones that would not effect the overall stability of the dam
  - Jocassee designed to a .12g horizontal ground acceleration.
  - Liquefaction is not an issue, given the construction practices and the magnitude of the design seismic ground acceleration.

Seismic & Civil / Structural Analyses

- Discussion of Dam Construction and Soil Compaction
  - Construction of the Dam was controlled by drawings and specification. This included excavation, preparation, materials, and construction practice.
  - Design and Construction reviewed by independent board of consultants.
  - Construction practice was consistent with the current state of practice for similar structures.

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Future Actions

- Evaluate flooding potential with HEC-RAS software:
  - Objective: Provide more realistic flooding assessment using more modern software for comparison with previous DAMBRK model results.
- Risk Assessment Study:
  - Objective: Provide risk assessment of potential dam failure modes and resulting flooding. Assign probability to each failure mode / flooding pair.

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Regulatory Commitments

Commitment	Completion Date
Perform flooding studies using HEC-RAS for comparison with previous DAMBRK models.	12/2008
Create interim guidance to address mitigation of postulated flood events that could render the SSF inoperable.	2/2009
Implement short term modifications to extend the height of the existing SSF flood walls to 803 ft msl.	2/2009
Complete Risk Assessment Study by RAC and New Flood Study using HEC-RAS, by DTA.	2/2010

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Closing Remarks

- Jocassee is a well designed, well constructed, well maintained, and federally administered project.
- Failure of the Jocassee dam is not considered a part of the Oconee CLB.
- Duke has completed exploratory flood analyses that demonstrate the importance of the dam failure breach size as an input for the determination of inundation levels. Additional analyses, underway, will validate these results.
- Duke has committed to increase the height of the current SSF walls to provide additional safety margin against external flooding.
- Duke has commissioned an independent risk study to determine appropriate dam failure probabilities and resulting inundation levels.
- Duke is prepared to evaluate engineered solutions as appropriate once realistic and reasonable design inputs are determined.

Dam Failure Rate Analysis

Assumptions

- Infant mortality (<5 years) excluded

    Jocassee is 30+ years old

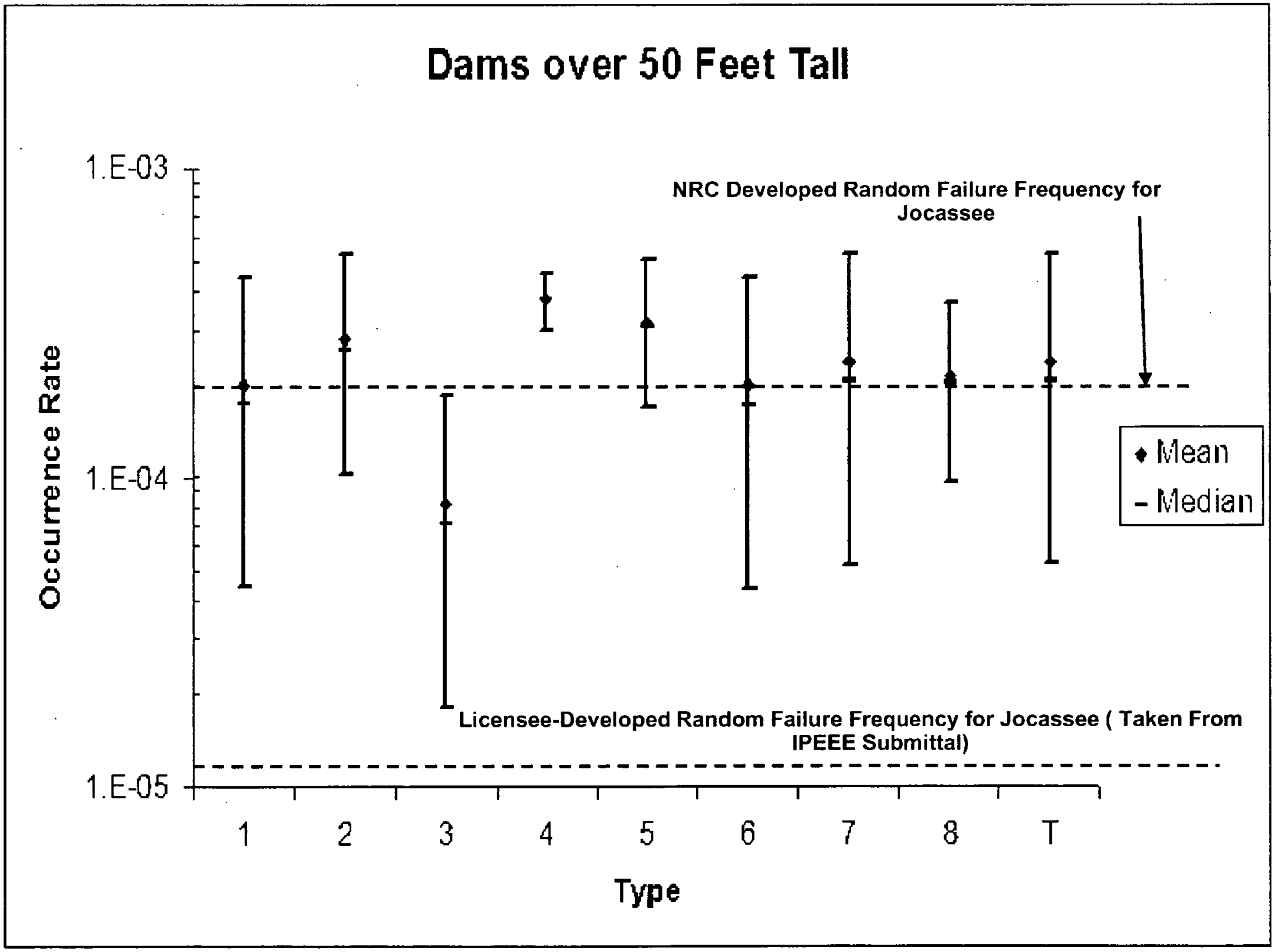
- Elderly (<1940) age and construction excluded

    Jocassee is of modern design

- Small projects (<50 ft) excluded

    Jocassee is engineered as a large well funded project

1	Buttress Dams Over 50 Feet High
2	Arch Dams Over 50 Feet High
3	Concrete Dams Over 50 Feet High
4	Earth Dams Over 50 Feet High
5	Gravity Dams Over 50 Feet High
6	Masonry Dams Over 50 Feet High
7	Multi-Arch Dams Over 50 Feet High
8	Rockfill Dams Over 50 feet high
T	Total



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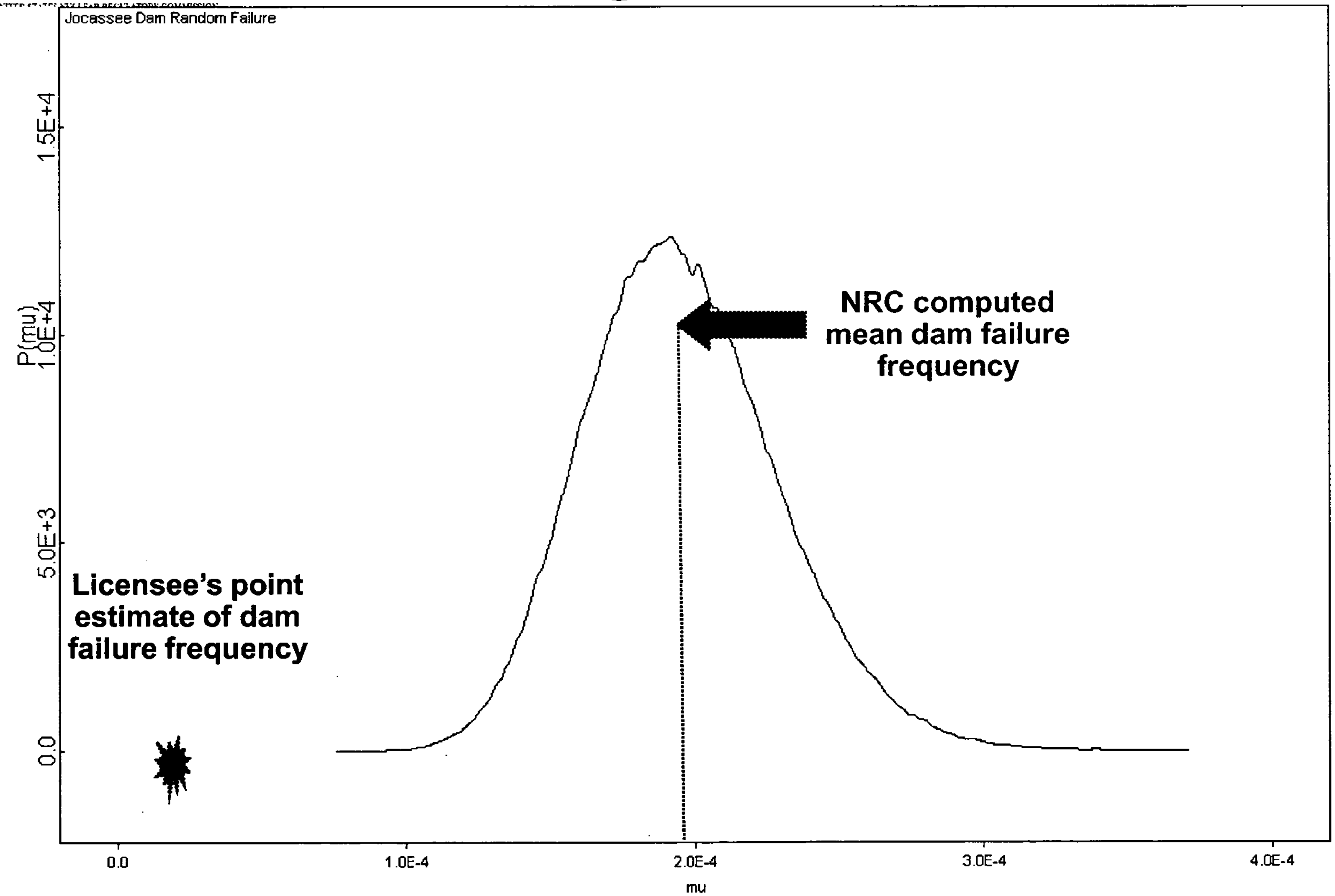

Jocassee Dam Random Failure
1.5E+4
1.0E+4
P(mu)
5.0E+3
0.0
0.0
1.0E-4
2.0E-4
3.0E-4
4.0E-4
mu
NRC computed mean dam failure frequency
Licensee's point estimate of dam failure frequency

Duke Letter Response

- There have been overtopping control system failures as seen with the Taum Sauk Dam rupture in Missouri.
- Was soil liquefaction during a seismic event considered?
- In order to operate the spillway effectively, the gates must be fully open AND three-of-four turbines must be operable.
- A PFMA study is not a PRA study. NRC feels that use of this broader study does not support the parsing (subdivide) of data since it does not account for uncertainties in limited data.
- Duke cites that Jocassee Dam cannot experience any failures based on design margins, construction, inspections, and operation. The NRC staff is not aware of information that makes Jocassee Dam unique compared to other dams.
- In considering PMP, Frenchman and Skagway would be designed to the same rainfall margin as Jocassee.
- NRC only considered dams of height greater than 50 feet. The statement that failures involving embankment slides should be excluded does not agree with the data which shows an increase of embankment seepage and settling of the dam. Although not likely, these failure modes are still credible for Jocassee.

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

BRIEFING BOOK

FOR

COMMISSIONER PETER B. LYONS

OCONEE NUCLEAR STATION

FEBRUARY 3, 2009

On-Site Visit by Commissioner Lyons

CONTENTS

Agenda for Commissioner Peter Lyons' Visit to Oconee Nuclear Station - February 3, 2009

Feb 2, 2009

5:00 p.m.	Depart Washington Dulles Airport on United Airlines Flight 8071
6:31 p.m.	Arrive at Greenville-Spartanburg Airport
7:00 p.m.	Leave Greenville-Spartanburg via Budget Rent A Car
8:00 p.m.	Arrive at Hampton Inn, Clemson, SC

Feb 3, 2009

8:00 a.m.	Travel to Oconee Nuclear Station via rental car
8:30 a.m.	Arrive at Oconee Nuclear Station (Oconee Office Complex Bldg 8032) Meet with NRC resident inspector and branch chief
9:00 a.m.	Meet with licensee for discussions involving: • National Fire Protection Association (NFPA)-805 Transition • Tornado/High Energy Line Break (HELB) • Protected Service Water (PSW)/Natural Phenomenon Barrier System
9:30 a.m.	Plant tour with plant management, NRC branch chief, resident inspector, and the Commissioner's Technical Assistant (TA) • Standby Shutdown Facility (SSF) • Unit 3 Control Room North Wall • Reactor Protective System/Engineered Safeguards Protective System (RPS/ESPS) Digital Upgrade discussion in the control room
11:30 a.m.	Working lunch with licensee managers • Jocassee Dam Pre-brief
12:15 p.m.	Depart for World of Energy visit
1:00 p.m.	Depart from World of Energy and travel to dam
1:30 p.m.	Tour dam
4:00 p.m.	Return to site
4:30 p.m.	Depart Oconee Nuclear Station and travel to Greenville-Spartanburg Airport via rental car
6:59 p.m.	Depart Greenville-Spartanburg Airport on United Airlines Flight 8070
8:23 p.m.	Arrive Washington Dulles Airport

Executive Summary

Purpose of the visit/meeting

- Tour Oconee Nuclear Station and Jocassee Dam
- Meet with plant management, NRC branch chief, and resident inspection staff

Issues to be addressed (See TAB 6)

- Current plant issues and planned plant modifications

Persons to meet

Region II personnel (See TAB 9)

- Eric Riggs, Resident Inspector
- Jonathan Bartley, Chief, Reactor Projects Branch 1

Oconee personnel (See TAB 8)

- David Baxter, Oconee Site Vice-President
- Preston Gillespie, Oconee Station Manager
- Michael Glover, General Manager of Oconee Nuclear Plant Projects
- Scott Batson, Oconee Engineering Manager
- Rich Freudenberger, Oconee Safety Assurance Manager

Activities on site

- Tour facility with plant management, NRC branch chief, resident inspector, and Commissioner's TA
- Tour Jocassee Dam

Message to be communicated by the Commissioner

- Important to keep Tornado/HELB modifications on track
- Important to focus on Nuclear Performance Plan

Licensee's briefing topics for the Commissioner

- NFPA 805 Transition
- Tornado/HELB
- PSW/Natural Phenomenon Barrier System
- SSF
- Unit 3 Control Room North Wall
- RPS/ESPS Digital upgrade

Licensee Ownership Information

Duke Energy Carolinas owns and operates the two-unit McGuire and the three-unit Oconee nuclear stations. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station.

Recent Oconee Management Changes (See TAB 7)

Dhiaa Jamil succeeded Brew Barron as Chief Nuclear Officer effective February 17, 2008; Gary Peterson became Vice President, Fleet Performance Oversight and Strategy; Bruce Hamilton succeeded Gary Peterson as Vice President, McGuire Nuclear Station effective January 1, 2008; and David Baxter succeeded Bruce Hamilton as Vice President, Oconee Nuclear Station. Effective October 2008, Preston Gillespie left his role as Operations Superintendent at Catawba to become the Oconee Station Manager.

ROP Assessment - Significant ROP Inspection Findings (See TAB 5)

Plant performance for 2008 was within the Licensee Response Column of the NRC's Action Matrix for Units 1, 2 and 3. All Performance Indicators (PIs) and findings are **GREEN**.

Note: A Regulatory Conference was held with Duke on January 22, 2009, for the Unit 1 loss of inventory event. A caucus was held on January 28, 2008, to finalize the significance determination. [PREDECISIONAL INFORMATION - Preliminary results, including addressing the licensee's comments on the risk, are that the finding will be **WHITE**. This would put Unit 1 in the Regulatory Response Column.]

Potential Discussion Topics (See TAB 6)

Flood Action Plan
The NRC is evaluating an "inadequate protection" issue related to a past finding involving a breached flood barrier of the Oconee safe shutdown facility (SSF). NRR is assessing the options regarding a final response to the licensee's 50.54(f) response.

Tornado Mitigation
As a result of a 95002 supplemental inspection of two White Mitigating System tornado-related findings in 2001, it was determined that Oconee has a number of tornado-related vulnerabilities that collectively represent a deficient tornado mitigation strategy.

HELB Mitigation
Following a 1998 self-assessment of Oconee's licensing basis for HELB events outside containment, Duke notified the NRC in January 1999 that it was initiating a project to reconstitute the design and licensing basis for HELBs outside the reactor building.

NFPA 805 Transition
Oconee is one of two pilot plants that are in the process of transitioning to NFPA 805 for fire protection. NRR is planning an on-site review, in February 2009, of Oconee's license amendment request (LAR) submittal.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)
Duke submitted a LAR that would allow replacement of the current analog-based RPS/ESPS with a digital computer based RPS/ESPS. Implementation will begin in Fall 2010 or Spring 2011 following development of modification packages.

William States Lee III Nuclear Station Combined Operating License (COL) Application
Duke Energy submitted a 10 CFR 52 application for a combined operating licensee to the NRC on December 13, 2007, which was docketed on February 25, 2008.

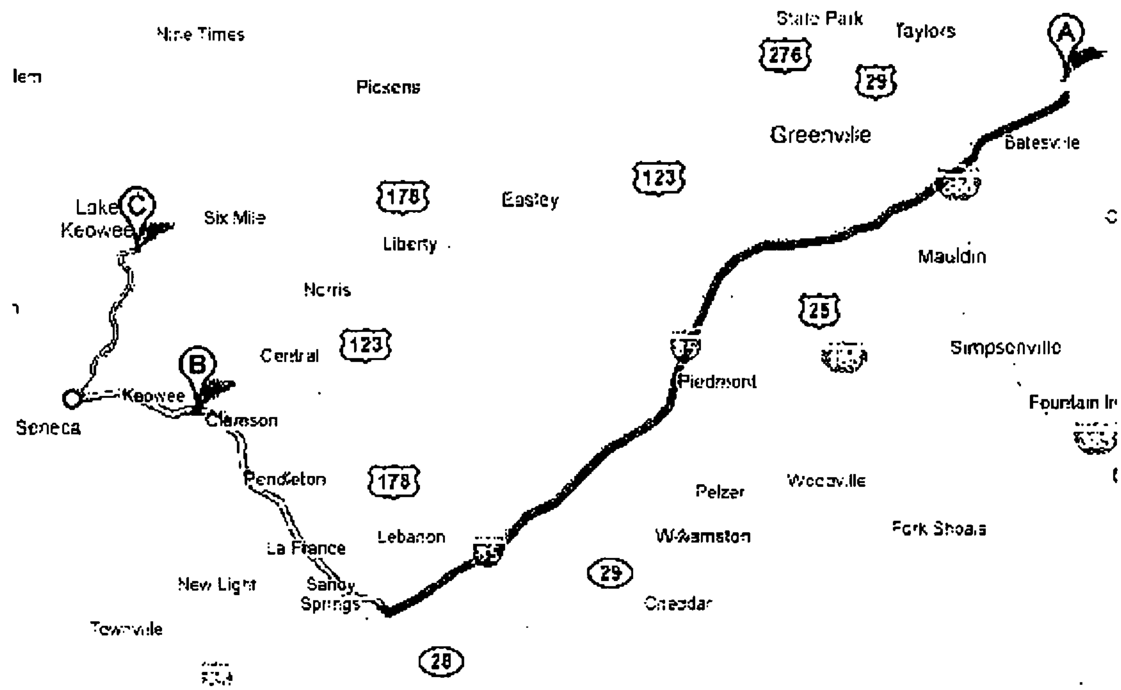
Unit 1 Loss of Inventory Event
A Regulatory Conference was held on January 22, 2009. The post-conference caucus was held on January 28, 2008, to finalize the significance determination. The final significance determination is pending. [PREDICISIONAL INFORMATION: Preliminary results, including addressing the licensee's comments on the risk presented at the Regulatory Conference, are that the finding will be **WHITE**.]

Unit 3 Reactor Trip
At 0834 hours on November 7, 2008, a Unit 3 reactor trip occurred. The licensee's investigation determined that the trip was a result of a simultaneous shut down of the control rod drive (CRD) digital primary processors caused by an erroneous time signal from the satellite clock repeater for Unit 3.

Approval for Additional Resident Inspector
A temporary third resident has been authorized for the Oconee site due to the large number of planned permanent plant modifications.

INPO Rating and Nuclear Performance Plan
A two week INPO E&A was conducted during July 2008 with the final numerical rating being an INPO 2. As a result, the licensee has developed a recovery plan which outlines initiatives and areas of responsibility to improve overall plant performance.

Facility Location Map and Directions



A - Greenville-Spartanburg International Airport (Aviation Dr/Jetport Rd) **to**
B - Hampton Inn Clemson (851 Tiger Boulevard, Clemson, SC 29631)

50.2 mi - about 55 mins

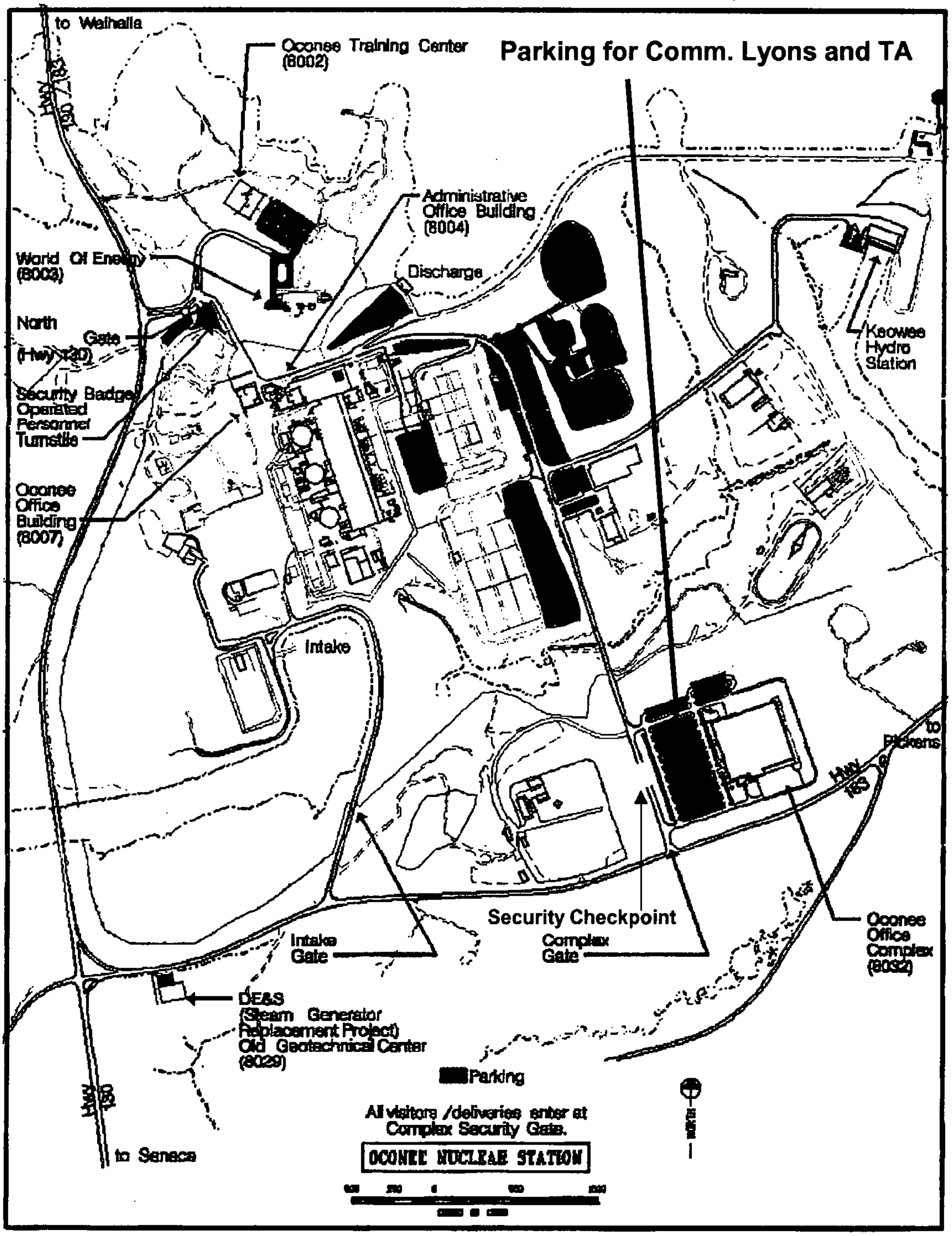
- Head southeast on Aviation Dr/Jetport Rd (*0.5 mi*)
- Merge onto I-85 S via the ramp to Greenville (*37.2 mi*)
- Take exit 19B for State Hwy 28 W/US-76 W toward Clemson (*0.4 mi*)
- Merge onto Clemson Blvd/SC-28/US-76
- Continue to follow SC-28 (*10.9 mi*)
- Turn left at SC-28/Tiger Blvd/US-123/US-76
- Destination will be on the right (*1.2 mi*)

B - Hampton Inn Clemson (851 Tiger Boulevard, Clemson, SC 29631) **to**
C - Oconee Nuclear Station (7800 Rochester Hwy, Seneca, SC 29672)

13.2 mi - about 22 mins

- Head west on SC-28/Tiger Blvd/US-123/US-76
- Continue to follow SC-28/US-123/US-76 (*5.4 mi*)
- Turn right at SC-130 (*7.1 mi*)
- Turn right at SC-183 (*0.7 mi*)
- Turn left into plant entrance and right into Oconee Office Complex parking lot
- Park in first available parking spot. Licensee will provide transportation through security checkpoint and to personnel access portal. NRC Branch Chief and Resident Inspector will greet you at the portal.

Oconee Site Map



Facility Data

Utility: Duke Energy Carolinas, LLC
Location: 8 miles northeast of Seneca, SC
County: Oconee County, SC

	UNIT 1	UNIT 2	UNIT 3
Docket Nos.	50-269	50-270	50-287
License Nos.	DPR-38	DPR-47	DPR-55
Full Power License	02/06/1973	10/06/1973	07/19/1974
Commercial Operation	07/15/1973	09/09/1974	12/16/1974
OL Expiration Date	02/06/2033	10/06/2033	07/19/2034

PLANT CHARACTERISTICS	All Units
Reactor Type	PWR
Containment Type	Dry Ambient
Power Level	2568 MWt (900 MWe)
NSSS Vendor	B & W

Facility Unique Features

Emergency Supply to 4160 Volt-AC Safety-Related Buses

Provided from the two hydro units at the adjacent Keowee Hydro Station, the onsite emergency AC power supply is not Train separated by source. A single Keowee Hydro Unit (KHU) will supply all emergency power. Should a failure occur, the other KHU will supply power. This power is supplied to Oconee by two connections; an overhead transmission line and an underground line. [Note: gas turbines at the Lee Steam Station can also be made available (manually, via a separate overhead line) to provide power if Keowee is not available.] Keowee was originally built, operated and maintained to Duke's hydro station standards; therefore, a number of modifications/upgrades have been necessary over the last ten years (i.e., procedure upgrades, engineering analyses, maintenance program development, significant testing, circuit breaker and underground cable replacements, weld overlay/repairs to the KHU turbine blades and guide rings, and modifications pertaining to auxiliary power and over voltage/under frequency issues).

Standby Shutdown Facility (SSF)

The SSF, which is unique to the Duke Facilities, provides an alternate and independent means to achieve and maintain a hot standby condition for any unit following postulated turbine building flood, fire, and sabotage events. [Note: The proposed Tornado/HELB mitigation strategies also take credit for the SSF.] It consists mainly of one diesel generator set, an auxiliary service water pump, and supporting equipment (all housed in an onsite seismically qualified building), three standby makeup pumps (one in each unit's reactor building), strainers, valves, and associated piping. Powered from the SSF diesel, the standby makeup pumps deliver water at approximately 26 gpm from the associated spent fuel pool to the reactor coolant pump seals. In support of primary decay heat removal, the SSF diesel supplied electric auxiliary service water pump supplies water from the condenser circulating water (CCW) cross-over header to the once-through steam generators. The SSF is able to maintain all three units in Mode 3 (525 degrees) for 72 hours, at which point, it is assumed that the other mitigating systems will be repaired and returned to service.

Low Pressure Service Water (LPSW)

As originally designed, long-term decay heat removal has relied on the non-safety, non-seismically qualified CCW piping system and its pumps to provide water to the safety-related LPSW pumps located in the turbine building basement. During loss of offsite power events, the CCW pumps lose power; therefore, decay heat removal and cooling water for safety-related pumps rely on the use of a siphon effect (between the lake and the CCW cross-over header) to provide water to the safety-related LPSW system. Accordingly, to maintain the siphon and assure LPSW system operability, a number of modifications/upgrades were completed in recent years (e.g., installation of a QA-1 siphon vacuum system, supplying safety-related sealing/cooling water to CCW pumps, reclassifying the CCW interface boundary to QA-1, etc.).

Emergency Feedwater (EFW)

The safety-related turbine driven EFW pump (one for each unit) and the motor driven EFW pumps (two for each unit) are located in the turbine building basement. The turbine driven EFW pump in each unit can be aligned to either its safety-related main steam supply or to a non-safety-related, non-seismically qualified auxiliary steam header. The EFW system does not have a dedicated, seismically qualified source of water of sufficient capacity to bring the unit(s) to the point where low pressure injection cooldown can be initiated. Specifically, each unit's EFW system must rely on the limited source of water in its seismically qualified upper surge tank, as well as depend on the water contained in the condenser hotwell. Cross-connect valves are, however, provided between all three units' EFW systems. Identified EFW single failure vulnerabilities have been addressed through plant modifications and licensing basis changes/clarifications.

Containment Isolation

Several piping systems penetrating containment were designed without isolation valves (Main Steam), or redundant, reliable (QA Level 1) isolation devices (Main Feedwater). Operator actions were required in some cases to prevent consequences beyond "standard" design basis accident end points. For containment integrity concerns, the licensee implemented a modification several years ago in all three units which automatically secures/isolates main feedwater upon a steam line break event. During the Spring 2002 Unit 1 refueling outage, and subsequent Unit 2 and 3 refueling outages, a new automatic feedwater isolation system (AFIS) modification was installed that secures/isolates both main and emergency feedwater to the affected steam generator. (Note: Due to a recently developed small steam line break scenario that results in a delayed feedwater isolation signal, temporary diesel air compressors are continuously run to compensate for the expected bleed off of valve operating air pressure should a coincident loss of offsite power occur.)

Reactor Oversight Process Info

The following URLs are for the Oconee Nuclear Station (Units 1, 2 and 3) ROP Performance Summary web pages.

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO1/oco1_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO2/oco2_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO3/oco3_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/pi_summary.html

ROP Performance Status (1st Quarter 2008 - 4th Quarter 2008)

Performance of Oconee Units 1, 2 and 3 during 2008 was within in the Licensee Response Column of the NRC's Action Matrix. All findings and PIs over the assessment period were **GREEN**.

Note: A Regulatory Conference was held with Duke on January 22, 2009, for the Unit 1 loss of inventory event. A caucus was held on January 28, 2008, to finalize the significance determination. [PREDECISIONAL INFORMATION - Preliminary results, including addressing the licensee's comments on the risk, are that the finding will be **WHITE**. This would put Unit 1 in the Regulatory Response Column as of the 4th quarter of 2008.]

Current Issues

A. EXPECTED DISCUSSION TOPICS

Flood Action Plan
Using the Significance Determination Process (SDP), the staff initially evaluated a performance deficiency of a breached flood barrier to the Oconee SSF. During a re-evaluation on licensee appeal, it was discovered that the licensee had erroneously used a significantly lower random Jocassee Dam rupture frequency in their site external flooding analysis for the Individual Plant Examination of External Events. An approach using the techniques of NUREG/CR-6823, "Handbook of Parameter Estimation for Probabilistic Risk Assessment," was used to verify this. Upon further review, it was discovered that an earlier alternate approach had underestimated dam rupture frequency published in NSAC-60, "Oconee PRA; a probabilistic risk assessment of Oconee Unit 3," a document which is referenced throughout the industry by other licensees in their flooding analyses. Consequently, an internal NRC backfit assessment/flood action plan was implemented. A 50.54(f) letter was issued on August 15, 2008, concerning this "inadequate protection" issue. On November 5, 2008, NRC and Licensee Management met to discuss: concerns with the SSF licensing basis with respect to flooding, as addressed in the related 50.54(f) letter; short-term interim measures for ONS operation; and a long-term solution to the question of flood protection at the ONS site. Current concerns are that the SSF is the only mitigating system that is currently protected from this event; however, it is only protected to a flood height of 5 feet and can only mitigate the effects of this event for 72 hours before the SSF standby makeup systems will deplete the spent fuel pool water inventories. Additionally, the licensee's response to the 50.54(f) letter was insufficient. NRR met with the Federal Energy Regulatory Commission (FERC) on December 1, 2008, to discuss generic issues related to the Jocassee dam inundation study performed by Oconee. A technical exchange meeting was held December 4, 2008, to work out details on the probabilistic and consequence analyses. Licensee tours of the Jocassee Dam were provided to the Regional Administrator on December 10, 2008, and to NRR and Regional management (Skeen, Galloway and Wert) on January 8, 2009. NRR is currently assessing the options regarding a final response to the licensee's 50.54(f) response.

Tornado Mitigation
As a result of a 95002 supplemental inspection of two White Mitigating System tornado-related findings in 2001, it was determined that Oconee has a number of tornado-related vulnerabilities that collectively represent a deficient tornado mitigation strategy. Duke has subsequently provided its resolution to this matter by proposing the use of two redundant and largely separate tornado mitigation systems (i.e., the SSF and a planned PSW system). The licensee has already started civil/site work on the PSW system and the Unit 3 control room wall missile protection modifications are also underway. Duke has also informed the NRC that difficulty in meeting the Standard Review Plan TORMIS risk acceptance criteria (1.0E-6) will result in the need for more missile protection than originally thought. The Tornado Mitigation LAR was submitted June 26, 2008, and has been accepted (Rare Circumstances) by NRR.

HELB Mitigation
Following a 1998 self-assessment of Oconee's licensing basis for HELB events outside containment, Duke notified the NRC in January 1999 that it was initiating a project to reconstitute the design and licensing basis for HELBs outside the reactor building. The NRC staff is concerned that the analyses that were completed by Duke in 1973 for addressing postulated high energy pipe failures in the auxiliary building do not adequately consider and address the potential consequences of postulated HELB events.

Duke analysis of 1973 did not adequately consider issues such as physical arrangement of structures, systems and components (SSCs) in the penetration rooms, the lack of separation, the absence of barriers for preventing pipe whip, jet impingement, and migration of steam and water, and the proximity of important SSCs to postulated pipe break locations. For example, a postulated feedwater line break in the auxiliary building could impact both trains of HPI/LPI, RCP seal injection and thermal barrier cooling, letdown, EFW, vital batteries, and numerous electrical penetrations.

Oconee's Unit 1 HELB mitigation LAR (which includes the use of existing safety systems, along with the SSF and planned installation of the PSW system and main steam isolation valves) was submitted June 26, 2008, and accepted (Rare Circumstances) by NRR. A LAR for Unit 2 was submitted in December 2008 and a Unit 3 LAR will be submitted in June 2009.

NFPA 805 Transition
Oconee is one of two pilot plants that are in the process of transitioning to NFPA 805 for fire protection. LAR No. 2008-01, to adopt NFPA 805, was submitted for all three Units on May 30, 2008. On October 31, 2008, the licensee submitted, as a supplement to the LAR, the fire probabilistic risk assessment model, change evaluations, and proposed modifications. NRR is planning an on-site review of the submittal in February 2009.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)
By letter dated January 31, 2008, Duke submitted a LAR that would allow replacement of the current analog-based RPS/ESPS with a digital computer based RPS/ESPS. By letter dated April 24, 2008, the NRC staff stated that Duke had provided sufficient information to accept the LAR and start a comprehensive review of the LAR. The letter identified six issues (discussed with Duke in a March 18, 2008, public meeting) that presented significant challenges to completing a comprehensive review of the LAR. Four members of NRR/EICB visited Oconee the week of May 19, 2008, and resolved these issues. Implementation is scheduled to begin in Fall 2010 or Spring 2011 following development of modification packages.

William States Lee III Nuclear Station Combined Operating License (COL) Application
Duke Energy submitted a 10 CFR 52 application for a combined operating licensee to the NRC on December 13, 2007, which was docketed on February 25, 2008. A public scoping meeting was also held on May 1, 2008, near the proposed site location. The license application references the Westinghouse AP1000 as the reactor type and two reactors are planned for the site. The location is just south of the North Carolina/South Carolina border near Gaffney, S.C. The site can be reached by taking I-85 from Charlotte, N.C. to exit 96 (approximately 50 miles), then going south about 10 miles.

Unit 1 Loss of Inventory Event
On April 12, 2008, Oconee Unit 1 shut down for refueling. On April 15, 2008, Unit 1 had restored level, from a midloop operation to install coldleg nozzle dams, to below the reactor vessel flange. The head was detensioned in preparation for removal. As part of main generator voltage regulator modification testing, a main generator lockout signal was generated while the switchyard was back-feeding all Unit 1 electrical loads through the main transformer and the associated auxiliary transformer. This caused a slow transfer from the aux transformer to backup transformer (CT1) from the switchyard. The resulting electrical transient caused a momentary loss of power to the running pumps performing shutdown cooling (SDC) and, due to one complication, a relief valve in the letdown purification system opened and remained open as designed. This transient caused a loss of inventory (LOI) from the reactor coolant system (RCS) to the miscellaneous waste holdup tank (MWHUT). The operators quickly recognized the LOI and entered the appropriate procedures. They had the relief valve isolated and makeup water going into the RCS within 17 minutes. During the RCS level transient, level dropped from 70 inches above hotleg midloop to approximately 55 inches. Approximately 2000 gallons were transferred from the RCS to the MWHUT. The root cause of the generator lockout was determined to be a failure of the procedure preparers and reviewers of IP/0/B/2005/001, "Main Generator Automatic Voltage Regulator (AVR) Maintenance and Channel Transfer," to recognize the system interaction between the AVR trip circuitry and the backcharge power path; therefore, steps to isolate actuation of the K31 relay were not included in the procedure. A Significance and Enforcement Review Panel was conducted on Wednesday, November 12, 2008, and a "Greater than Green" preliminary determination letter was sent to the licensee on November 21, 2008. Note: A Regulatory Conference was held with Duke on January 22, 2009, and a caucus was held on January 28, 2008, to finalize the significance determination. [PREDECISIONAL INFORMATION - Preliminary results, including addressing the licensee's comments on the risk, are that the finding will be **WHITE**. This would put Unit 1 in the Regulatory Response Column.]

Unit 3 Reactor Trip
At 0834 hours on November 7, 2008, a Unit 3 reactor trip occurred. The Events Recorder and Operator Aid Computer (OAC) first-out alarms were "reactor trip confirm" signals out of the Control Rod Drive (CRD) system. The transient response of the unit was normal and operator actions were appropriate with no complications. The licensee's investigation determined that the trip was a result of a simultaneous shutdown of the CRD digital primary processors P1 and P2 which caused the system to go to a fail-safe condition as designed which ultimately de-energized all rods. The shutdown of the processors was caused by an erroneous time signal from the satellite clock repeater for Unit 3, which is used for a time stamping function in the CRD system. The bad time signal also caused a reset of the Unit 3 control room clock and OAC time stamp. On Sunday, November 9, 2008, the Plant Operations Review Committee convened (Senior Resident attended) and made the decision to restart Unit 3 following the disconnection of the clock input to the CRD system as there are no other external synchronous inputs to the CRD system that could have the same effect. Subsequent to the implementation of the modification, Unit 3 was returned to power operations on November 9, 2008. The same modification was also performed on Unit 1 (Unit 2 was not affected).

Approval for Additional Resident Inspector
A temporary third resident has been authorized for the Oconee site due to the large number of permanent plant modifications associated with Tornado/HELB issues, NFPA 805 implementation, conversion to a digital Reactor Protection System/Engineered Safeguards Protective System, and the addition of Main Steam Isolation Valves. These modifications are both complex and important to safety. The third resident will provide additional oversight of the modification work and will coordinate inspection efforts of specialist inspectors from Region II.

INPO Rating and Nuclear Performance Plan

(b)(4)

B. OTHER TOPICS OF INTEREST

Labor/Management Issues

None

License Renewal Activities

None

Escalated Enforcement, Non-Green Findings and Non-Green Performance Indicators

Other than the Unit 1 loss of inventory event discussed above, there has been no escalated enforcement or the identification of any Greater than Green findings or performance indicators within the last year.

Open Investigations

Two items are under Office of Investigations (OI) review. One involves the discovery of an illegal substance inside the Protected Area at Oconee Nuclear Station. Another involves personnel at McGuire Nuclear Station that were aware of illegal drug use, but failed to report this information to the licensee.

Open Allegations

Two allegations are open. One involves the discovery of an illegal substance inside the Protected Area. Another involves personnel at McGuire that were aware of illegal drug use, but failed to report this information to the licensee. Both are being investigated by OI.

Congressional Interest

None

Harassment and Intimidation Issues

None

2.206 Petitions

None

Recent News Articles

On January 23, 2009

(b)(4)

(b)(4)

(b)(4)

(b)(4)

On January 12, 2009

(b)(4)

(b)(4)

On December 1, 2008

(b)(4)

On November 26, 2008

(b)(4)

On November 17, 2008

(b)(4)

On November 12, 2008

(b)(4)

Facility Organization

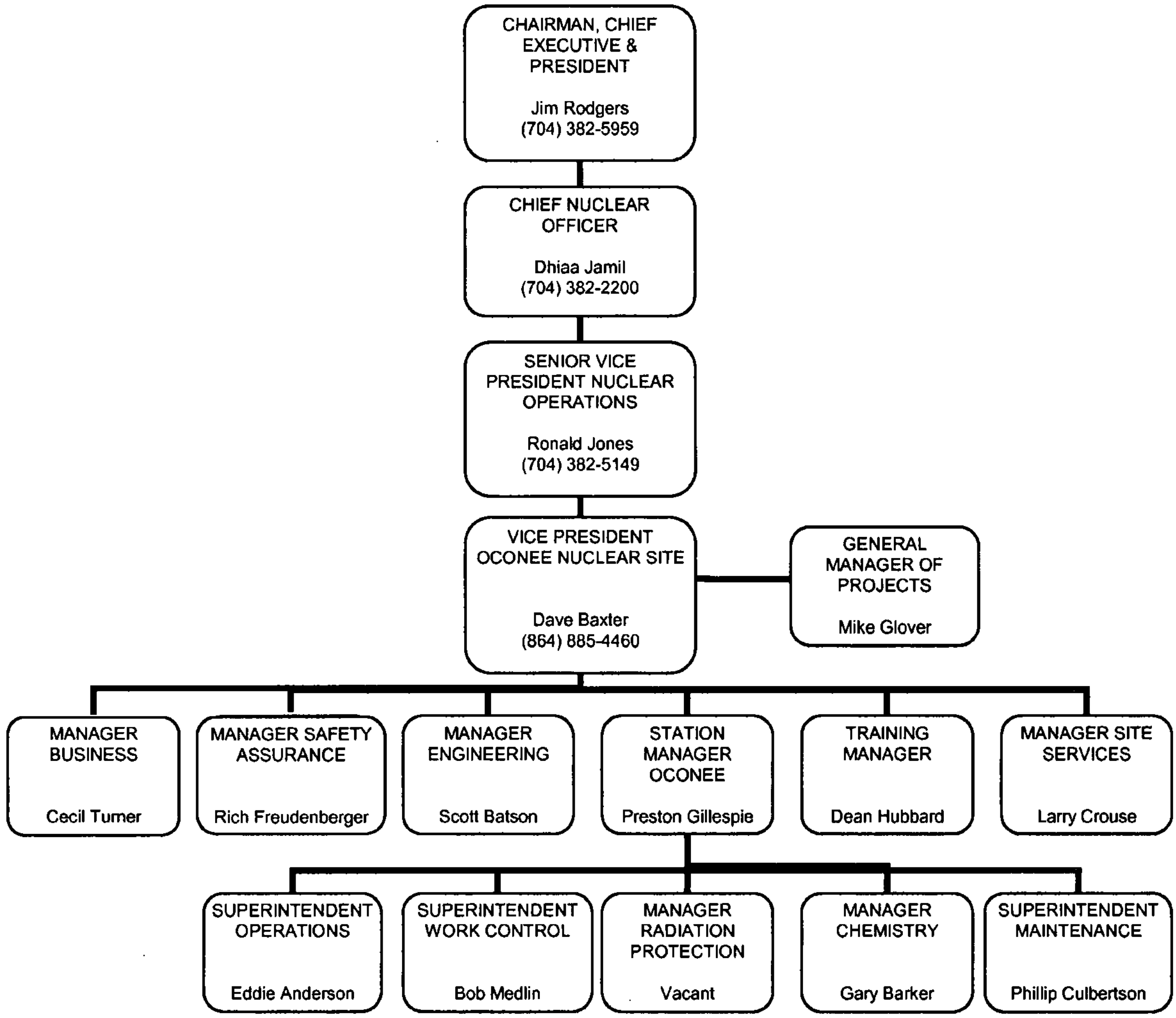
OVERVIEW OF DUKE ENERGY

Duke Energy Carolinas
Duke Energy Carolinas' operations include nuclear, coal-fired, natural gas, and hydroelectric generation. This diverse fuel mix provides nearly 21,000 megawatts (MW) of safe, reliable and competitively priced electricity to more than 2.3 million electric customers in a 24,000 square-mile service area of North Carolina and South Carolina.

Generation Assets
Duke Energy Carolinas generates energy primarily from three nuclear generating stations with a combined net capacity of 6,996 MW, eight coal-fired stations with a combined capacity of 7,699 MW, thirty-one hydroelectric stations with a combined capacity of 2,693 MW, and six combustion turbine stations with a combined capacity of 2,861 MW. Duke Energy Carolinas owns and operates the two-unit McGuire and the three-unit Oconee nuclear stations. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station.

New Nuclear Generation
Duke Energy submitted a 10 CFR 52 application for a combined operating licensee to the NRC on December 13, 2007, which was docketed on February 25, 2008. A public scoping meeting was also held on May 1, 2008, near the proposed site location. The license application references the Westinghouse AP1000 as the reactor type and two reactors are planned for the site. The location is just south of the North Carolina/South Carolina border near Gaffney, S.C. The site can be reached by taking I-85 from Charlotte, N.C. to exit 96 (approximately 50 miles), then going south about 10 miles.

DUKE ENERGY
OCONEE NUCLEAR STATION
ORGANIZATIONAL CHART



Biographical Data of Principal Managers

Dhiaa M. Jamil
Group Executive and Chief Nuclear Officer

Dhiaa Jamil is Group Executive and Chief Nuclear Officer for Duke Energy. He is responsible for the safe and efficient operation of the company's three nuclear generating stations - Catawba, McGuire and Oconee nuclear stations. He was named to his current position in January 2008.

Mr. Jamil has more than 25 years of experience in the energy industry.

Most recently, Mr. Jamil served as Senior Vice President of nuclear support. He led the organization responsible for plant support, major projects and fuel management for Duke Energy's nuclear fleet. In addition, he was responsible for regulatory support, nuclear oversight and safety analysis functions.

He joined Duke Power in 1981 as a design engineer in the design engineering department. After a series of promotions, he was named Electrical Systems Engineering Supervisor of Oconee Nuclear Station in 1989 and Electrical Systems Engineering Manager in 1994. He was named Maintenance Superintendent of McGuire Nuclear Station in 1997, Station Manager in 1999, and Site Vice President of McGuire Nuclear Station in 2002. In that role, Mr. Jamil was responsible for all aspects of the safe and efficient operation of the nuclear site. He was appointed Site Vice President of Catawba Nuclear Station in 2003.

Mr. Jamil received a Bachelor of Science degree in Electrical Engineering from the University of North Carolina at Charlotte.

He is a registered Professional Engineer in North Carolina and South Carolina. He has completed the Institute of Nuclear Power Operations (INPO) Senior Nuclear Plant Management course and received Duke Energy's technical nuclear certification. He has served as a senior member of the Institute of Electrical & Electronics Engineers (IEEE) and has completed a three-year assignment as a member of the Council of the National Academy for Nuclear Training. He is a former member of Dominion Energy Management Safety Review Advisory Committee, TVA Nuclear Safety Review Board, and Pacific Gas & Electric Nuclear Safety Oversight Committee. He also served on the board of directors of the York County, S.C. Chamber of Commerce.

Mr. Jamil is currently a member of the board of directors of the Charlotte Research Institute and serves on an advisory board for the School of Engineering at the University of South Carolina. He is a member of INPO's Executive Advisory Group, the Nuclear Energy Institute (NEI) New Plant Oversight Committee, and the NEI Nuclear Strategic Issues Advisory Committee Steering Group.

(b)(6)

Ronald A. Jones
Senior Vice President - Nuclear Operations

Ron Jones is senior vice president of nuclear operations for Duke Energy. He provides oversight for the safe and reliable operation of the three Duke Energy-operated nuclear stations – Catawba, McGuire and Oconee. He was named to his current position in January 2006. In addition to this role, Jones assumed responsibility for the nuclear fleet support and major projects organizations in February 2008.

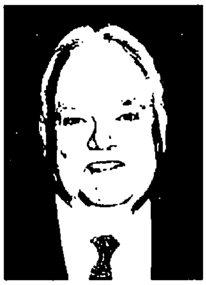
Jones has more than 27 years experience in the nuclear field.

He joined Duke Power in 1980 as an engineer at Catawba Nuclear Station. He received his senior reactor operator license in 1987. After a series of promotions, he was named manager of maintenance engineering in 1988; superintendent of instrument and electrical in 1991; superintendent of operations at McGuire Nuclear Station in 1994; station manager of Catawba Nuclear Station in 1997; station manager of Oconee Nuclear Station in 2001; and vice president of Oconee Nuclear Station in 2002.

The (b)(6) [redacted] graduated from Virginia Tech in Blacksburg, Va., with a Bachelor of Science degree in Electrical Engineering.

Jones is a member of the American Nuclear Society and the Institute of Electrical and Electronic Engineers; chairman of the Pressurized Water Reactors Owners Group Executive Management Group and Executive Committee; chairman of the Carolinas Nuclear Cluster; and an executive member of the Nuclear Energy Institute Nuclear Security and Workforce Working Groups. He is currently a member of the board of directors for Junior Achievement of the Central Carolinas and the Lake Norman Charter School.

(b)(6) [redacted]



David A. Baxter
Site Vice President
Oconee Nuclear Station

Dave Baxter is site vice president of Oconee Nuclear Station in Seneca, S.C. Baxter is responsible for the safe and reliable operation of Oconee Nuclear Station, a three-unit, pressurized water-reactor nuclear generating facility. He directs station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations.

Baxter has over 28 years of experience in nuclear engineering with Duke Energy.

Baxter joined the company in 1979 as a junior engineer at McGuire Nuclear Station in Huntersville, N.C. After a series of promotions at McGuire, including operations staff engineer, operations shift technical advisor, operations shift engineer and operations section manager, he was named nuclear engineering manager for modifications at Catawba Nuclear Station in 1998; and nuclear engineering manager for mechanical and civil engineering in 1999. He was named engineering division manager of Oconee Nuclear Station in 2002; and station manager in 2006. In that role, he was responsible for managing all aspects of Oconee's day-to-day operations. He was named to his current position in January 2008.

The (b)(6) earned a Bachelor of Science degree in Nuclear Engineering from Pennsylvania State University.

Baxter has received a U.S. Nuclear Regulatory Commission Senior Reactor Operator License and the Institute of Nuclear Power Operations' Senior Nuclear Plant Management Certification. He also served as a member of the B&W Owners Group Steering Committee. He is currently a board member of the Oconee Memorial Hospital Foundation and the United Way of Oconee County.

(b)(6)

R. Michael Glover
General Manager Nuclear Plant Projects
Oconee Nuclear Station

Mike Glover is general manager, plant projects at Oconee Nuclear Station for Duke Energy. He is responsible for leading the station's plan to address recently identified improvement areas and providing senior management oversight for both Oconee special regulatory projects and the integration of Oconee major projects into the station's site processes. He was named to his current position in October 2008.

Most recently, Glover served as station manager of Oconee Nuclear Station. He managed all aspects of operation, maintenance, work control, radiation protection and chemistry activities at the station to provide safe, reliable and efficient electrical service for customers.

Glover joined Duke Power in 1975 as a junior engineer in the nuclear fuel services group. Glover received his senior reactor operator license in 1987. After a series of promotions, he was named manager of the shift engineers in 1987; unit 2 operations manager then station compliance group manager for units 1 and 2 in 1988; performance group manager in 1990; operations unit manager in 1992; electric systems support customer service manager in 1993; mechanical and electrical systems engineering manager in 1995; and operations superintendent in 1997. He was named station manager at Catawba Nuclear Station in 2001 and continued in that role until 2005. Glover transferred to Oconee Nuclear Station in the latter part of 2005 to lead the engineering organization. In that role, he was responsible for managing activities related to system, component, and modification engineering.

A (b)(6) Glover graduated with honors from the University of Virginia with a Bachelor of Science degree in Nuclear Engineering. He is a registered professional engineer in North Carolina.

(b)(6)

T. Preston Gillespie, Jr.
Station Manager
Oconee Nuclear Station

Preston Gillespie is station manager of Oconee Nuclear Station for Duke Energy. He is responsible for managing all aspects of operation, maintenance, work control, radiation protection and chemistry activities at the station to provide safe, reliable and efficient electrical service for customers.

Gillespie joined Duke Power in 1986 as an assistant engineer at Oconee Nuclear Station in Seneca, S.C. He served in a variety of positions while at the station, including nuclear production engineer, senior engineer, shift work manager, nuclear shift supervisor, nuclear operations shift manager and shift operations manager. In 2004, he was named nuclear engineering manager at Oconee, where he managed activities for the station's engineering organization. In addition, he was responsible for the reliable operation of electrical systems and equipment. He was named operations superintendent at Catawba Nuclear Station in March 2007 where he was responsible for the safe and reliable operation of the station's two nuclear units. He assumed his current position at Oconee Nuclear Station in October 2008.

The (b)(6) graduated from Clemson University with a Bachelor of Science degree in Mechanical Engineering.

Gillespie is a registered professional engineer in South Carolina. He has held a senior reactor operator license at Oconee Nuclear Station. He is also a past recipient of the company's Robinson Award, which recognized employees for their outstanding contributions to the company's operations.

(b)(6)

Scott L. Batson
Engineering Manager
Oconee Nuclear Station

Scott Batson is engineering manager of Oconee Nuclear Station for Duke Energy. He is responsible for managing and directing activities at the station related to system, component, and modification engineering to provide safe, reliable and efficient electrical service for customers.

Batson joined the company in January 1985 as a junior engineer at Oconee Nuclear Station in Seneca, S.C. He has held various leadership positions at Oconee, including operations shift manager, maintenance instrument and electrical section manager, and mechanical and civil engineering manager. His most recent position as Operations Superintendent was responsible for managing all aspects of operations activities at the station and at Keowee Hydro Station. He was named to his current position in January 2008.

Batson has over 22 years of experience in plant operation and engineering with Duke Energy.

The (b)(6) earned a Bachelor of Science degree in Mechanical Engineering from Clemson University.

Batson is a registered professional engineer in South Carolina. He received a senior reactor operator license from the U.S. Nuclear Regulatory Commission and a senior nuclear plant management certification from the Institute of Nuclear Power Operations. He has also completed the Duke Energy Advanced Leadership Program.

(b)(6)

Richard J. Freudenberger
Safety Assurance Manager
Oconee Nuclear Station

Rich Freudenberger is safety assurance manager of Oconee Nuclear Station for Duke Energy. He is responsible for the management of site programs and processes related to environmental health and safety, regulatory compliance, performance improvement, emergency planning and security.

Prior to joining Duke Power in 1997, Freudenberger had 12 years of commercial nuclear power experience as a resident and senior resident inspector for the Nuclear Regulatory Commission at the Maine Yankee, Crystal River, and Catawba nuclear stations. His first position with Duke Power was in the Charlotte, N.C. office as the regulatory audit supervisor. He was responsible for implementation of performance-based audits required by the Duke Energy Nuclear Quality Assurance program.

In February 2000, Freudenberger was assigned to Oconee Nuclear Station as the secondary systems engineering supervisor. In this role, he was responsible for the power conversion and standby shutdown systems mechanical design and licensing basis, testing support and equipment reliability. He was named valve engineering supervisor in 2001 and was responsible for design basis, margin management and equipment reliability of valves, valve actuators and heat exchangers.

In mid-2002, Freudenberger was assigned to an operator licensing class. He successfully completed the program and was licensed as a senior reactor operator in July 2004. In November 2004, he was reassigned as the primary systems engineering supervisor. He was responsible for the nuclear steam supply systems mechanical design and licensing basis, testing support and equipment reliability. In December 2005, Freudenberger was assigned to lead a team of engineers and licensing personnel to address two long-standing licensing basis issues. An agreement with the Nuclear Regulatory Commission for issue resolution was achieved in 2007.

Freudenberger was appointed safety assurance manager of Oconee Nuclear Station in January 2008.

Résumés of Resident Inspectors

George A. (Andy) Hutto
Senior Resident Inspector
Oconee Nuclear Station

Andy Hutto joined the Nuclear Regulatory Commission in December 1997. He is a (b)(6) (b)(6) He has been the Senior Resident Inspector at the Oconee Nuclear Station since March 2008.

Mr. Hutto received his Bachelor's Degree in Biochemistry from Clemson University in (b)(6) Subsequently, Mr. Hutto received a Master's degree in Environmental Systems Engineering (nuclear core curriculum) from Clemson in (b)(6)

Mr. Hutto began his career in 1984 as an environmental engineer with the South Carolina Department of Health and Environmental Control. His primary responsibilities included oversight of the low-level radioactive waste disposal facility at Barnwell. Mr. Hutto joined the Charleston Naval Shipyard as a nuclear engineer in 1986. While at the shipyard, Mr. Hutto achieved qualification as a nuclear shift test engineer on several submarine reactor plant designs. Following closure of the shipyard in 1993, Mr. Hutto accepted a project manager position with the Naval Facilities Engineering Command in Charleston, where he managed environmental cleanup projects at a number of Navy and Marine Corps bases in the southeast.

In the NRC, Mr. Hutto was initially hired as a project engineer in Region II, Division of Reactor Projects. Shortly after arriving at Region II, Mr. Hutto was assigned as resident inspector at the H. B. Robinson Plant. Mr. Hutto completed his certification as a Westinghouse Pressurized Water Reactor Operations Inspector in 1999, and in January 2003 transferred to the Oconee Nuclear Station to fill a vacant RI position. Mr. Hutto was promoted to the Oconee Senior Resident Inspector position in March 2008.

Eric T. Riggs
Resident Inspector
Oconee Nuclear Station

Eric Riggs joined the U. S. Nuclear Regulatory Commission in 2002. He is a (b)(6) (b)(6) He has been a resident inspector at the Oconee Nuclear Station since December 2002.

Mr. Riggs received his bachelor's degree in Mechanical Engineering from the Pennsylvania State University in (b)(6) After attending Pennsylvania State University, Mr. Riggs worked as a Faculty Research Assistant/Engineer at Penn State's Applied Research Laboratory.

Mr. Riggs began his career in the nuclear industry in the U.S. Navy Nuclear Power program from 1988 to 1994. While in the Navy, he served as an Engineering Laboratory Technician (ELT) instructor at the S8G prototype and the Leading ELT aboard the USS Tennessee (SSBN 734).

In the NRC, Mr. Riggs was initially hired as a project engineer in Region II, Division of Reactor Projects. Shortly after arriving at Region II, Mr. Riggs was assigned as resident inspector at the Oconee Nuclear Station.

Geoffrey K. Ottenberg
Resident Inspector
Oconee Nuclear Station

Geoff Ottenberg joined the U. S. Nuclear Regulatory Commission in 2004. He is a (b)(6) (b)(6) He has been a resident inspector at the Oconee Nuclear Station since September 2008.

Mr. Ottenberg received his bachelor's degree in Mechanical Engineering from the Florida State University in (b)(6) Mr. Ottenberg is a registered engineer intern in the State of Florida. After attending Florida State University, Mr. Ottenberg worked as a researcher at Argonne National Laboratory on a fellowship assignment.

In the NRC, Mr. Ottenberg was initially hired as a reactor engineer in Region I, Division of Reactor Projects. After qualifying as an inspector, Mr. Ottenberg worked in Region I, Division of Reactor Safety, as a reactor inspector doing primarily Component Design Basis Inspections, and also completed a 6-month rotation as resident inspector at the Susquehanna Steam Electric Station.

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

BACKGROUND INFORMATION

FOR

ERIC LEEDS

DIRECTOR OFFICE OF NUCLEAR REACTOR REGULATION

DUKE ENERGY CAROLINAS, LLC

MANAGEMENT DROP IN VISIT REGION II

MARCH 18, 2010

D 46

Agenda for Eric Leeds's Drop-in Visit in Region II
Oconee Management – March 18, 2010

March 15, 2010 @ 2:30pm DORL PM Prebrief

March 18 9:00 a.m. Region II Meeting with Duke Management (Ron Jones Oversight VP, Bill Pitesa Oversight VP, Jim Morris Site VP, Regis Repko Site VP, Dave Baxter Site VP and Dhiaa Jamil CNO)

NRC Participants (Luis Reyes Region II RA, Victor McCree Region II DRA, Eric Leeds NRR)

Recommended Discussion Topics and Questions

1. Duke Organizational Change (See Regional Information for all changes)

    Oconee Station now answering directly to Bill Pitesa instead of Ron Jones

    Questions for Duke

    Purpose of the reorganization?

    There have been a number of upper level management changes both at the Sites and General Office. What will you use to measure the effectiveness of the changes?

2. Duke Nuclear Initiatives

    Questions for Duke

    What are the major fleet nuclear initiatives? Do you feel you have enough resources to complete them in a timely manner? It seems that each major project at Oconee has slipped (NFPA 805, Tornado and HELB modifications.) are more resources necessary to complete the major projects in a timely manner.

3. Duke Fleet Performance

    Oconee dropped from INPO 1 to INPO 2 in summer 2008. (Catawba and McGuire both INPO 1)

    Last inspection report documented 5 violations at Oconee.

    Question for Duke

    Do you feel that performance has improved at Catawba, McGuire and Oconee in the last year? If so please provide examples of improvements.

4. NFPA 805 Transition

Question for Duke

Will the Oconee April 15, 2010, Amendment be a complete submittal? The NRC staff has made numerous site visits, held several meeting, and phones to discuss this issue.

5. Tornado/High Energy Line Break (HELB)

Tornado Mitigation

As a result of a 95002 supplemental inspection of two White Mitigating System tornado-related findings in 2001, it was determined that Oconee has a number of tornado-related vulnerabilities that collectively represent a deficient tornado mitigation strategy. Duke has subsequently provided its resolution to this matter by proposing the use of two redundant and largely separate tornado mitigation systems (i.e., the SSF and a planned Protected Service Water (PSW) system). The licensee has already started civil/site work on the PSW system and the Unit 3 control room wall missile protection modifications are also underway. Duke has also informed the NRC that difficulty in meeting the Standard Review Plan TORMIS risk acceptance criteria (1.0E-6) will result in the need for more missile protection than originally thought. The Tornado Mitigation license amendments requests (LARs were submitted June 26, 2008 and June 29, 2009). The NRR staff is currently reviewing the LARs and has requested additional information (RAIs) from the licensee. The licensee is working on responses to the RAIs.

Submittal is still not complete. Mitigating strategies require the installation of Main Steam Isolation Valves (MSIVs.) Analysis associated with the MSIVs has not been completed.

HELB Mitigation

Following a 1998 self-assessment of Oconee's licensing basis for HELB events outside containment, Duke notified the NRC in January 1999 that it was initiating a project to reconstitute the design and licensing basis for HELBs outside the reactor building. The NRC staff is concerned that the analyses that were completed by Duke in 1973 for addressing postulated high energy pipe failures in the auxiliary building do not adequately consider and address the potential consequences of postulated HELB events.

Duke analysis of 1973 did not adequately consider issues such as physical arrangement of structures, systems and components (SSCs) in the penetration rooms, the lack of separation, the absence of barriers for preventing pipe whip, jet impingement, and migration of steam and water, and the proximity of important SSCs to postulated pipe break locations. For example, a postulated feedwater line break in the auxiliary building could impact both trains of High and Low Pressure Injection capability , Reactor Coolant Pump Seal Injection and Thermal Barrier Cooling, Letdown, Emergency Feedwater , Vital Batteries, and numerous electrical penetrations.

Oconee's Unit 1 HELB mitigation LAR (which includes the use of existing safety systems, along with the SSF and planned installation of the PSW system and main steam isolation

valves) was submitted June 26, 2008, and accepted (Rare Circumstances) by NRR. A LAR for Unit 2 was submitted in December 2008 and a Unit 3 LAR was submitted June 29, 2009 (LICENSEE DID NOT INCLUDE INFORMATION ON THE INSTALLATION OF MSIVs). The NRR staff is currently reviewing the LARs and has issued numerous RAIs. The licensee is in the process of responding to the RAIs.

Questions for Duke — When will all the information required for NRC staff review be provided to the NRC.

When will all the plant modifications be completed?

6. External Flooding (Resolution of Failure of the Jocassee Dam)

On August 15, 2008, the Nuclear Regulatory Commission (NRC) issued a request for information pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 50.54(f), regarding the protection against external flooding at Oconee, including the potential failure of the Jocassee Dam. Duke responded to the NRC letter on September 26, 2008. The NRC staff reviewed the letter and found that Duke had not provided sufficient information to demonstrate that Oconee will be adequately protected from external flooding events. Subsequently, on April 30, 2009, the NRC issued a letter to Duke requesting additional information to demonstrate that Oconee will be adequately protected from external flooding events. The NRC April 30, 2009, letter requested that Duke provide analyses which would establish an adequate licensing basis for external flooding at Oconee by November 2009, including a schedule for any site modifications necessary to mitigate an external flooding event.

Several closed meetings and telephone conference calls have taken place in order for the NRC staff to obtain a better understanding of the technical issues. By letter dated November 30, 2009, Duke provided a response to the NRC April 30, 2009, letter. Based on a preliminary review of the November 30, 2009, letter, the NRC staff determined that although Duke provided a more accurate estimate of the flooding caused by a failure of the Jocassee Dam (Approximately 18 ft), the NRC staff finds that additional information is needed. This information is necessary for the NRC staff to determine if the analyses performed to date will demonstrate, for the entire Jocassee earthen works, that the Oconee site will be adequately protected from external flooding events. By letter dated January 29, 2010, the NRC issued RAIs. By letter dated March 5, 2010, the licensee responded to the RAIs. The NRR staff is currently reviewing the licensee's response.

By letter dated January 15, 2010, Duke submitted a letter to the NRC which provided its interim compensatory measures (ICMs) to ensure that the Oconee site will be adequately protected from external flooding events until the final mitigating strategies have been implemented and all site modifications have been completed. The NRC staff will perform a further review of the ICMs, and will perform a future inspection.

Question for Duke

What is your tentative schedule for making modifications for external flooding based on the results of your analyses? How will making these modifications affect the other large projects currently underway at Oconee.

7. Digital I&C

By letter dated January 31, 2008, Duke submitted a LAR that would allow replacement of the current analog-based RPS/ESPS with a digital computer based RPS/ESPS. The NRR staff has conducted related audits at the Oconee site, at the AREVA facility in Alpharetta, Georgia, and at the AREVA facility in Erlangen, Germany (factory acceptance testing). During the review of the LAR, the NRC staff has generated numerous RAIs. The NRC issued the amendment approving the LAR on January 28, 2010. Implementation is scheduled to begin in Spring 2011 following development of modification packages.

Unit 1	Spring 2011
Unit 3	Spring 2012
Unit 2	Fall 2013

Ronald A. Jones
Senior Vice President - Nuclear Operations

Ron Jones is senior vice president of nuclear operations for Duke Energy. He provides oversight for the safe and reliable operation of the three Duke Energy-operated nuclear stations – Catawba, McGuire and Oconee. He was named to his current position in January 2006. In addition to this role, Jones assumed responsibility for the nuclear fleet support and major projects organizations in February 2008.

Jones has more than 27 years experience in the nuclear field.

He joined Duke Power in 1980 as an engineer at Catawba Nuclear Station. He received his senior reactor operator license in 1987. After a series of promotions, he was named manager of maintenance engineering in 1988; superintendent of instrument and electrical in 1991; superintendent of operations at McGuire Nuclear Station in 1994; station manager of Catawba Nuclear Station in 1997; station manager of Oconee Nuclear Station in 2001; and vice president of Oconee Nuclear Station in 2002.

The (b)(6) graduated from Virginia Tech in Blacksburg, Va., with a Bachelor of Science degree in Electrical Engineering.

Jones is a member of the American Nuclear Society and the Institute of Electrical and Electronic Engineers; chairman of the Pressurized Water Reactors Owners Group Executive Management Group and Executive Committee; chairman of the Carolinas Nuclear Cluster; and an executive member of the Nuclear Energy Institute Nuclear Security and Workforce Working Groups. He is currently a member of the board of directors for Junior Achievement of the Central Carolinas and the Lake Norman Charter School.

(b)(6)

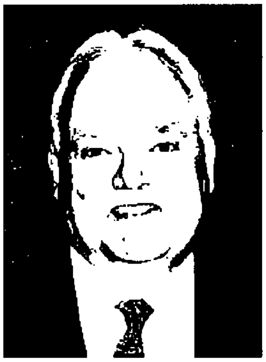
John W. (Bill) Pitesa

Senior Vice President – Nuclear Operations Oconee Nuclear Station Bill Pitesa is senior vice president of nuclear operations for Duke Energy. He provides oversight for the safe and reliable operation of Oconee Nuclear Station in Seneca, S.C. He is also responsible for the major projects groups and the fleet centers of excellence group. Bill Pitesa was named to his current position in January 2010.

Bill Pitesa has over 29 years of experience in the nuclear field. He joined the company in 1980 as an engineer at McGuire Nuclear Station. He was named senior reactor operator in 1986 and later served as a nuclear fuel handling supervisor and operations staff lead. In 1992, he served two years as a loaned employee for the Institute of Nuclear Power Operations.

Bill Pitesa returned to McGuire Nuclear Station in 1995 as an independent oversight manager and later moved to the corporate office as the nuclear operating experience manager. In 2000, he moved to Catawba Nuclear Station as an engineering supervisor. After a series of promotions, including operations training manager, Bill Pitesa was named as the station's operations manager in 2004 and station manager of Catawba Nuclear Station in 2005. In 2009, Bill Pitesa was named vice president of nuclear support for Duke Energy. He was responsible for corporate nuclear engineering, major projects, licensing and regulatory support, fleet outage management and other plant support functions.

Bill Pitesa earned a Bachelor of Science degree in electrical engineering from Auburn University. He is a registered professional engineer in North Carolina. In support of the International Atomic Energy Agency (IAEA) and the World Association of Nuclear Operators (WANO), Bill Pitesa has served on nuclear plant review teams in the United States, Korea, France, South Africa, and Ukraine.



David A. Baxter
Site Vice President
Oconee Nuclear Station

Dave Baxter is site vice president of Oconee Nuclear Station in Seneca, S.C. Baxter is responsible for the safe and reliable operation of Oconee Nuclear Station, a three-unit, pressurized water-reactor nuclear generating facility. He directs station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations.

Baxter has over 28 years of experience in nuclear engineering with Duke Energy.

Baxter joined the company in 1979 as a junior engineer at McGuire Nuclear Station in Huntersville, N.C. After a series of promotions at McGuire, including operations staff engineer, operations shift technical advisor, operations shift engineer and operations section manager, he was named nuclear engineering manager for modifications at Catawba Nuclear Station in 1998; and nuclear engineering manager for mechanical and civil engineering in 1999. He was named engineering division manager of Oconee Nuclear Station in 2002; and station manager in 2006. In that role, he was responsible for managing all aspects of Oconee's day-to-day operations. He was named to his current position in January 2008.

The (b)(6) earned a Bachelor of Science degree in Nuclear Engineering from Pennsylvania State University.

Baxter has received a U.S. Nuclear Regulatory Commission Senior Reactor Operator License and the Institute of Nuclear Power Operations' Senior Nuclear Plant Management Certification. He also served as a member of the B&W Owners Group Steering Committee. He is currently a board member of the Oconee Memorial Hospital Foundation and the United Way of Oconee County.

(b)(6)

Dhiaa M. Jamil
Group Executive and Chief Nuclear Officer

Dhiaa Jamil is Group Executive and Chief Nuclear Officer for Duke Energy. He is responsible for the safe and efficient operation of the company's three nuclear generating stations - Catawba, McGuire and Oconee nuclear stations. He was named to his current position in January 2008.

Mr. Jamil has more than 25 years of experience in the energy industry.

Most recently, Mr. Jamil served as Senior Vice President of nuclear support. He led the organization responsible for plant support, major projects and fuel management for Duke Energy's nuclear fleet. In addition, he was responsible for regulatory support, nuclear oversight and safety analysis functions. He joined Duke Power in 1981 as a design engineer in the design engineering department. After a series of promotions, he was named Electrical Systems Engineering Supervisor of Oconee Nuclear Station in 1989 and Electrical Systems Engineering Manager in 1994. He was named Maintenance Superintendent of McGuire Nuclear Station in 1997, Station Manager in 1999, and Site Vice President of McGuire Nuclear Station in 2002. In that role, Mr. Jamil was responsible for all aspects of the safe and efficient operation of the nuclear site. He was appointed Site Vice President of Catawba Nuclear Station in 2003.

Mr. Jamil received a Bachelor of Science degree in Electrical Engineering from the University of North Carolina at Charlotte.

He is a registered Professional Engineer in North Carolina and South Carolina. He has completed the Institute of Nuclear Power Operations (INPO) Senior Nuclear Plant Management course and received Duke Energy's technical nuclear certification. He has served as a senior member of the Institute of Electrical & Electronics Engineers (IEEE) and has completed a three-year assignment as a member of the Council of the National Academy for Nuclear Training. He is a former member of Dominion Energy Management Safety Review Advisory Committee, TVA Nuclear Safety Review Board, and Pacific Gas & Electric Nuclear Safety Oversight Committee. He also served on the board of directors of the York County, S.C. Chamber of Commerce.

Mr. Jamil is currently a member of the board of directors of the Charlotte Research Institute and serves on an advisory board for the School of Engineering at the University of South Carolina. He is a member of INPO's Executive Advisory Group, the Nuclear Energy Institute (NEI) New Plant Oversight Committee, and the NEI Nuclear Strategic Issues Advisory Committee Steering Group.

Benjamin C. (Ben) Waldrep
Vice President – Nuclear Centers of Excellence

Ben Waldrep is vice president of the nuclear centers of excellence for Duke Energy. He is responsible for improving fleet performance in operations, maintenance, work management, training, human performance/personal safety, and radiation protection/chemistry. Waldrep has more than 25 years of experience in the nuclear field. He joined Duke Energy in January 2010 from Progress Energy, where he served as vice president of Brunswick Nuclear Station. While at Progress Energy, he also served as plant manager at both the Brunswick and Harris nuclear stations. Prior to joining Progress Energy in 1999, Waldrep was employed by Florida Power and Light Co. in the engineering and maintenance department at Turkey Point Nuclear Station. The (b)(6) graduated from Georgia Tech in Atlanta with a Bachelor of Science degree in nuclear engineering and holds an MBA from the University of Phoenix. Waldrep is a member of the American Nuclear Society and has served on the Institute of Nuclear Power Operations (INPO) Academy Council. He (b)(6) and was a member of the Progress Energy Corporate Diversity Council. Waldrep was also a

(b)(6)

James R. (Jim) Morris
Site Vice President – Catawba Nuclear Station

Jim Morris is site vice president of Catawba Nuclear Station in York, South Carolina. Morris is responsible for the safe and efficient operation of Catawba Nuclear Station. He directs station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations. Most recently, Morris served as vice president of nuclear support for Duke Energy. Before joining the company in January 2005, Morris was vice president of support services for the Institute of Nuclear Power Operations (INPO) in Atlanta, Ga. INPO, sponsored by the nuclear industry, is an independent, nonprofit organization promoting the highest levels of safety, reliability and excellence in nuclear generation. He joined INPO in 1983, where he also served as vice president of plant operations, providing direction for operations, radiation protection and chemistry. Additionally, he participated in on-loan assignments including site vice president of Monticello, and at Brunswick and Pilgrim nuclear stations. The (b)(6) [redacted] graduated from the University of Missouri with a Bachelor of Arts degree in biology. He served in the U.S. Navy as a submarine officer from May 1976 to August 1983. Morris serves on the board of directors of the United Way of (b)(6) [redacted] (b)(6) [redacted]

Regis T. Repko
Site Vice President – McGuire Nuclear Station

Regis Repko is site vice president of McGuire Nuclear Station in Huntersville, N.C., for Duke Energy. He is responsible for the safe and efficient operation of McGuire Nuclear Station, a two-unit, pressurized, water-reactor nuclear generating facility. He directs station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations. Repko has 25 years experience in the nuclear energy field. He joined the company in 1985 as a junior engineer at Oconee Nuclear Station, located on Lake Keowee in Seneca, S.C. He was named engineer in operations in 1989; nuclear shift supervisor in August 1997; operations shift manager in December 1997; engineering supervisor in 2000; maintenance rotating equipment manager in March 2001; and superintendent of operations in October 2001, where he also had responsibility for the operations of Oconee Nuclear Station and Keowee Hydro Station. Repko was named engineering manager for Catawba Nuclear Station in April 2005 and station manager of McGuire Nuclear Station in January 2007. Repko was named site vice president of McGuire Nuclear Station in January 2010. The (b)(6) earned a bachelor of science degree in nuclear engineering from Pennsylvania State University. Repko also completed the Institute of Nuclear Power Operations (INPO) Senior Nuclear Plant Manager Course. He maintained a senior reactor operator license from the U.S. Nuclear Regulatory Commission for Oconee Nuclear Station from February 1992 to September 2000. Repko (b)(6)
(b)(6)

Briefing Sheet
Oconee Nuclear Station Drop In
Date: March 18, 2010

Current Plant Performance

- Units 1, 2 & 3 are in the Licensee Response Column of the NRC Action Matrix with no "Greater than Green" inspection findings or performance indicators for any unit. All Cornerstone objectives have been met.

- Substantive cross-cutting issue(s): None

Key Messages or Themes

- Quality and timeliness of engineering responses to plant and NRC issues continues to be a problem. Recent examples include the SSF letdown filter, 50.49 issues related to containment electrical penetrations, and freeze protection for the U2 SSF ASW pipe that was exposed during excavations for the tornado protection modifications. There have also been communication issues where engineering is not keeping senior management, including the engineering manager, informed of problems addressing the resident inspectors concerns and questions.

- Continue progress on major modifications. Delays have been encountered due to issues with the quality of Fluor work and productivity. Problems can also be partially attributed lack of oversight by Duke of Fluor work.

- Enhance communications with NRR staff. There is still a perception of some NRR staff that Duke is not serious about completing the major modifications associated with Tornado/HELB. Some of this perception is due to Duke not providing quality LARs and delaying submittal of other LARs (such as MSIVs).

Items of Interest

Organizational issues

- Oconee Organizational Chart - See attached

Plant equipment issues

- HELB/Tornado - LARs accepted (Rare Circumstances) and currently under NRR review. Tornado RAIs and HELB RAIs have been sent to licensee. Submittal is still not complete. Mitigating strategies require the installation of MSIVs. Analysis associated with the MSIVs has not been completed. Related modification inspection plan finalized and presented to RA on June 09, 2009.
- Digital RPS/ESPS - LAR accepted January 31, 2008. During the review of the LAR, the NRC staff generated numerous RAIs. The NRC issued the amendment approving the LAR on January 28, 2010. Implementation is scheduled to begin Spring 2011 for Unit 1 following development of modification packages (Unit 3 - Spring 2012, Unit 2 - Fall 2013). Inspection plan development and related augmented inspection training is necessary to support implementation inspections by DRS.

- NFPA 805 - The licensee submitted, as a supplement to the LAR, the fire probabilistic risk assessment model, change evaluations, and proposed modifications. NRR performed an audit in February 2009. The first set of RAIs were issued to the licensee on June 18, 2009, and responses were due to the NRC on August 3, 2009. The licensee is planning on submitting an additional LAR on April 15, 2010. Currently, DRS is needed to support LAR review and development of inspection plans/guidance (to include plan for disposition of identified deficiencies).

- Flood Action Plan - The NRC is evaluating an "inadequate protection" issue stemming from a past finding involving a breached flood barrier of the Oconee standby shutdown facility (SSF). By letter dated January 15, 2010, Duke submitted a letter to the NRC which provided its interim compensatory measures (ICMs) to ensure that the Oconee site will be adequately protected from external flooding events until the final mitigating strategies have been implemented and all site modifications have been completed. The NRC staff will perform a further review of the ICMs, and will perform a future inspection. The NRC also issued RAIs on January 29, 2010. Regional inspection of any related modifications is also anticipated.

Recent Plant Events

- During the Fall 2009 Unit 1 refueling outage, the licensee failed to recognize the significance of a visible gap between a fuel assembly and the core barrel following reload activities resulting in damage to multiple fuel assemblies. All but one was able to be removed from the core using standard refueling tools and was returned to the spent fuel pool. The remaining assembly required special tooling to be fabricated in order to be removed from the core and transported to the spent fuel pool. It is being disassembled and the fuel rods placed in a new cage structure for long term storage. Most of the disassembly/reassembly has been completed and the work is expected to complete during the upcoming Unit 2 refueling outage in the April – May 2010 time frame.

- Elevated levels of tritium have been detected in ground water monitoring wells within the Owner Controlled Area at the station. One of the wells exceeded the 20,000 pCi/l threshold which initiated the NEI Groundwater Communication plan on 2/9/10. The local media outlets carried the story for several days and additional interest may be fielded during the annual public meeting scheduled for April 8, 2010, at the Oconee World of Energy Visitors Center.

- During the Fall 2009 Unit 1 refueling outage, the SSF letdown line was tested for flow and found to have a blocked filter which prevented flow from being established. This line is required during an event designed to be mitigated by the use of the SSF and allows for RCS level in the pressurizer to be maintained. This issue is currently being reviewed and a Phase 3 package will be generated following testing the licensee has planned in March at Alden Labs in Massachusetts. It was subsequently determined that some flow blockage was present on Unit 2 and a power entry was made to remove the filter. Debris from a gasket in the valve just upstream of the filter was found on the Unit 2 letdown line filter similar in composition to what was found on the Unit 1 filter. The Unit 3 filter was then removed and debris was also found, although to a lesser degree.

- Discussions were held with the licensee On February 25, 2010, regarding the electrical penetrations in the East and West Penetration Rooms pertaining to compliance with 10 CFR 50.49, the modification process implementation and timeliness of corrective actions

taken to-date. Several issues were identified which the licensee took action to address including developing an operability determination on the penetrations based on a hybrid configuration that had been created through modifications to the penetrations and the timeliness of the corrective actions that have been open for 3+ years. An immediate determination of operability determined that all penetrations are currently operable. The Region and Headquarters discussed the issue and developed a series of questions that the licensee will be expected to address related to the penetrations on all three units. A prompt determination of operability was expected to be complete on March 12, 2010.

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Inspection findings
- None currently greater than Green

Allegations
- None noteworthy

Safety Culture/SCWE
- None

Security Issues
- None noteworthy

Significant industry issues
- None

Briefing Sheet
McGuire Nuclear Station Drop In
Date: March 18, 2010

Current Plant Performance

- Units 1 & 2 are in the Regulatory Response Column of the NRC Action Matrix with one White Violation and no "Greater than Green" performance indicators for either unit. All Cornerstone objectives have been met. 95001 for White finding completed on 3/9/2010 with acceptable results.

- Substantive cross-cutting issue(s): None

- Potential Status in Action Matrix: Following successful completion of 95001, both units should move to the Licensee Response Column of the NRC Action Matrix.

Key Messages or Themes

- Updated Final Safety Analysis Report (UFSAR) - The inspectors have found numerous inaccuracies and instances of incompleteness in the UFSAR over the past five years. The licensee has been performing an update project since 2006. The program has involved the use of contractors to date. Completion of the project will involve a transition to system engineers providing the final validation that the UFSAR is consistent with the content requirements identified in the licensee's commitment to RG 1.70. The Region decided at the EOC meeting to schedule a supplemental inspection using IP 92723 for three SL IV violations in the same traditional enforcement area (impeding the regulatory process). The inspection will likely happen this summer. DRP is waiting on input from the licensee on the best time for the inspection.

Items of Interest

Organizational issues

- Management Changes - Regis Repko succeeded Bruce Hamilton as Vice President, McGuire Nuclear Station effective January 1, 2010. Steven Capps became the Plant Manager at the same time. Clark Curry recently replaced Capps as the Engineering Manager. (see attached organizational chart)

Plant equipment issues

- Tritium - In response to the industry groundwater initiative, the licensee installed numerous monitoring wells with one monitoring well located near the licensee's final holdup pond indicating higher tritium levels (~11,000 pCi/l). The pond was drained and lined and well sample results have been trending down to ~5,000 pCi/l. A recent radiation protection TI inspection was completed that reviewed the licensee's response to the industry groundwater initiative and did not identify any concerns with the licensee's action in response to this initiative. With the exception of the final holdup pond well, tritium samples were found to be the same as in the lake (~1,500 pCi/l).

- National Fire Protection Agency (NFPA) 805 - McGuire is in its 3rd year of transitioning to NFPA 805. Triennial Fire Protection Inspection 71111.05P was completed in 2009 and

the License Amendment Request is scheduled to be submitted by 2011, 6 months after Oconee LAR is approved. Oconee and Catawba are also transitioning, with projected completion in 2010 and 2012 respectively.

Recent Plant Events

None Noteworthy

Inspection findings

- White Finding related to Nuclear Service Water (RN) Strainer Fouling - On August 6, 2007, the licensee identified that the procedures for performing a manual backwash of the RN strainers (installed immediately upstream of the RN pumps) directed operators to use the non-seismically qualified, non-safety-related instrument air (VI) system to manipulate the valves required for the manual backwash function. The backwash procedures were written as part of a late 2003 plant modification to upgrade and reclassify the RN filtering and backwash functions to "safety-related," in response to NRC concerns of increased Alewife fish concentrations in Lake Norman that could cause the loss of nuclear service water pumps. In addition to the reliance on non-safety-related VI, this modification also relied on other non-safety-related instrumentation and components for performing safety-related backwashes, including the UFSAR-credited differential pressure instrument. As such, strainer backwashes could not readily be accomplished upon: (1) a loss of coolant accident (due to isolation of VI to backwash discharge valves from an SI signal); (2) a loss of offsite power when diesel driven VI compressors are not available (due to a loss of power to the motor driven VI compressors); or (3) a loss of VI (due to a VI pipe break/leak). The licensee immediately installed a temporary modification to restore safety-related manual backwash capability when RN is aligned to the low level intake and backwash is discharged to the ground water sump system. The licensee originally committed to submitting a license amendment request to address backwash system design changes necessary to resolve identified deficiencies related to discharging to the condenser circulating water header, however the licensee has not yet determined whether that will be done. McGuire Units 1 and 2 have been in the Regulatory Response column since the 3rd quarter of 2008 due to this White Finding. The associated 95001 supplemental inspection was completed on March 9, 2010.

Allegations

- None noteworthy

Safety Culture/SCWE

- None

Security Issues

- None noteworthy

Significant industry issues

- None

Briefing Sheet
Catawba Nuclear Station Drop In
Date: March 18, 2010

Current Plant Performance

- Units 1 & 2 are in the Licensee Response Column of the NRC Action Matrix with no "Greater than Green" inspection findings or performance indicators for either unit. All Cornerstone objectives have been met.
- Substantive cross-cutting issue(s): None

Key Messages or Themes

- The licensee has had a number of security related issues over the last 6 months which included two instances of guards leaving their weapons unattended, an inadequate search at the PAP, several issues with weapon sights out of adjustment, and a late report to the NRC concerning a degraded intrusion detection system (IDS). The DRS annual security baseline inspection conducted in January exited with 2 licensee identified violations, one NRC identified NCV and one URI related to these issues. The licensee has initiated an adverse trend PIP to address the declining security performance.
- The licensee was proactive and diligent in locating a small RCS leak inside containment (approximately 0.01 gpm) in January, shortly after returning to power following 1EOC18. The leak was first indicated by an increase in count rates on the containment air particulate monitor and an increase in the B containment floor and equipment drain sump level. The licensee organized a team to systematically assess and locate the source of the leak. Through the use of boroscope cameras and a robotic camera, the licensee was able to locate the leak on the A hot leg which was located under the insulation. The licensee made an appropriately conservative decision to shut down the unit to definitively identify the leak source and repair the leak. The leak source was determined to be from a wide range T_{hot} RTD thermowell seal weld.

Items of Interest

Organizational issues

- Management Changes - George Hamrick, former Engineering Manager at Catawba, assumed the role of Station Manager. Tom Ray, former Maintenance Superintendent was named as Engineering Manager. (see attached organizational chart)
- William States Lee III Nuclear Station - Duke Energy submitted a 10 CFR 52 application for a combined operating licensee (COL) to the NRC on December 13, 2007, which was docketed on February 25, 2008. A public scoping meeting was also held on May 1, 2008 near the proposed plant site. The license application references the Westinghouse AP1000 pressurized water reactor as the reactor type and intends to construct two reactors on this site. The location is just south of the North Carolina/South Carolina border near Gaffney, S.C.

Plant equipment issues

- Groundwater Tritium - On October 8, 2007, elevated levels of tritium were detected in one of the newly-installed ground water monitoring wells within Catawba's Protected Area. Measured levels were approximately twice the Environmental Protection Agency (EPA) limit for drinking water (~42,000 pCi/L vs. 20,000 pCi/L). The State of South Carolina and the NRC were notified as required by the Nuclear Energy Institute's Groundwater Monitoring Initiative communication plan. Additional sampling was performed by the licensee (within the Owner Controlled Area) and by the South Carolina Department of Health and Environmental Control (SC DHEC) in off-site wells with no additional samples showing values approaching the EPA limit. A public meeting was held near the plant on December 6, 2007, to discuss the issue and answer questions from local residents. In November 2008, results from the on-site groundwater monitoring wells revealed an increase in the tritium levels in well C213 (the one that initially exceeded the EPA limit). The measured value had increased from 25,400 pCi/L in June to 45,400 pCi/L in the September 2009 sample. The state was notified and an additional sample was taken for analysis. The licensee has continued quarterly sampling for tritium at 42 onsite wells since the initial reporting. Currently (November 2009 sample) all wells are below the EPA drinking water limits except for well C213 which remains elevated at 47,400 pCi/L.

- Service Water Systems Performance Improvement Initiative - Catawba is in the process of implementing a major, long-term initiative to maintain the integrity of the plant systems, which transport lake water into and out of the plant for cooling components and other systems within the Auxiliary, Reactor, Service and Turbine buildings. Due to the aggressive properties of the water in Lake Wylie, the licensee is in the process of cleaning/coating the large bore header piping (A header completed on February 27 and B header to commence March 14), and replacing small bore buried piping with high density polyethylene pipe. Installation of a chlorination/de-chlorination system is complete.

- 1A Reactor Coolant Pump #2 Seal Leakage - The licensee shut down Unit 1 two weeks early in November 2009 to commence 1EOC18 due to excessive leakage of the 1A Reactor Coolant Pump (NCP) #2 seal which reached the operational limit of 1.2 gpm. The licensee replaced all four NCP seal packages during the outage. Initial indication of the leakage was due to a score in the seal face. The licensee is working with the vendor to complete the root cause.

- Unit 1 A Hot Leg RTD Thermowell Seal Weld Leak - The licensee shut down Unit 1 in February 2010 due to potential pressure boundary leakage that was subsequently confirmed to be from a wide range T_{hot} RTD thermowell seal weld. The thermowell was threaded to provide a mechanical attachment to the hot leg for structural integrity, with the seal weld providing a leak tight barrier. The licensee made a 10 CFR 50.72 8-hour notification for a degraded RCS barrier. The seal weld was original to construction. Three other similar seal welds were inspected with no issues. The licensee is currently performing a root cause investigation of the issue.

Recent Plant Events

- Unit 1 shut down in February 2010 due to pressure boundary leakage.

Inspection findings
- None noteworthy

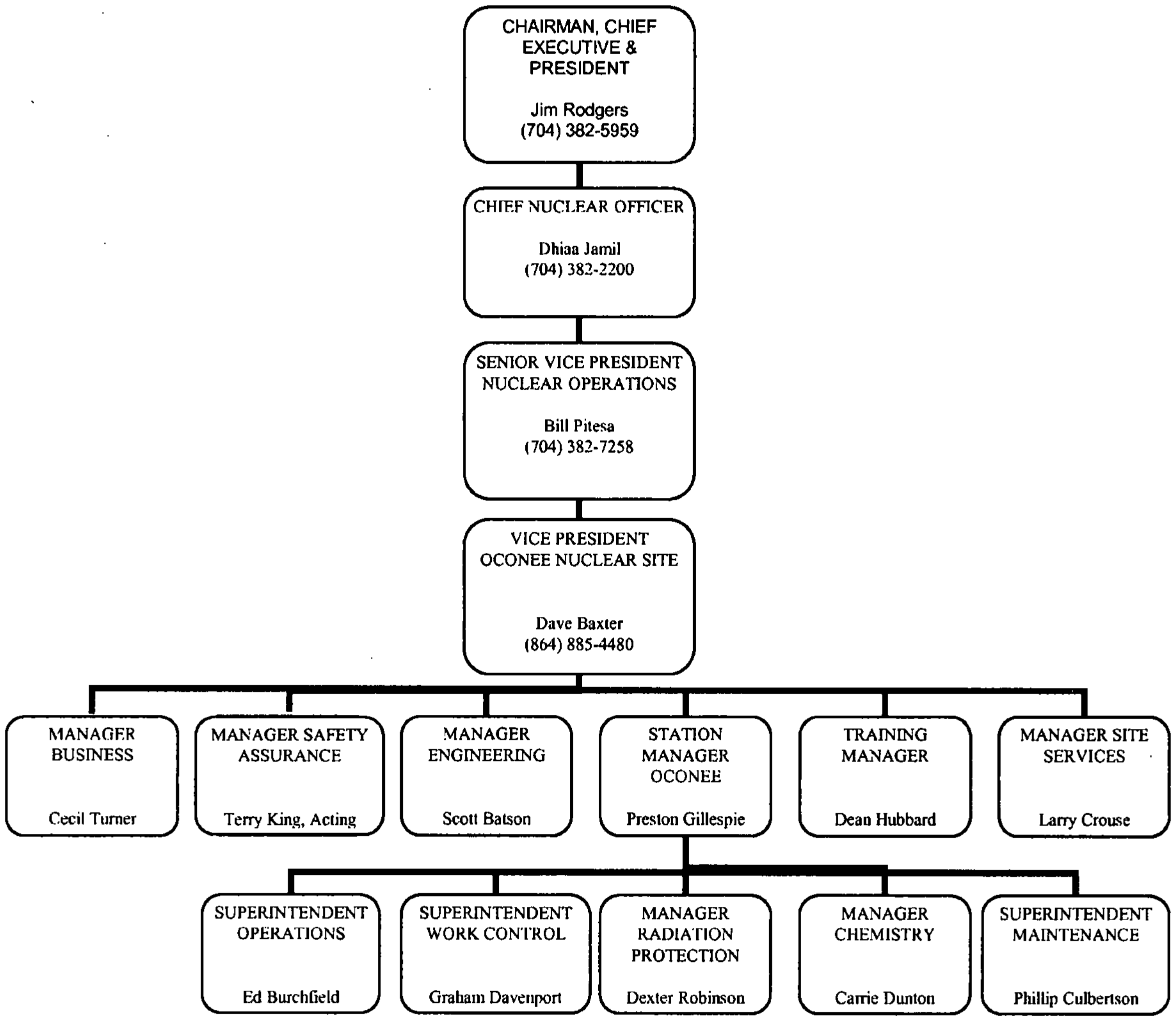
Allegations
- None noteworthy

Safety Culture/SCWE
- None

Security Issues
- Licensee made a 10 CFR 73.71 notification in January 2010 for degraded IDS due to a computer malfunction. Report was determined not to be timely by DRS security team inspection.

Significant industry issues
- None

DUKE ENERGY CORPORATION
OCONEE NUCLEAR STATION UNITS 1, 2, & 3



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          - MANAGER RADIATION PROTECTION – Joe Smith
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- MANAGER BUSINESS – Curt Helmers

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DUKE ENERGY CORPORATION
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U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

BRIEFING BOOK

FOR

COMMISSIONER GEORGE APOSTOLAKIS

OCONEE NUCLEAR STATION

September 13, 2011

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TAB 1

Agenda for Commissioner Apostolakis's Visit to Oconee Nuclear Station

September 13, 2011

7:30 a.m.	Leave the hotel for Oconee Nuclear Station. (See map and directions in Tab 2)
8:15 a.m.	Arrive at the World of Energy visitors center for overview discussion of the Keowee-Toxaway Project
8:30 a.m.	Depart the World of Energy for the Jocasse Hydro-Electric Facility
9:15 a.m.	Arrive at the Jocasse Hydro-Electric Facility for tour of powerhouse and dam structure
11:00 a.m.	Depart the Jocasse Hydro-Electric Facility for the Oconee Nuclear Station
11:45 a.m.	Arrive at Oconee, process into the Protected Area (Note: The Senior Resident Inspector will be the assigned escort)
11:55 a.m.	Meet with the Oconee Resident Office staff
12:15 p.m.	Working lunch with the station staff
1:15 p.m.	Tour of the Protected Area
3:00 p.m.	Tour the Keowee Hydro Facility and the current / planned external flood protection modifications
4:00 p.m.	Meeting with Duke management & supervisors on industry and regulatory issues
5:00 p.m.	Depart for Greenville-Spartanburg airport

Executive Summary

Purpose of the visit/meeting
- Meet the Oconee Resident office staff.
- Meet the Oconee senior management team
- Tour the Jocasse Hydro Facility
- Tour the Keowee Hydro Facility
- Tour portions of the plant including ongoing tornado and HELB modifications.
- Tour the Unit 1 / Unit 2 Main Control Room including the new digital RPS/ES equipment installed during the Spring 2011 refueling outage

Issues to be addressed (See TAB 6)
- External flooding
- NFPA 805 transition
- Tornado and HELB mitigation
- Digital Reactor Protective System / Engineered Safeguards Protective system project

Persons to meet

Oconee Personnel (See TAB 8)
- Bill Pitesa, Senior Vice President
- Richard Freudenberger, Manager, Regulatory Interface (ONS)
- Preston Gillespie, Site Vice President
- Scott Batson, Station Manager
- Bob Guy, Organizational Effectiveness Manager
- Tom Ray, Engineering Manager
- Terry Patterson, Safety Assurance Manager

Region II Personnel (See TAB 9)
- Jonathan Bartley, Chief, Reactor Projects Branch 1
- Andy Sabisch, Senior Resident Inspector
- Kevin Ellis, Resident Inspector
- Geoffrey Ottenberg, Resident Inspector

Activities on site
- Meet with Resident office staff
- Working lunch with Oconee staff including a question-&-answer session
- Meeting with the Duke management team to discuss plant, corporate and industry issues
- Plant tour with the resident inspectors, licensee, and
- Tour the Jocasse and Keowee hydro facilities

Messages to be communicated (Reference TAB 6)
- Continue to focus on safe plant operation
- Important to keep Tornado/HELB modifications on track

- Recognize the challenge of managing multiple major projects
- Seek opportunities to modify schedule based on risk reduction

Licensee's briefing topics

- The Duke Fleet is implementing actions to improve corporate governance and oversight
- Oconee Performance and Direction
- Major investments to enhance safety, improve reliability, resolve licensing basis issues, and reduce overall station risk profile are continuing.

Licensee Ownership Information

Duke Energy Carolinas owns and operates the three-unit Oconee Nuclear Station located near Seneca, SC and the two-unit McGuire Nuclear Station located near Huntersville, NC. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station located in York, SC.

Recent Oconee Management Changes (Reference TAB 7)

The following management changes have been implemented over the past six months:

- Bob Guy was named as Manager, Organizational Effectiveness, Oconee Nuclear Station.
- Rich Freudenberger was reassigned from the Safety Assurance Manager position to Manager, Regulatory Interface. In this role he is responsible for management of site programs and processes related to regulatory compliance.

ROP Assessment - Significant ROP Inspection Findings (Reference TAB 5)

A Special Inspection was initiated when the licensee identified that the breakers for pressurizer heaters powered from the SSF could trip prematurely. As a result of the inspection, three potentially greater than Green findings were identified for failing to maintain design control of SSF components and failing to perform adequate operability evaluations.

Potential Discussion Topics (Reference TAB 6)

External Flood Action Plan

An issue related to the potential impact that external flooding would have on the Oconee Nuclear Station is currently being addressed by both the licensee and NRC. The licensee has developed Interim Compensatory Measures (ICMs) to address the external flooding concerns and is working on permanent actions to ensure the station is not adversely affected by a potential external flooding scenario. A Confirmatory Action Letter (CAL) was issued on June 22, 2010, to confirm that the ICMs would remain in place until final modifications have been completed. The CAL also requested the licensee to provide a list of modifications to enhance the capability of the Oconee Nuclear Station to withstand the postulated failure of the Jocassee Dam. By letter dated April 30, 2011, the licensee responded to that CAL request. The NRC staff has reviewed the licensee's response, and by letter dated August 18, 2011, requested the licensee to provide clarifying information.

NFPA 805 Transition

Oconee is one of two pilot plants that are in the process of transitioning to NFPA 805 for fire protection. The NRC staff completed its review of the License Amendment Requests (LAR) and issued the final licensee amendment on December 29, 2010. The licensee is currently performing modifications to be in compliance with NFPA 805.

Tornado & High Energy Line Break (HELB) Mitigation

The licensee is implementing a number of major modifications designed to minimize the risk exposure resulting from events such as tornado and a high-energy line break. The licensee submitted several LARs to update the Updated Final Safety Analysis Report (UFSAR). The staff has issued numerous Requests for Additional Information and the licensee is in the process of responding to the request.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)

The licensee is currently implementing a major modification to all three units' Reactor Protection System and Engineered Safeguards Features Actuation System (RPS/ESFAS). The licensee has installed the new digital system on Unit 1 (performed during the Spring 2011 refueling outage) and is preparing to install the system on Unit 3 in the Spring 2012 outage followed by Unit 2 in the Spring of 2013.

William States Lee III Nuclear Station Combined Operating License (COL) Application

The licensee submitted a 10 CFR 52 application for a combined operating licensee to the NRC on December 12, 2007, which was docketed on February 25, 2008. This project is on the site of the old Cherokee Nuclear Station project that was cancelled in the 1980's.

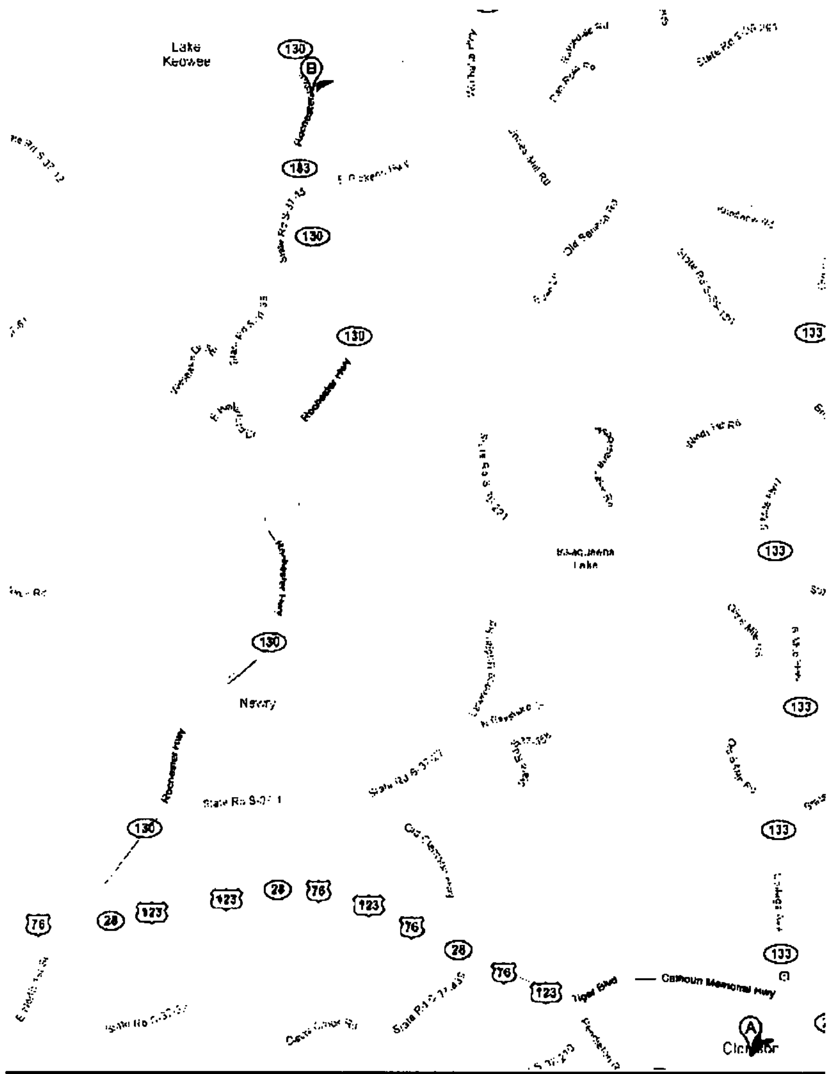
Tritium

Elevated levels of tritium have been detected in a single ground water monitoring well within the Owner Controlled Area.

TAB 2

Facility Location Map and Directions

Directions to Oconee Nuclear Station from Clemson, SC



1. Head north on College Ave toward Earle St — 0.6 mi
2. Turn left onto S Carolina 28 W/US-123 S/US-76 W/Tiger Blvd — 6.2 mi
   Continue to follow S Carolina 28 W/US-123 S/US-76 W
3. Turn right onto S Carolina 130 N/Rochester Hwy — 7.8 mi
   Destination will be on the right approximately 0.5 miles past the traffic light at junction SC HWY 183

The Resident Inspector office number is 864-882-6927.

TAB 3

Facility Data

Utility: Duke Energy Carolinas, LLC
Location: 8 miles northeast of Seneca, SC
County: Oconee County, SC

	UNIT 1	UNIT 2	UNIT 3
Docket Nos.	50-269	50-270	50-287
License Nos.	DPR-38	DPR-47	DPR-55
Full Power License Date	02/06/1973	10/06/1973	07/19/1974
Commercial Operation Date	07/15/1973	09/09/1974	12/16/1974
OL Expiration Date	02/06/2033	10/06/2033	07/19/2034

PLANT CHARACTERISTICS	All Units
Reactor Type	PWR
Containment Type	Dry Ambient
Power Level	2568 MWt (900 MWe)
NSSS Vendor	B & W

TAB 4

Facility Unique Features

Emergency Supply to 4160 Volt-AC Safety-Related Buses

Power to the safety-related buses is provided from the two Keowee Hydro Station generating units. A single Keowee Hydro Unit (KHU) will supply all emergency power. This power is supplied to Oconee by two connections; an overhead transmission line and an underground line. Gas turbines at the Lee Steam Station can also be made available manually via a separate overhead line to provide power if neither KHU is available.

Standby Shutdown Facility (SSF)

The SSF provides an alternate and independent means to achieve and maintain a hot standby condition for all three units following postulated turbine building flood, fire, and sabotage events. It consists mainly of one diesel generator, an auxiliary service water pump, and supporting equipment (in a seismically qualified building) and three standby makeup pumps (one in each unit's reactor building). Powered by the SSF diesel generator, the standby makeup pumps deliver water at approximately 26 gpm from the associated spent fuel pool to the reactor coolant pump seals. In support of primary decay heat removal, the SSF auxiliary service water pump supplies water from the condenser circulating water (CCW) system to the once-through steam generators. The SSF is able to maintain all three units in Mode 3 (525 degrees) for 72 hours. The proposed Tornado/HELB mitigation strategies also take credit for the SSF.

Low Pressure Service Water (LPSW)

As originally designed, long-term decay heat removal has relied on the non-safety, non-seismically qualified CCW piping system and its pumps to provide water to the safety-related LPSW pumps located in the turbine building basement. During loss of offsite power events, the CCW pumps lose power; therefore, decay heat removal and cooling water for safety-related pumps rely on the use of a siphon effect (between the lake and the CCW system) to provide water to the safety-related LPSW system.

Emergency Feedwater (EFW)

The safety-related EFW pumps (two per unit) are located in the turbine building basement. Each unit's EFW system must rely on the limited source of water in its seismically qualified upper surge tank and on the water contained in the condenser hotwell. However, cross-connect valves are provided between all three units' EFW systems. Identified EFW single failure vulnerabilities have been addressed through plant modifications and licensing basis changes/clarifications.

Containment Isolation

Several piping systems penetrating containment were designed without isolation valves (Main Steam), or redundant, reliable (QA-1) isolation devices (Main Feedwater). In 2002, a new automatic feedwater isolation system (AFIS) modification was installed that secures/isolates both main and emergency feedwater to the affected steam generator. Supplemental diesel air compressors are used to compensate for the expected bleed off of valve operating air pressure should a coincident loss of offsite power occur.

Reactor Oversight Process Info

The following URLs are for the Oconee Nuclear Station (Units 1, 2 and 3) ROP Performance Summary web pages.

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO1/oco1_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO2/oco2_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO3/oco3_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/pi_summary.html

ROP Performance Status (3rd Quarter 2010 – 2nd Quarter 2011)

The licensee was in the Degraded Cornerstone Column of the NRC's Action Matrix due to a Yellow finding and a White finding related to blockage in the Standby Shutdown Facility (SSF) letdown lines for all three units. A 95002 supplemental inspection was performed in December 2010 and both findings were closed. The licensee moved to the Licensee Response Column of the NRC's Action Matrix in January 2011. There were no safety significant findings in the first or second quarter 2011. On July 5, 2011, a Special Inspection was initiated when the licensee identified that the breakers for pressurizer heaters powered from the SSF could trip prematurely. As a result of the inspection, three potentially greater than Green findings were identified for failing to maintain design control of SSF components and failing to perform adequate operability evaluations. These finding are currently being evaluted to determine their safety significance.

TAB 6

Current Issues

A. EXPECTED DISCUSSION TOPICS

External Flood

An issue related to the potential impact that external flooding would have on the Oconee Nuclear Station has been raised and is currently being addressed by both the licensee and NRC. The licensee has developed Interim Compensatory Measures to address the dam concerns and is working on permanent actions to ensure the station is not adversely affected by potential external flooding. Regional inspection of the Interim Compensatory Measures was completed in June 2010. On June 22, 2010, the NRC issued a CAL which documented that the licensee would submit a final inundation study by August 2, 2010 (completed), submit a list of modifications by November 30, 2010 (licensee extended until April 2011), and complete those modifications by November 30, 2011.

Tornado & HELB Mitigation

As a result of a 95002 supplemental inspection of two White Mitigating System tornado-related findings in 2001, it was determined that Oconee has a number of tornado-related vulnerabilities that collectively represented a deficient tornado mitigation strategy. Duke notified the NRC in January 1999 that it was initiating a project to reconstitute the design and licensing basis for HELBs outside the reactor building. The licensee is implementing a number of major modifications designed to minimize the risk exposure resulting from events such as tornado and a high-energy line break, as well as add equipment that had not been part of Oconee's initial design; i.e., main steam isolation valves. The schedule for completion of these activities has been adversely impacted by factors including changes to the design as work is proceeding, quality issues tied to the vendors performing the work, and fabrication issues. The licensee submitted LAR's to update the UFSAR in June 2009.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)

The licensee is currently implementing a major modification to all three units' Reactor Protection System and Engineered Safeguards Features Actuation System (RPS/ESFAS). The licensee has installed the new digital system on Unit 1 (performed during the Spring 2011 refueling outage) and is preparing to install the system on Unit 3 in the Spring 2012 outage followed by Unit 2 in the Spring of 2013. The Division of Reactor Safety is currently leading the NRC inspection effort supported by the resident inspectors.

William States Lee III Nuclear Station Combined Operating License (COL) Application

By letter dated December 12, 2007, Duke Energy Carolinas, LLC (Duke) tendered a COL application for two Westinghouse AP1000 advanced passive pressurized water reactors

designated as Units 1 and 2 of the William States Lee III Nuclear Station. The proposed site is located in the eastern portion of Cherokee County in north central South Carolina, approximately 35 miles southwest of Charlotte, North Carolina, and approximately 7.5 miles southeast of Gaffney, South Carolina.

Tritium

Elevated levels of tritium have been detected in a ground water monitoring well within the Owner Controlled Area. In February 2010, one well exceeded the 20,000 pCi/l threshold which initiated the NEI Groundwater Communication plan. The local media outlets carried the story for several days and additional interest was indicated during the annual public meeting for 2009. The licensee has installed additional monitoring wells and is conducting sampling & analysis to determine if the source is an active leak or a legacy issue. The latest sample values indicate that the tritium levels in the well has decreased below the 20,000 pCi/l threshold.

B. OTHER TOPICS OF INTEREST

Labor/Management Issues

None

License Renewal Activities

The Oconee Site-Specific Independent Spent Fuel Storage Installation (ISFSI) license was renewed on May 29, 2009, for 40 additional years. This included a 20 year renewal plus an exemption which allows for an additional 20 years. The license will now expire on January 31, 2050.

Escalated Enforcement, Non-Green Findings and Non-Green Performance Indicators

- A licensee-identified potentially greater than Green apparent violation of 10 CFR 50 Appendix B, Criterion III, Design Control, was identified when the licensee failed to maintain design control of the Standby Shutdown Facility (SSF). The failure to maintain equipment qualification did not provide reasonable assurance that the SSF auxiliary service water (ASW) subsystem would perform its safety function.

- An NRC-identified potentially greater than Green apparent violation of 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures, and Drawings, was identified when the licensee failed to perform an adequate operability evaluation for the Standby Shutdown Facility (SSF) auxiliary service water subsystem in accordance with NSD 203, Operability/Functionality. The licensee failed to assure the SSF pressurizer heater breakers would function under expected environmental conditions before declaring the SSF operable but degraded/nonconforming.

- An NRC-identified potentially greater than Green apparent violation of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, was identified when the licensee

failed to perform a 50.59 evaluation for a compensatory measure for the SSF ASW subsystem in accordance with NSD 203, Operability/Functionality. The revised guidance to use solid-water operation for RCS pressure control could not be used as a compensatory measure without prior NRC review and approval.

Open Investigations

There are two open OI investigations.

Open Allegations

There are three open allegations related to cyber security and access control

Congressional Interest

None

Harassment and Intimidation Issues

None

2.206 Petitions

None

Recent News Articles

(b)(4)

(b)(4)

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(b)(4)

(b)(4)

TAB 7

Facility Organization

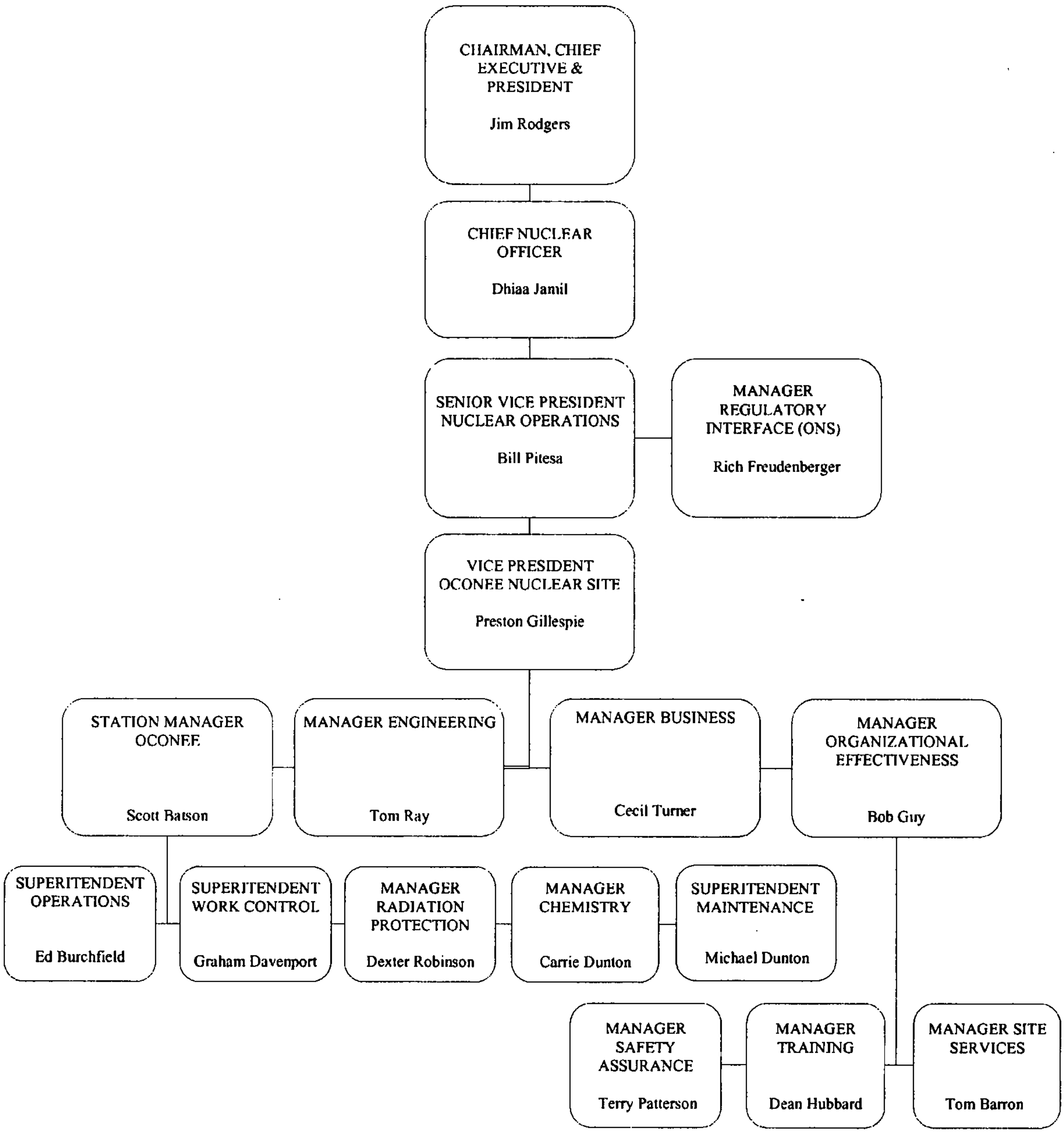
OVERVIEW OF DUKE ENERGY

Duke Energy Carolinas

Duke Energy Carolinas operations include nuclear, coal-fired, natural gas, and hydroelectric generation. This diverse fuel mix provides nearly 21,000 megawatts (MW) of electricity to more than 2.3 million electric customers in a 24,000 square-mile service area of North Carolina and South Carolina. Duke Energy Carolinas generates energy primarily from three nuclear generating stations with a combined net capacity of 6,996 MW, eight coal-fired stations with a combined capacity of 7,699 MW, 31 hydroelectric stations with a combined capacity of 2,693 MW, and six combustion turbine stations with a combined capacity of 2,861 MW. Duke Energy Carolinas owns and operates the two-unit McGuire and the three-unit Oconee nuclear stations. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station.

Duke Energy submitted a 10 CFR 52 application for a combined operating licensee to the NRC on December 13, 2007, which was docketed on February 25, 2008. A public scoping meeting was also held on May 1, 2008, near the proposed site location. The license application references the Westinghouse AP1000 as the reactor type and two reactors are planned for the site. The location is just south of the North Carolina/South Carolina border near Gaffney, S.C.

DUKE ENERGY
OCONEE NUCLEAR STATION
ORGANIZATIONAL CHART



Biographical Data of Principal Managers

John W. (Bill) Pitesa
Senior Vice President – Nuclear Operations

Bill provides oversight for the safe and reliable operation of all three Duke operating nuclear stations. He is also responsible for the major projects groups and the fleet centers of excellence group. Bill was named to his current position in December 2010. Bill has over 29 years of experience in the nuclear field.

Bill joined the company in 1980 as an engineer at McGuire Nuclear Station. He was named senior reactor operator in 1986 and later served as a nuclear fuel handling supervisor and operations staff lead. In 1992, he served two years as a loaned employee for the Institute of Nuclear Power Operations.

Bill returned to McGuire Nuclear Station in 1995 as an independent oversight manager. In 2000, he moved to Catawba Nuclear Station as an engineering supervisor. After a series of promotions, including operations training manager, Bill was named as the station's operations manager in 2004 and station manager in 2005. In 2009, Bill was named vice president of nuclear support for Duke Energy. He was responsible for corporate nuclear engineering, major projects, licensing and regulatory support, fleet outage management and other plant support functions.

Bill earned a Bachelor of Science degree in electrical engineering from Auburn University. He is a registered professional engineer in North Carolina. In support of the International Atomic Energy Agency (IAEA) and the World Association of Nuclear Operators (WANO), Bill has served on nuclear plant review teams in the United States, Korea, France, South Africa, and Ukraine.

T. Preston Gillespie Jr.
Site Vice President - Oconee Nuclear Station

Preston is responsible for the safe and reliable operation of Oconee Nuclear Station, a three-unit, pressurized water-reactor nuclear generating facility. He directs station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations. He joined Duke Power in 1986 as an assistant engineer at Oconee Nuclear Station. He served in a variety of positions while at the station, including nuclear operations shift manager, shift operations manager, and nuclear engineering manager. He moved to Catawba Nuclear Station in 2007 to serve as the station's operations superintendent. He was named Oconee Station Manager in October 2008 and moved to his current position in December 2010.

Preston graduated from Clemson University with a Bachelor of Science degree in mechanical engineering. He is a registered professional engineer in South Carolina. He held a senior reactor operator license at Oconee Nuclear Station. He is also a past recipient of the company's Robinson Award, which recognized employees for their outstanding contributions to the company's operations.

Robert (Bob) H. Guy
Organizational Effectiveness Manager

Bob is responsible for managing station support functions including training, site services, security, emergency preparedness, performance improvement, environmental and safety, and regulatory compliance. Bob joined Duke Energy in May 2011.
Prior to joining Duke Energy, Bob had over thirty years of experience in military, government and commercial nuclear fields. Guy trained in nuclear power after graduating from the Naval Academy. He served in a variety of positions on several submarines including supervision of the nuclear propulsion department. Other assignments included operations training instructor and training manager at the Nuclear Power Training Unit Idaho Falls, on the staff of the Director of Naval Reactors and overseas duty in Australia and Japan. He commanded the nuclear submarine USS Greeneville (SSN 772) from 1996 to 1999, commanded Naval Nuclear Power Training Unit Charleston from 2002 to 2006 and Naval Nuclear Power Training Command from 2006 to 2007. After retiring from the Navy, he served as a Nuclear Safety Specialist in the Office of Independent Oversight, U.S. Department of Energy and was later employed as Manager of Nuclear Oversight, Salem Nuclear Generating Station with PSEG Nuclear.

Bob earned a Bachelor of Science degree in Marine Engineering from the United States Naval Academy.

Scott L. Batson
Station Manager

Scott is responsible for all aspects of operation, maintenance, work control, radiation protection, and chemistry activities at the station to provide safe, reliable, and efficient electrical service. He has over 22 years of experience in plant operation and engineering. He joined the company in January 1985 as a junior engineer at Oconee Nuclear Station in and has held various positions including most recently as Operations Superintendent responsible for managing all aspects of operations activities at Oconee and at Keowee Hydro Station. He was named Engineering Manager in January 2008 and moved to his current position in December 2010.

Scott earned a Bachelor of Science degree in Mechanical Engineering from Clemson University and is a registered professional engineer in South Carolina. He received a senior reactor operator license from the U.S. Nuclear Regulatory Commission and a senior nuclear plant management certification from the Institute of Nuclear Power Operations. He has also completed the Duke Energy Advanced Leadership Program.

Thomas (Tom) D. Ray
Engineering Manager

Tom is responsible for managing and directing activities at the station related to system, component, and design engineering. He joined the company in 1989 as an associate engineer in the nuclear generation department in Charlotte. He was named senior engineer of reactor engineering at McGuire Nuclear Station in 1994; engineering supervisor in 1999; maintenance manager in 2002; and outage manager in 2003. He was named safety assurance manager at Catawba Nuclear Station in 2004, maintenance superintendent in 2005, and most recently engineering manager. Ray was named engineering manager of Oconee Nuclear Station in September 2010. Before joining the company, Ray was an engineer for Bechtel Power Corporation, from 1987 to 1989.

Ray earned a Bachelor of Science degree in nuclear engineering from North Carolina State University. He is a registered professional engineer in North Carolina and has a technical nuclear certification. He also serves as a Duke Energy management committee representative for the Pressurized Water Reactor Owners Group.

Terry L. Patterson
Safety Assurance Manager – Oconee Nuclear Station

Terry is responsible for the management of site programs and processes related to environmental health and safety, regulatory compliance, performance improvement, emergency planning and security. He filled this position in October 2010 coming from Constellation Energy Nuclear Group (CENG). Terry has over 30 years of commercial nuclear power experience. Prior to joining Duke Power, Terry spent five years in the nuclear submarine service where he served as the Main Propulsion Assistant on a nuclear ballistic missile submarine. He also spent three years with Combustion Engineering, Inc., fifteen years at Omaha Public Power District's (OPPD) Fort Calhoun Station and thirteen years at Florida Power and Light's (FPL) St. Lucie Nuclear Station.

Terry earned a Bachelor of Science degree in Physics from the U. S. Naval Academy, Annapolis, Maryland and a Masters in Business Administration from the University of Nebraska.

Richard (Rich) J. Freudenberger
Nuclear Regulatory Support Manager – Oconee Nuclear Station

Rich is responsible for the management of site programs and processes related to regulatory compliance and licensing. He was named to his current position in February 2010. Previously, Rich served as safety assurance manager of Oconee Nuclear Station since 2008. He was responsible for the management of site programs and processes related to environmental health and safety, regulatory compliance, performance improvement, emergency planning and security. Prior to joining Duke Power in 1997, Rich had 12 years of commercial nuclear power experience as a resident and senior resident inspector for the Nuclear Regulatory Commission at the Maine Yankee, Crystal River, and Catawba nuclear stations. His first position with Duke Power was as the regulatory audit supervisor. He was responsible for implementation of performance-based audits required by the Duke Energy Nuclear Quality Assurance program. In February 2000, Rich was assigned to the Oconee Nuclear Station as the secondary systems engineering supervisor and was responsible for the power conversion and standby shutdown systems mechanical design and licensing basis, testing support and equipment reliability. Between 2001 and 2007, he held several other supervisory positions within engineering. He successfully completed the operator training program and was licensed as a senior reactor operator in July 2004.

Rich earned a bachelor of science degree in marine engineering from the Maine Maritime Academy in Castine, Maine.

TAB 9

Resumes of Oconee Resident Inspectors

Andrew *(Andy) T. Sabisch
Senior Resident Inspector

Andy joined the NRC in 2003. He is a (b)(6) (b)(6) Mr. Sabisch attended SUNY Maritime College and received his Bachelor degree in Nuclear Science with a minor in Computer Science.

Andy joined MetEd at the Three Mile Island Generating Station in Middletown, PA and worked in both the Operations department and the Unit 1 Recovery Group. He served as Shift Test Director in 1982 during hot functional testing conducted to support the restart of Unit 1 following the 1979 Unit 2 accident. Andy worked for Louisiana Power & Light from 1982 to 1984 as a Plant Engineering section manager supporting the construction and turnover of plant systems during startup of the Waterford 3 Steam Electric Station. In this role, he also was responsible for the development of the plant technical specifications and worked with the NSSS vendor, architect engineering firm and the NRC to obtain final approval to support license issuance. Andy worked for Public Service Electric & Gas at the Salem and Hope Creek Generating stations from 1984 to 1988 in the Operations, Start-up & Test and Licensing departments supporting restart of Salem following the ATWS event and initial startup of the Hope Creek 1 reactor. Andy worked for the Institute of Nuclear Power Operations (INPO) from 1988 to 2000 conducting plant inspections, technical assistance visits and event follow-up reviews at 42 U.S. reactor sites and 12 international sites. During this period, Andy served as the Refueling Coordinator at the Peach Bottom Atomic Power Station and team leader for the international Nuclear Plant Reliability Data System (NPRDS) project with WANO as a loaned employee while at INPO. Andy worked for Pennsylvania Power & Light Corporation at the Susquehanna Steam Electric Station from 2000 to 2002 as a Unit Supervisor in the Operations Department.

Andy's career with the NRC began in 2003 with his assignment to the Catawba Nuclear Station as the Resident Inspector following a five-month period in Region II as a Project Engineer for Branch I. He was promoted to the Catawba Senior Resident Inspector in 2006 and was transferred to the Oconee Nuclear Station as Senior Resident Inspector in September 2009. In addition to baseline inspection program activities associated with Catawba, Andy has participated in or led PI&R inspections, 95-001 and 95-003 inspections, Augmented and Special Inspections, a Component Design Basis Inspection and a B.5.b inspection. Andy has received ten awards in his 6 years with the NRC including a Regional Administrator's Employee Excellence Award.

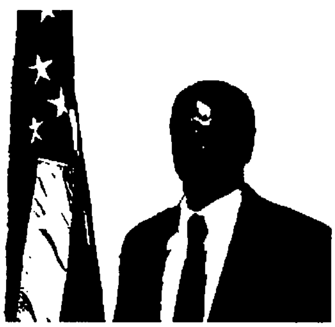
Mr. Sabisch received honorable discharges from the U.S. Navy and the Pennsylvania Army National Guard.

Kevin M. Ellis
Resident Inspector

Kevin joined the NRC in 2007. He is a (b)(6) York. He has been a resident inspector at the Oconee Nuclear Station since July 2009. Kevin began his career in 2002 as a nuclear engineer for Norfolk Naval Shipyard where he qualified as a shift refueling engineer. Kevin was initially hired as a project engineer in Region II, Division of Reactor Projects. He acted as the resident inspector at the V. C. Summer Nuclear Plant and then worked as the project engineer for Branch 4, Division of Reactor Projects.

He graduated Cum Laude from Florida Institute of Technology with a Bachelor of Science degree in Mechanical Engineering in (b)(6)

Geoffrey K. Ottenberg
Resident Inspector



Geoff joined the NRC in 2004. He is a native of Homestead, Florida. He has been a resident inspector at the Oconee Nuclear Station since September 2008. Previously, he worked as a researcher at Argonne National Laboratory on a fellowship assignment. In the NRC, Geoff was initially hired as a reactor engineer in Region I, Division of Reactor Projects. After qualifying as an inspector, Geoff worked in Region I, Division of Reactor Safety, as a reactor inspector doing primarily Component Design Basis Inspections, and also completed a 6-month rotation as resident inspector at the Susquehanna Steam Electric Station.

Geoff received his bachelor's degree in Mechanical Engineering from the Florida State University in (b)(6) and is a registered engineer intern in the State of Florida.

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

BRIEFING BOOK

FOR

COMMISSIONER KRISTINE L. SVINICKI

OCONEE NUCLEAR STATION

February 1, 2012

D 62

CONTENTS

Agenda for Commissioner Svinicki's visit to Oconee Nuclear Station

January 31, 2012
Depart DC for Greenville-Spartanburg (GSP) airport and drive to Clemson

February 1, 2012

7:20 a.m.	Leave the hotel for Oconee Nuclear Station
7:50 a.m.	Arrive at the World of Energy visitors center for overview discussion of the Keowee-Toxaway Project
8:20 a.m.	Depart the World of Energy for the Jocasse Hydro-Electric Facility
9:00 a.m.	Arrive at the Jocasse Hydro-Electric Facility for tour of powerhouse and dam structure (dam face drive-over, west saddle dyke, spillway, monitoring wells and powerhouse)
10:50 a.m.	Depart the Jocasse Hydro-Electric Facility for the Oconee Nuclear Station
11:30 a.m.	Arrive back at the Oconee Nuclear Station and the tour the current / planned external flood protection modifications along with the B.5.b Hale Pump location at the intake canal (NEO to be prepared to address questions and provide access to storage building)
12:15 p.m.	Process into the Protected Area (The Senior Resident Inspector will be the assigned escort for HQ personnel)
12:30 p.m.	Working lunch with the station management team (includes a Q&A portion with the attendees)
1:45 p.m.	Tour of the Protected Area to include: • Main Steam Isolation Valve project • The Natural Phenomena Barrier System • Standby Shutdown Facility (SSF) DG and control room • Alternate SSF power feed from Protected Service Water (PSW) – Raceway and cables entering the Auxiliary Building • The PSW building • Turbine Building basement (drain on South end, Unit 3 EFW pumps) and ground floor (train separation and bus duct issues) • The Unit 1 / Unit 2 Control Room / Cable Room (new digital RPS / ES equipment) • Outage Command Center
3:45 p.m.	Meeting between Commissioner Svinicki and the senior management team
4:15 p.m.	Tour the Keowee Hydro Facility (emergency power source for the Oconee Nuclear Station)
5:00 p.m.	Depart site for Greenville-Spartanburg airport and return to DC

PROTECTED AREA TOUR ROUTE

- Depart Resident Inspector Office
- Go to the 6th floor of the OOB for an overview of the site (ISFSI, Intake, power block, SSF, discharge)
- Discuss the pending MSIV modification using the north end of Unit 1 for visualization
- Enter the north end of the SSF building, go past the SSF DG's and up to the SSF control room. Discuss the function of the portable pump and cable reel.
- Discuss the Unit 2 BWST NPBS project and the work that was done (FiberWrap, siding, steel plating, etc.)
- Walk past the raceway and discuss the power cables being installed
- Walk through the PSW building and explain function and status of project
- Enter the Turbine Building on the south end and descend to the basement level and walk past the drain opening and the EFW pumps.
- Take the center stairs to the ground floor and show the bolted bus ducts and the Unit 3 4160V switchgear to show the vulnerability from a HELB along the west wall
- Return to the center stairs on the east side of the building and go up to the operating deck
- Tour the Unit 1 / 2 main control room to include a board walk down, TSC walkthrough and discussion of the new RPS/ES system as well as the cable room (EPSL cabinets, etc.)
- Tour the Outage Command Center
- Return to the Admin Building. Commissioner Svinicki to meet privately with the senior management team.
- Depart the Protected Area and arrive at Keowee Hydro Unit for tour
- Complete tour and leave site for airport

Executive Summary

Purpose of the visit/meeting
- Meet the Oconee Resident office staff
- Meet the Oconee senior management team
- Tour the Jocasse Hydro Facility
- Tour portions of the plant including ongoing tornado and HELB modifications
- Tour the Unit 1 / Unit 2 Main Control Room including the new digital RPS/ES equipment installed during the Spring 2011 refueling outage
- Tour the Keowee Hydro Facility

Issues to be addressed (See TAB 6)
- External flooding / GI-204
- NFPA 805 transition
- Tornado and HELB mitigation
- Digital Reactor Protective System / Engineered Safeguards Protective system project

Personnel to meet

Oconee Personnel (See TAB 8)
- Bill Pitesa, Senior Vice President of Nuclear Operations
- David Baxter, Vice President of Nuclear Engineering
- Preston Gillespie, Site Vice President
- Tom Ray, Engineering Manager
- Richard Freudenberger, Manager, Regulatory Affairs
- Bob Guy, Organizational Effectiveness Manager
- Terry Patterson, Safety Assurance Manager
- Dean Hubbard, External Flood Regulatory Support Manager

Region II Personnel (See TAB 9)
- Rick Croteau, Director, Division of Reactor Projects
- Andy Sabisch, Senior Resident Inspector
- Kevin Ellis, Resident Inspector
- Geoffrey Ottenberg, Resident Inspector
- Rebekah Wilbanks, Site Secretary

Activities on site
- Meet with Resident office staff
- Working lunch with Oconee staff including a question-&-answer session
- Meeting with the Duke management team to discuss plant, corporate and industry issues
- Plant tour with the resident inspectors and members of the licensee's staff
- Tour the Jocasse and Keowee hydro facilities

Messages to be communicated (Reference TAB 6)
- Continue to focus on safe plant operation
- Important to keep Tornado/HELB modifications on track
- Recognize the challenge of managing multiple major projects
- Seek opportunities to modify schedule based on risk reduction

Licensee's briefing topics

- The Duke Fleet is implementing actions to improve corporate governance and oversight
- Oconee Performance and Direction
- Major investments to enhance safety, improve reliability, resolve licensing basis issues, and reduce overall station risk profile are continuing

Licensee Ownership Information

Duke Energy Carolinas owns and operates the three-unit Oconee Nuclear Station located near Seneca, SC and the two-unit McGuire Nuclear Station located near Huntersville, NC. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station located in York, SC.

Duke Energy and Progress Energy have delayed the closing date of their $13.7 billion corporate merger, which they had hoped to wrap up in 2011, but in December, federal regulators rejected a proposal in which the companies offered to sell power for eight years under a "virtual divestiture" plan in the Carolinas. The merger could be completed in May or June pending regulatory approval from the Federal Energy Regulatory Commission (FERC).

Recent Oconee Management Changes (Reference TAB 7)

The following management changes have been implemented over the past six months:

- Rich Freudenberger was reassigned from the Safety Assurance Manager position to Manager, Regulatory Interface. In this role he is responsible for management of site programs and processes related to regulatory compliance.
- Dave Baxter is vice president of nuclear engineering for Duke Energy.
  In his role, he is responsible for corporate engineering support of Duke Energy's fleet of reactors including fuel management, reactor core design, and nuclear safety analysis; reload analysis methods, fleet program engineering, fleet procurement engineering, fleet component engineering, fleet electrical engineering and nuclear fuel procurement. Since November 2011, Dave has been on temporary assignment providing regulatory support for Oconee Nuclear Station.

ROP Assessment - Significant ROP Inspection Findings (Reference TAB 5)

A Special Inspection was initiated when the licensee identified that the breakers for pressurizer heaters powered from the SSF could trip prematurely. As a result of the inspection, three potentially greater than Green findings were identified for failing to maintain design control of SSF components and failing to perform adequate operability evaluations. A Final Significance Determination letter was issued on December 6, 2011, and resulted in one Yellow finding with an associated notice of violation and one Green non-cited violation.

Potential Discussion Topics (Reference TAB 6)

External Flood Action Plan

An issue related to the potential impact that external flooding would have on the Oconee Nuclear Station is currently being addressed by both the licensee and NRC. The licensee has developed Interim Compensatory Measures (ICMs) to address the external flooding concerns and is working on permanent actions to ensure the station is not adversely affected by a potential external flooding scenario. A Confirmatory Action Letter (CAL) was issued on June 22, 2010, to confirm that the ICMs would remain in place until final modifications have been completed. The CAL also requested the licensee to provide a list of modifications to enhance the capability of the Oconee Nuclear Station to withstand the postulated failure of the Jocassee Dam. By letter dated April 30, 2011, the licensee

responded to that CAL request. The NRC staff has reviewed the licensee's response, and by letter dated August 18, 2011, requested the licensee to provide clarifying information. The staff is reviewing the licensee's response.

NFPA 805 Transition

Oconee is one of two pilot plants that are in the process of transitioning to NFPA 805 for fire protection. The NRC staff completed its review of the License Amendment Requests (LAR) and issued the final licensee amendment on December 29, 2010. The licensee is currently performing modifications to be in compliance with NFPA 805.

Tornado & High Energy Line Break (HELB) Mitigation

The licensee is implementing a number of major modifications designed to minimize the risk exposure resulting from events such as tornado and a high-energy line break. The licensee submitted several LARs to update the Updated Final Safety Analysis Report (UFSAR). The staff has issued numerous Requests for Additional Information and the licensee is in the process of responding to the requests. The modifications to reinforce the outer masonry block walls of the Auxiliary Building and Cask Decontamination Tank rooms, as well as provide missile protection for the Borated water storage tanks have been completed. Remaining modifications are in progress and on schedule.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)

The licensee is currently implementing a major modification to all three units' Reactor Protection System and Engineered Safeguards Features Actuation System (RPS/ESFAS). The licensee has installed the new digital system on Unit 1 (performed during the Spring 2011 refueling outage) and is preparing to install the system on Unit 3 in the Spring 2012 outage followed by Unit 2 in the Spring of 2013.

William States Lee III Nuclear Station Combined Operating License (COL) Application

The licensee submitted a 10 CFR 52 application for a combined operating license to the NRC on December 12, 2007, which was docketed on February 25, 2008. This project is on the site of the old Cherokee Nuclear Station project that was cancelled in the 1980's.

Tritium

Elevated levels of tritium have been detected in a single ground water monitoring well within the Owner Controlled Area; however, mitigation actions that the licensee initiated in 2011 have shown a significant reduction in the levels of tritium present and the latest values were below the 20,000 pCi/l reporting threshold.

Facility Location Map and Directions

Directions to Oconee Nuclear Station from Clemson, SC

1. Head west on S Carolina 28 W/US-123 S/US-76 W/Tiger Blvd — ~ 6 mi
   Continue to follow S Carolina 28 W/US-123 S/US-76 W
2. Turn right onto S Carolina 130 N/Rochester Hwy — 7.8 mi
   Destination will be on the right approximately 0.5 miles past the traffic light at junction SC HWY 183
3. Turn right onto S Carolina 183/E Pickens Hwy — 0.7 mi
4. Turn left into Oconee Nuclear Station

The Resident Inspector office numbers are 864-882-6927 or 864-873-3001.

Facility Data

Utility: Duke Energy Carolinas, LLC
Location: 8 miles northeast of Seneca, SC
County: Oconee County, SC

	UNIT 1	UNIT 2	UNIT 3
Docket Nos.	50-269	50-270	50-287
License Nos.	DPR-38	DPR-47	DPR-55
Full Power License Date	02/06/1973	10/06/1973	07/19/1974
Commercial Operation Date	07/15/1973	09/09/1974	12/16/1974
OL Expiration Date	02/06/2033	10/06/2033	07/19/2034

PLANT CHARACTERISTICS	All Units
Reactor Type	PWR
Containment Type	Dry Ambient
Power Level	2568 MWt (900 MWe)
NSSS Vendor	B & W

TAB 4

Facility Unique Features

Emergency Supply to 4160 Volt-AC Safety-Related Buses

Power to the safety-related buses is provided from the two Keowee Hydro Station generating units. A single Keowee Hydro Unit (KHU) will supply all emergency power. This power is supplied to Oconee by two connections; an overhead transmission line and an underground line. Gas turbines at the Lee Steam Station can also be made available manually via a separate overhead line to provide power if neither KHU is available.

Standby Shutdown Facility (SSF)

The SSF provides an alternate and independent means to achieve and maintain a hot standby condition for all three units following postulated turbine building flood, fire, and sabotage events. It consists mainly of one diesel generator, an auxiliary service water pump, and supporting equipment (in a seismically qualified building) and three standby makeup pumps (one in each unit's reactor building). Powered by the SSF diesel generator, the standby makeup pumps deliver water at approximately 26 gpm from the associated spent fuel pool to the reactor coolant pump seals. In support of primary decay heat removal, the SSF auxiliary service water pump supplies water from the condenser circulating water (CCW) system to the once-through steam generators. The SSF is able to maintain all three units in Mode 3 (525 degrees) for 72 hours. The proposed Tornado/HELB mitigation strategies also take credit for the SSF.

Low Pressure Service Water (LPSW)

As originally designed, long-term decay heat removal has relied on the non-safety, non-seismically qualified CCW piping system and its pumps to provide water to the safety-related LPSW pumps located in the turbine building basement. During loss of offsite power events, the CCW pumps lose power; therefore, decay heat removal and cooling water for safety-related pumps rely on the use of a siphon effect (between the lake and the CCW system) to provide water to the safety-related LPSW system.

Emergency Feedwater (EFW)

The safety-related EFW pumps (two per unit) are located in the turbine building basement. Each unit's EFW system must rely on the limited source of water in its seismically qualified upper surge tank and on the water contained in the condenser hotwell. However, cross-connect valves are provided between all three units' EFW systems. Identified EFW single failure vulnerabilities have been addressed through plant modifications and licensing basis changes/clarifications.

Containment Isolation

Several piping systems penetrating containment were designed without isolation valves (Main Steam), or redundant, reliable (QA-1) isolation devices (Main Feedwater). In 2002, a new automatic feedwater isolation system (AFIS) modification was installed that secures/isolates both main and emergency feedwater to the affected steam generator. Supplemental diesel air compressors are used to compensate for the expected bleed off of valve operating air pressure should a coincident loss of offsite power occur.

TAB 5

Reactor Oversight Process Info

The following URLs are for the Oconee Nuclear Station (Units 1, 2 and 3) ROP Performance Summary web pages.

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO1/oco1_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO2/oco2_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO3/oco3_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/pi_summary.html

ROP Performance Status (1st Quarter 2011 – 4th Quarter 2011)

The licensee was in the Licensee Response Column of the NRC's Action Matrix based on all inspection findings being classified as having very low safety significance (Green) and all PIs indicating performance at a level requiring no additional NRC oversight (Green). However, a Yellow Mitigating Systems Cornerstone finding for Units 1, 2, and 3, originated in the third quarter of 2011. This finding is being evaluated to determine whether it meets the criteria for treatment as an old design issue per IMC 0305. A partial 95002 inspection is being conducted the week of February 6, 2012, in order to gather information to help the NRC determine how the finding should be treated. If the finding is determined not to meet the criteria for an old design issue, the licensee will be moved to the Degraded Cornerstone Column effective third quarter of 2011.

TAB 6

Current Issues

A. EXPECTED DISCUSSION TOPICS

External Flood

An issue related to the potential impact of external flooding on the Oconee Nuclear Station site has been raised as a result of the potential random failure of the Jocassee Dam, which is located approximately 12 miles upstream from the Oconee site. On August 15, 2008, the NRC issued a request for information pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 50.54(f), regarding the protection against external flooding at the Oconee site, including the potential failure of the Jocassee Dam.

In January 2010, the licensee began taking actions to ensure the Oconee site would be protected from external flooding as a result of the potential failure of the Jocassee Dam by implementing interim compensatory measures (ICMs). The NRC inspected the ICMs in June 2010 and no significant issues were identified.

On June 22, 2010, the NRC issued a confirmatory action letter (CAL) The CAL confirmed the following actions to be taken by the licensee concerning external flooding:

- ICM's to remain in place until final resolution of external flooding at the Oconee site has been agreed upon between the licensee and the NRC staff. **COMPLETE**

- Licensee to submit to the NRC all documentation necessary to demonstrate that the inundation of the Oconee site from the failure of the Jocassee Dam has been bounded – **COMPLETE**

- The licensee is to provide a list of all modifications necessary to mitigate the inundation and a schedule when they would be completed. **COMPLETE**

NRC Safety Evaluation of Site Inundation Study Results issued 01/28/2011. **COMPLETE**

The licensee provided modification descriptions and schedule on 04/30/2011. **COMPLETE**

NRC responded to licensees 04/30/2011, letter with RAIs 08/18/2011. **COMPLETE**

Licensee responded to RAIs 10/11/2011. **COMPLETE**

The NRC is currently reviewing the licensee's 10/11/2011 letter, and will be coordinating with the JLD task force to ensure there is regulatory consistency between the licensee's proposed modifications, and forthcoming requirements concerning external flooding.

The licensee's permanent solution is to erect flood barrier walls to mitigate the inundation of the site as a result to the potential failure of the Jocassee Dam. The licensee is finalizing the design inputs (velocity, height, etc) that will go into the actual modification and construction design of the walls.

Tornado & High Energy Line Break (HELB) Mitigation

The licensee is implementing a number of major modifications designed to minimize the risk exposure resulting from events such as tornado and a HELB , as well as adding equipment that was not part of Oconee's initial design basis; i.e., protected service water (PSW) system modification, main steam isolation valves, fiber reinforced polymer (FRP) on exterior walls, and hardening of structures.

The application of FRP on building exterior walls, and the hardening of structures at the Oconee help the site to withstand wind loads, differential pressure and missiles generated by a tornado.

The PSW system modification includes a new main pump and a booster pump to provide a diverse source of water to feed the steam generators in all 3 units and provide cooling to the reactor coolant pump seals in the event of a fire, tornado or HELB, if normal plant systems have been damaged. In addition, the PSW system modification includes installing new diverse power sources to existing plant high pressure emergency core cooling systems pumps. The licensee is scheduled to complete the modification by July 2012.

As part of the PSW modification and the design basis reconstitution for the tornado and HELB mitigation strategies, the licensee has submitted license amendments requesting review and approval of the PSW system modification, incorporating the system into the plant's Technical Specifications, and approving the new proposed mitigation strategies. The NRC staff is currently reviewing the amendments. The NRC staff has requested additional information from the licensee which is required for the NRC staff to completes its' review. The licensee is scheduled to have all the necessary information submitted to the NRC in March, 2012.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)

In January, 2010, the NRC issued a license amendment approving a first of a kind application of a digital computer based RPS/ESPS systems to replace the existing analog RPS/ESPS systems at Oconee. The licensee has installed the new digital system on Unit 1 (performed during the Spring 2011 refueling outage) and is preparing to install the system on Unit 3 in the Spring 2012 outage followed by Unit 2 in the Spring of 2013. The Region II Division of Reactor Safety is currently leading the NRC inspection effort supported by the resident inspectors.

NFPA 805 Transition

Oconee is one of two pilot plants that are in the process of transitioning to NFPA 805 for fire protection. The NRC staff completed its review of the License Amendment Requests (LAR) and issued the final licensee amendment on December 29, 2010. The licensee is currently performing modifications to be in compliance with NFPA 805. The licensee is scheduled to complete all modification associated with the transition by December, 2012.

William States Lee III Nuclear Station Combined Operating License (COL) Application

By letter dated December 12, 2007, Duke Energy Carolinas, LLC (Duke) tendered a COL application for two Westinghouse AP1000 advanced passive pressurized water reactors designated as Units 1 and 2 of the William States Lee III Nuclear Station. The proposed site is located in the eastern portion of Cherokee County in north central South Carolina, approximately 35 miles southwest of Charlotte, North Carolina, and approximately 7.5 miles southeast of Gaffney, South Carolina.

Tritium

Elevated levels of tritium have been detected in a ground water monitoring well within the Owner Controlled Area. In February 2010, one well exceeded the 20,000 pCi/l threshold which initiated the NEI Groundwater Communication plan. The local media outlets carried the story for several days and additional interest was indicated during the annual public meeting for 2009. The licensee has installed additional monitoring wells and is conducting sampling & analysis to determine if the source is an active leak or a legacy issue. The latest sample values indicate that the tritium levels in the well have decreased below the 20,000 pCi/l threshold.

B. OTHER TOPICS OF INTEREST

Labor/Management Issues

None

License Renewal Activities

The Oconee Site-Specific Independent Spent Fuel Storage Installation (ISFSI) license was renewed on May 29, 2009, for 40 additional years. This included a 20 year renewal plus an exemption which allows for an additional 20 years. The license will now expire on January 31, 2050.

Escalated Enforcement, Non-Green Findings and Non-Green Performance Indicators

A licensee-identified Yellow violation of 10 CFR 50 Appendix B, Criterion III, Design Control, was identified when the licensee installed Standby Shutdown Facility (SSF) pressurizer heater breakers that would not have functioned during certain SSF-credited events. The failure to maintain design control of the SSF was a performance deficiency.

Open Investigations

There is one open OI investigation.

Open Allegations

There is one open allegation related to access authorization.

Congressional Interest

None

Harassment and Intimidation Issues

None

2.206 Petitions

None

Recent News Articles

(b)(4)

(b)(4)

(b)(4)

(b)(4)

(b)(4)

(b)(4)

(b)(4)

(b)(4)

(b)(4)

TAB 7

Facility Organization

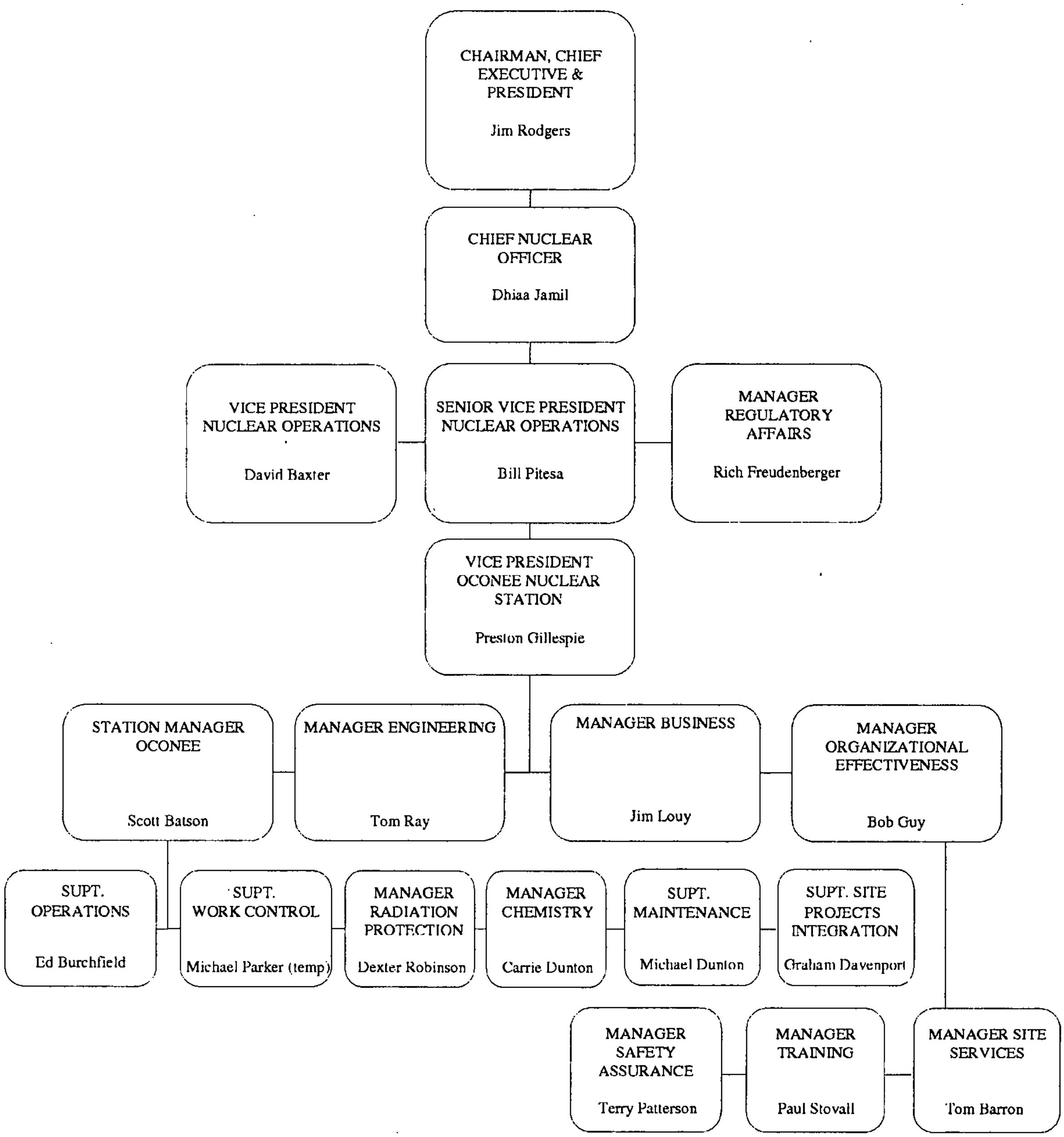
OVERVIEW OF DUKE ENERGY

Duke Energy Carolinas

Duke Energy Carolinas operations include nuclear, coal-fired, natural gas, and hydroelectric generation. This diverse fuel mix provides nearly 19,000 megawatts (MW) of electricity to approximately 2.4 million electric customers in North Carolina and South Carolina. Duke Energy Carolinas owns and operates the two-unit McGuire and the three-unit Oconee nuclear stations. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station.

Duke Energy submitted a 10 CFR 52 application for Lee Nuclear Station for a combined operating license to the NRC on December 13, 2007, which was docketed on February 25, 2008. A public scoping meeting was also held on May 1, 2008, near the proposed site location. The license application references the Westinghouse AP1000 as the reactor type and two reactors are planned for the site. The location is just south of the North Carolina/South Carolina border near Gaffney, S.C.

DUKE ENERGY
OCONEE NUCLEAR STATION
ORGANIZATIONAL CHART



Biographical Data of Principal Managers

John W. (Bill) Pitesa
Senior Vice President – Nuclear Operations

Bill Pitesa is senior vice president of nuclear operations for Duke Energy. He provides oversight for the safe and reliable operation of the three Duke Energy-operated nuclear stations – Catawba, McGuire and Oconee. Having served as senior vice president of nuclear operations for Oconee Nuclear Station since January 2010, Pitesa assumed the additional responsibility for Catawba and McGuire nuclear stations in December 2010. Pitesa has more than 30 years of experience in the nuclear field.

He joined the company in 1980 as an engineer at McGuire Nuclear Station. He was named senior reactor operator in 1986 and later served as a nuclear fuel handling supervisor and operations staff lead. In 1992, he served two years as a loaned employee for the Institute of Nuclear Power Operations.

Pitesa returned to McGuire Nuclear Station in 1995 as an independent oversight manager and later moved to the corporate office as the nuclear operating experience manager. In 2000, he moved to Catawba Nuclear Station as an engineering supervisor. After a series of promotions, including operations training manager, Pitesa was named as the station's operations manager in 2004 and station manager of Catawba Nuclear Station in 2005. In 2009, Pitesa was named vice president of nuclear support for Duke Energy. He was responsible for corporate nuclear engineering, major projects, licensing and regulatory support, fleet outage management and other plant support functions.

Pitesa earned a Bachelor of Science degree in electrical engineering from Auburn University. He is a registered professional engineer in North Carolina. In support of the International Atomic Energy Agency (IAEA) and the World Association of Nuclear Operators (WANO), Pitesa has served on nuclear plant review teams in the United States, Korea, France, South Africa, and Ukraine.

David A. Baxter
Vice President – Nuclear Engineering

Dave Baxter is vice president of nuclear engineering for Duke Energy. Since November 2011, Dave has been on temporary assignment providing regulatory support for Oconee Nuclear Station. Previously in his role as vice president of nuclear engineering, he was responsible for corporate engineering support of Duke Energy's fleet of reactors including fuel management, reactor core design, and nuclear safety analysis; reload analysis methods, fleet program engineering, fleet procurement engineering, fleet component engineering, fleet electrical engineering and nuclear fuel procurement. Duke Energy operates seven pressurized water reactors at Catawba, McGuire and Oconee nuclear stations in North Carolina and South Carolina. He was named to this position in October 2010.

Previously, Baxter served as site vice president of Oconee Nuclear Station in Seneca, S.C., a position he held since January 2008. In that role, he was responsible for the safe and reliable operation of Oconee Nuclear Station, a three-unit, pressurized water-reactor nuclear generating facility. He also directed station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations. Baxter has over 30 years of experience in nuclear engineering with Duke Energy. He joined the company in 1979 as a junior engineer at McGuire Nuclear Station in Huntersville, N.C. After a series of promotions at McGuire, including operations staff engineer, operations shift technical advisor, operations shift engineer and operations section manager, he was named nuclear engineering manager for modifications at Catawba Nuclear Station in 1998; and nuclear engineering manager for mechanical and civil engineering in 1999. He was named engineering division manager of Oconee Nuclear Station in 2002; and station manager in 2006. In that role, he was responsible for managing all aspects of Oconee's day-to-day operations.

Baxter earned a Bachelor of Science degree in nuclear engineering from Pennsylvania State University. Additionally, he has received a U.S. Nuclear Regulatory Commission Senior Reactor Operator License and the Institute of Nuclear Power Operations' Senior Nuclear Plant Management Certification.

T. Preston Gillespie Jr.
Site Vice President - Oconee Nuclear Station

Preston is responsible for the safe and reliable operation of Oconee Nuclear Station, a three-unit, pressurized water-reactor nuclear generating facility. He directs station and facilities management, operations, maintenance, chemistry and radiation protection, engineering, nuclear and industrial safety, and business operations. He joined Duke Power in 1986 as an assistant engineer at Oconee Nuclear Station. He served in a variety of positions while at the station, including nuclear operations shift manager, shift operations manager, and nuclear engineering manager. He moved to Catawba Nuclear Station in 2007 to serve as the station's operations superintendent. He was named Oconee Station Manager in October 2008 and moved to his current position in September 2010.

Preston graduated from Clemson University with a Bachelor of Science degree in mechanical engineering. He is a registered professional engineer in South Carolina. He held a senior reactor operator license at Oconee Nuclear Station. He is also a past recipient of the company's Robinson Award, which recognized employees for their outstanding contributions to the company's operations.

Robert (Bob) H. Guy
Organizational Effectiveness Manager

Bob is responsible for managing station support functions including training, site services, security, emergency preparedness, performance improvement, environmental and safety, and regulatory compliance. Bob joined Duke Energy in May 2011.
Prior to joining Duke Energy, Bob had over thirty years of experience in military, government and commercial nuclear fields. Guy trained in nuclear power after graduating from the Naval Academy. He served in a variety of positions on several submarines including supervision of the nuclear propulsion department. Other assignments included operations training instructor and training manager at the Nuclear Power Training Unit Idaho Falls, on the staff of the Director of Naval Reactors and overseas duty in Australia and Japan. He commanded the nuclear submarine USS Greeneville (SSN 772) from 1996 to 1999, commanded Naval Nuclear Power Training Unit Charleston from 2002 to 2006 and Naval Nuclear Power Training Command from 2006 to 2007. After retiring from the Navy, he served as a Nuclear Safety Specialist in the Office of Independent Oversight, U.S. Department of Energy and was later employed as Manager of Nuclear Oversight, Salem Nuclear Generating Station with PSEG Nuclear.

Bob earned a Bachelor of Science degree in Marine Engineering from the United States Naval Academy.

Thomas (Tom) D. Ray
Engineering Manager

Tom is responsible for managing and directing activities at the station related to system, component, and design engineering. He joined the company in 1989 as an associate engineer in the nuclear generation department in Charlotte. He was named senior engineer of reactor engineering at McGuire Nuclear Station in 1994; engineering supervisor in 1999; maintenance manager in 2002; and outage manager in 2003. He was named safety assurance manager at Catawba Nuclear Station in 2004, maintenance superintendent in 2005, and most recently engineering manager. Ray was named engineering manager of Oconee Nuclear Station in September 2010. Before joining the company, Ray was an engineer for Bechtel Power Corporation, from 1987 to 1989.

Ray earned a Bachelor of Science degree in nuclear engineering from North Carolina State University. He is a registered professional engineer in North Carolina and has a technical nuclear certification. He also serves as a Duke Energy management committee representative for the Pressurized Water Reactor Owners Group.

Terry L. Patterson
Safety Assurance Manager – Oconee Nuclear Station

Terry is responsible for the management of site programs and processes related to environmental health and safety, regulatory compliance, performance improvement, emergency planning and security. He filled this position in October 2010 coming from Constellation Energy Nuclear Group (CENG). Terry has over 30 years of commercial nuclear power experience. Prior to joining Duke Power, Terry spent five years in the nuclear submarine service where he served as the Main Propulsion Assistant on a nuclear ballistic missile submarine. He also spent three years with Combustion Engineering, Inc., fifteen years at Omaha Public Power District's (OPPD) Fort Calhoun Station and thirteen years at Florida Power and Light's (FPL) St. Lucie Nuclear Station.

Terry earned a Bachelor of Science degree in Physics from the U. S. Naval Academy, Annapolis, Maryland and a Masters in Business Administration from the University of Nebraska.

Richard (Rich) J. Freudenberger
Manager, Regulatory Affairs – Oconee Nuclear Station

Rich is responsible for the management of site programs and processes related to regulatory compliance and licensing. He was named to his current position in February 2010. Previously, Rich served as safety assurance manager of Oconee Nuclear Station since 2008. He was responsible for the management of site programs and processes related to environmental health and safety, regulatory compliance, performance improvement, emergency planning and security. Prior to joining Duke Power in 1997, Rich had 12 years of commercial nuclear power experience as a resident and senior resident inspector for the Nuclear Regulatory Commission at the Maine Yankee, Crystal River, and Catawba nuclear stations. His first position with Duke Power was as the regulatory audit supervisor. He was responsible for implementation of performance-based audits required by the Duke Energy Nuclear Quality Assurance program. In February 2000, Rich was assigned to the Oconee Nuclear Station as the secondary systems engineering supervisor and was responsible for the power conversion and standby shutdown systems mechanical design and licensing basis, testing support and equipment reliability. Between 2001 and 2007, he held several other supervisory positions within engineering. He successfully completed the operator training program and was licensed as a senior reactor operator in July 2004.

Rich earned a Bachelor of Science degree in marine engineering from the Maine Maritime Academy in Castine, Maine.

Dean Hubbard
Regulatory Affairs Manager – Oconee Nuclear Station

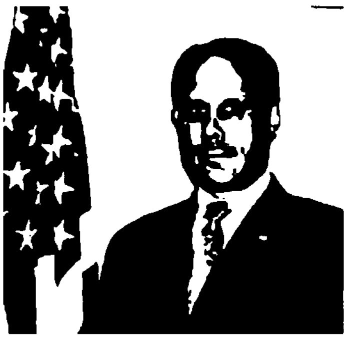
Dean Hubbard is the Regulatory Affairs Manager at Oconee Nuclear Station for Duke Energy. He is responsible licensing activities associated with the External Flood Mitigation Project. Hubbard joined the company in December 1980 as a Junior Engineer in Charlotte, NC. He has held numerous positions at the General Office and at Oconee including Engineer Performing system wide ASME Section 11 and PTC Acceptance Testing, Engineering Supervisor of the Systems Results Group, Performance Manager, (Instant) Senior Reactor Operator (SRO), Component Engineering Manager, Site Maintenance Manager, Site Modification Engineering Manager, Special Projects Manager for Steam Generator Replacement, and Site Training Manager. In December 2011, he was named the Regulatory Affairs Manager for the External Flood Mitigation Project. Hubbard has over 31 years of experience in engineering and plant operations with Duke Energy.

Hubbard earned a Bachelor of Science Degree in Civil Engineering from the University of North Carolina at Charlotte. Hubbard is a Registered Professional Engineer in South Carolina and North Carolina. He received a Senior Reactor Operator License from the U.S. Nuclear Regulatory Commission.

TAB 9

Resumes of Oconee Resident Inspectors

Andrew (Andy) T. Sabisch
Senior Resident Inspector



Andy joined the NRC in 2003. He is a (b)(6) (b)(6) Mr. Sabisch attended SUNY Maritime College and received his Bachelor degree in Nuclear Science with a minor in Computer Science.

Andy joined MetEd at the Three Mile Island Generating Station in Middletown, PA and worked in both the Operations department and the Unit 1 Recovery Group. He served as Shift Test Director in 1982 during hot functional testing conducted to support the restart of Unit 1 following the 1979 Unit 2 accident. Andy worked for Louisiana Power & Light from 1982 to 1984 as a Plant Engineering section manager supporting the construction and turnover of plant systems during startup of the Waterford 3 Steam Electric Station. In this role, he also was responsible for the development of the plant technical specifications and worked with the NSSS vendor, architect engineering firm and the NRC to obtain final approval to support license issuance. Andy worked for Public Service Electric & Gas at the Salem and Hope Creek Generating stations from 1984 to 1988 in the Operations, Start-up & Test and Licensing departments supporting restart of Salem following the ATWS event and initial startup of the Hope Creek 1 reactor. Andy worked for the Institute of Nuclear Power Operations (INPO) from 1988 to 2000 conducting plant inspections, technical assistance visits and event follow-up reviews at 42 U.S. reactor sites and 12 international sites. During this period, Andy served as the Refueling Coordinator at the Peach Bottom Atomic Power Station and team leader for the international Nuclear Plant Reliability Data System (NPRDS) project with WANO as a loaned employee while at INPO. Andy worked for Pennsylvania Power & Light Corporation at the Susquehanna Steam Electric Station from 2000 to 2002 as a Unit Supervisor in the Operations Department.

Andy's career with the NRC began in 2003 with his assignment to the Catawba Nuclear Station as the Resident Inspector following a five-month period in Region II as a Project Engineer for Branch I. He was promoted to the Catawba Senior Resident Inspector in 2006 and was transferred to the Oconee Nuclear Station as Senior Resident Inspector in September 2009. In addition to baseline inspection program activities associated with Catawba, Andy has participated in or led PI&R inspections, 95-001 and 95-003 inspections, Augmented and Special Inspections, a Component Design Basis Inspection and a B.5.b inspection. Andy has received numerous awards in his tenure with the NRC including a Regional Administrator's Employee Excellence Award.

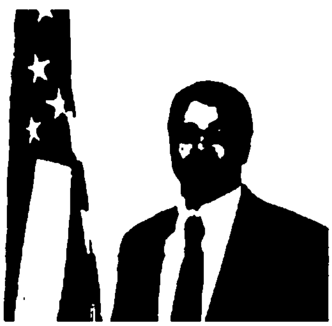
Mr. Sabisch received honorable discharges from the U.S. Navy and the Pennsylvania Army National Guard.

Kevin M. Ellis
Resident Inspector

Kevin joined the NRC in 2007. He is a (b)(6) (b)(6) He has been a resident inspector at the Oconee Nuclear Station since July 2009. Kevin began his career in 2002 as a nuclear engineer for Norfolk Naval Shipyard where he qualified as a shift refueling engineer. Kevin was initially hired as a project engineer in Region II, Division of Reactor Projects. He acted as the resident inspector at the V. C. Summer Nuclear Plant and then worked as the project engineer for Branch 4, Division of Reactor Projects.

He graduated Cum Laude from Florida Institute of Technology with a Bachelor of Science degree in Mechanical Engineering in (b)(6)

Geoffrey K. Ottenberg
Resident Inspector



Geoff joined the NRC in 2004. He is a (b)(6) (b)(6) He has been a resident inspector at the Oconee Nuclear Station since September 2008. Previously, he worked as a researcher at Argonne National Laboratory on a fellowship assignment. In the NRC, Geoff was initially hired as a reactor engineer in Region I, Division of Reactor Projects. After qualifying as an inspector, Geoff worked in Region I, Division of Reactor Safety, as a reactor inspector doing primarily Component Design Basis Inspections, and also completed a 6-month rotation as resident inspector at the Susquehanna Steam Electric Station.

Geoff received his bachelor's degree in Mechanical Engineering from the Florida State University in (b)(6) and is a registered engineer intern in the State of Florida.

Rebekah A. Wilbanks
Site Administrative Assistant

Rebekah joined the NRC in 2011. She is a (b)(6) (b)(6) She has been the site secretary for Oconee Nuclear Station since June 2011. Previously, she was enlisted in the United States Navy as a Yeoman for eight years before receiving an honorable discharge with multiple awards for superior performance and dedication. She was hired on as the site secretary for Oconee but currently works two sites in Branch 1: Oconee and McGuire.

Rebekah received an associate's of arts degree from American Military University in (b)(6)

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

BRIEFING BOOK

FOR

WILLIAM BORCHARDT, EXECUTIVE DIRECTOR FOR OPERATIONS

FOR A DROP-IN VISIT WITH DUKE ENERGY

FEBRUARY 16, 2012

CONTENTS

TAB 1A

Drop-In Visit Agenda

February 16, 2012

ITINERARY

TIME	PERSON VISITED	CONTACT PERSON	EXTENSION
4:00 PM	EDO	John Stang, PM	301-415-1345

REPRESENTING DUKE ENERGY

- Dhiaa M. Jamil, Group Executive, Chief Generation Officer and Chief Nuclear Officer
- John W. (Bill) Pitesa, Senior Vice President – Nuclear Operations
- M. Christopher Nolan, Fleet Safety Assurance Manager

TOPICS OF DISCUSSION

- Fleet Oversight
- Update on Merger Activities
- Fleet Performance
- Listen to Feedback from NRC

TAB 3

Facility Data

OCONEE NUCLEAR STATION

Utility: Duke Energy Carolinas, LLC
Location: 8 miles northeast of Seneca, South Carolina
County: Oconee County, South Carolina

	UNIT 1	UNIT 2	UNIT 3
Docket Nos.	50-269	50-270	50-287
License Nos.	DPR-38	DPR-47	DPR-55
Full Power License Date	02/06/1973	10/06/1973	07/19/1974
Commercial Operation Date	07/15/1973	09/09/1974	12/16/1974
OL Expiration Date	02/06/2033	10/06/2033	07/19/2034

Plant Characteristics	All Units
Reactor Type	PWR
Containment Type	Dry Ambient
Power Level	2568 MWt (900 MWe)
NSSS Vendor	B & W

MCGUIRE NUCLEAR STATION

Utility: Duke Energy Carolinas, LLC
Location: Huntersville, NC (17 miles north of Charlotte, North Carolina)
County: Mecklenburg County, South Carolina

	UNIT 1	UNIT 2
Docket Nos.	50-369	50-370
License Nos.	NPF-9	NPF-17
Full Power License Date	07/08/1981	05/27/1983
Commercial Operation Date	12/01/1981	03/01/1984
OL Expiration Date	06/12/2041	03/03/2043

Plant Characteristics	All Units
Reactor Type	PWR
Containment Type	Ice Condenser
Power Level	3411 MWt (1100 MWe)
NSSS Vendor	Westinghouse

TAB 3

Facility Data

CATAWBA NUCLEAR STATION

Utility: Duke Energy Carolinas, LLC
Location: York, SC (18 miles south of Charlotte, North Carolina)
County: York County, South Carolina

	UNIT 1	UNIT 2
Docket Nos.	50-413	50-414
License Nos.	NPF-35	NPF-52
Operating License Date	01/17/1985	05/15/1986
Commercial Operation Date	06/29/1985	08/19/1986
OL Expiration Date	12/05/2043	12/05/2043

Plant Characteristics	All Units
Reactor Type	PWR
Containment Type	Ice Condenser
Power Level	3411 MWt (1129 MWe)
NSSS Vendor	Westinghouse

TAB 5

Reactor Oversight Process (ROP) Information

The following URLs are for the Oconee Nuclear Station Units 1, 2 and 3, McGuire Nuclear Station Units 1 and 2, and Catawba Nuclear Station Units 1 and 2 ROP Performance Summary web pages.

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO1/oco1_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO2/oco2_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/OCO3/oco3_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/pi_summary.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/MCG1/mcg1_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/MCG2/mcg2_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/CAT1/cat1_chart.html

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/CAT2/cat2_chart.html

ROP Performance Status (1st Quarter 2011 – 4th Quarter 2011)

OCONEE

The licensee was in the Licensee Response Column of the NRC's Action Matrix based on all inspection findings being classified as having very low safety significance (Green) and all PIs indicating performance at a level requiring no additional NRC oversight (Green). However, a Yellow Mitigating Systems Cornerstone finding for Units 1, 2, and 3, originated in the third quarter of 2011. This finding is being evaluated to determine whether it meets the criteria for treatment as an old design issue per IMC 0305. A partial 95002 inspection is being conducted the week of February 6, 2012, in order to gather information to help the NRC determine how the finding should be treated. If the finding is determined not to meet the criteria for an old design issue, the licensee will be moved to the Degraded Cornerstone Column effective third quarter of 2011.

MCGUIRE

Licensee Response Column

CATAWBA

Licensee Response Column

TAB 6

Current Issues

A. EXPECTED DISCUSSION TOPICS

DUKE FLEET

Progress Energy/Duke Energy Merger

On January 10, 2011, Duke Energy and Progress Energy announced a merger that would base the combined North Carolina power companies in Charlotte and make it the nation's biggest electric utility with 7.1 million customers. The combined company would serve territories stretching from Ohio and Indiana to Florida.

On December 2, 2011, the NRC approved the indirect transfer of the control of the above facilities, including their associated independent spent fuel storage installations.

A mid-December decision issued by the Federal Energy Regulatory Commission (FERC) on the merger mitigation plan for the Carolinas has delayed the close of the merger. Duke Energy and Progress Energy are currently examining potential ways to address FERC's concerns and enable them to move forward with the merger. Both companies are working on the revised mitigation plans to address the FERC's concerns. The revised mitigation plans must be filed with the N.C. Utilities Commission (NCUC) prior to submittal to the FERC. Based on the time needed to complete the analysis and the estimated time for regulatory reviews and approvals, Progress Energy and Duke Energy estimate that the earliest the merger could close is May or June 2012. However, they will set a more specific timeline after the mitigation plans are filed with NCUC.

NFPA 805 Transition

Oconee is one of two pilot plants that are in the process of transitioning to NFPA 805 for fire protection. The NRC staff completed its review of the License Amendment Requests (LAR) and issued the final licensee amendment on December 29, 2010. The licensee is currently performing modifications to be in compliance with NFPA 805. The licensee is scheduled to complete all modifications associated with the transition by December, 2012.

The current plans are for Catawba and McGuire to submit license amendment request to transition to NFPA-805 by September 30, 2013.

William States Lee III Nuclear Station Combined Operating License (COL) Application

By letter dated December 12, 2007, Duke Energy Carolinas, LLC (Duke) tendered a COL application for two Westinghouse AP1000 advanced passive pressurized water reactors designated as Units 1 and 2 of the William States Lee III Nuclear Station. The proposed site is located in the eastern portion of Cherokee County in north central South Carolina, approximately 35 miles southwest of Charlotte, North Carolina, and approximately 7.5 miles southeast of Gaffney, South Carolina.

TAB 6

OCONEE

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In January 2010, the licensee began taking actions to ensure the Oconee site would be protected from external flooding as a result of the potential failure of the Jocassee Dam by implementing interim compensatory measures (ICMs). The NRC inspected the ICMs in June 2010 and no significant issues were identified.

On June 22, 2010, the NRC issued a confirmatory action letter (CAL). The CAL confirmed the following actions to be taken by the licensee concerning external flooding:

- ICM's to remain in place until final resolution of external flooding at the Oconee site has been agreed upon between the licensee and the NRC staff. **COMPLETE**

- Licensee to submit to the NRC all documentation necessary to demonstrate that the inundation of the Oconee site from the failure of the Jocassee Dam has been bounded – **COMPLETE**

- The licensee is to provide a list of all modifications necessary to mitigate the inundation and a schedule when they would be completed. **COMPLETE**

- NRC Safety Evaluation of Site Inundation Study Results issued 01/28/2011. **COMPLETE**

- The licensee provided modification descriptions and schedule on 04/29/2011. **COMPLETE**

- The licensee's permanent solution is to erect flood barrier walls to mitigate the inundation of the site as a result to the potential failure of the Jocassee Dam. The licensee is finalizing the design inputs (velocity, height, etc) that will go into the actual modification and construction design of the walls.

- NRC responded to licensees 04/29/2011, letter with RAIs 08/18/2011. **COMPLETE**

- Licensee responded to RAIs 10/17/2011. **COMPLETE**

The NRC is currently reviewing the licensee's letter dated October 17, 2011, and will be coordinating with FERC and the Japan Lessons-Learned Project Directorate task force to ensure there is regulatory consistency between the licensee's proposed modifications, and forthcoming requirements concerning external flooding.

TAB 6

Tornado & High Energy Line Break (HELB) Mitigation

The licensee is implementing a number of major modifications designed to minimize the risk exposure resulting from events such as tornado and a HELB, as well as adding equipment that was not part of Oconee's initial design basis; i.e., the protected service water (PSW) system modification, main steam isolation valves, fiber reinforced polymer (FRP) on exterior walls, and hardening of structures.

The application of FRP on building exterior walls, and the hardening of structures at the Oconee site helps the site to withstand wind loads, differential pressure and missiles generated by a tornado.

The PSW system modification includes a new main pump and a booster pump to provide a diverse source of water to feed the steam generators in all 3 units and provide cooling to the reactor coolant pump seals in the event of a fire, tornado or HELB, if normal plant systems have been damaged. In addition, the PSW system modification includes installing new diverse power sources to existing plant high pressure emergency core cooling systems pumps. The licensee is scheduled to complete the modification by November 2012.

As part of the PSW modification and the design basis reconstitution for the tornado and HELB mitigation strategies, the licensee has submitted license amendments requesting review and approval of the PSW system modification, incorporating the system into the plant's Technical Specifications, and approving the new proposed mitigation strategies. The NRC staff is currently reviewing the amendments. The NRC staff has requested additional information from the licensee which is required for the NRC staff to completes its' review. The licensee is scheduled to have all the necessary information submitted to the NRC in March 2012.

Digital Computer Based Reactor Protective System (RPS)/Engineered Safeguards Protective System (ESPS)

In January 2010, the NRC issued a license amendment approving a first of a kind application of a digital computer based RPS/ESPS systems to replace the existing analog RPS/ESPS systems at Oconee. The licensee has installed the new digital system on Unit 1 (performed during the Spring 2011 refueling outage) and is preparing to install the system on Unit 3 in the Spring 2012 outage followed by Unit 2 in the Spring of 2013. The Region II Division of Reactor Safety is currently leading the NRC inspection effort supported by the resident inspectors.

<u>MCGUIRE</u>

No discussion topics.

TAB 6

CATAWBA

Implementation of Permanent Alternative Repair Criteria for Steam Generator Tubes – H* - at Catawba 2

The NRC anticipates issuance of a license amendment by the end of February 2012 which will allow implementation of H* at Catawba 2 during their Spring 2012 outage. This will be the first such H* amendment in the US PWR fleet and will eliminate the need for future interim alternative repair criteria amendments.

B. OTHER TOPICS OF INTEREST

Labor/Management Issues

None

Escalated Enforcement, Non-Green Findings and Non-Green Performance Indicators

A licensee-identified Yellow violation of 10 CFR 50 Appendix B, Criterion III, Design Control, was identified when the licensee installed Standby Shutdown Facility (SSF) pressurizer heater breakers that would not have functioned during certain SSF-credited events. The failure to maintain design control of the SSF was a performance deficiency.

Open Investigations

There is one open OI investigation.

Open Allegations

There is one open allegation related to access authorization.

Congressional Interest

None

Harassment and Intimidation Issues

None

2.206 Petitions

None

TAB 6

Recent News Articles

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TAB 7

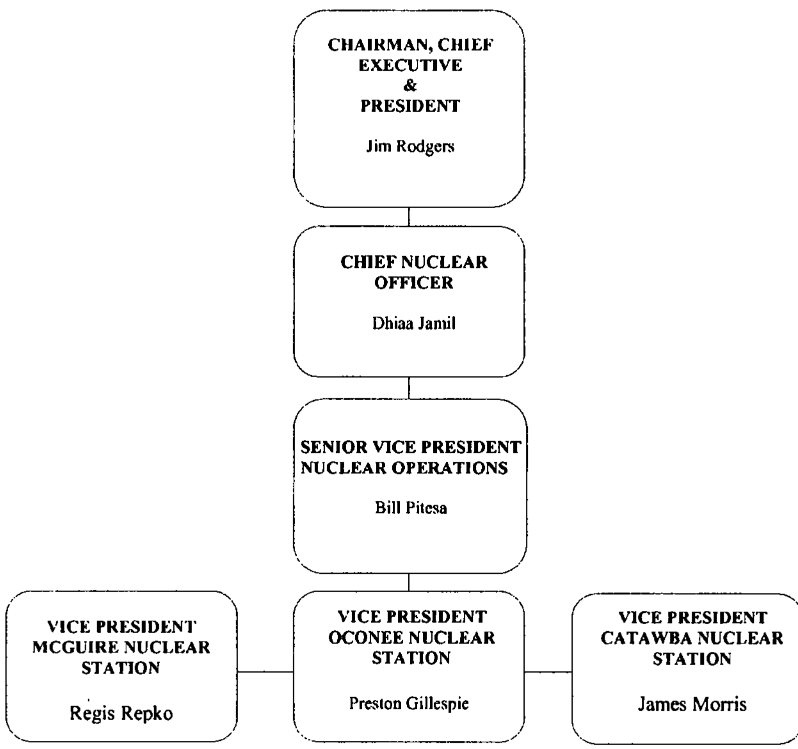
Facility Organization

OVERVIEW OF DUKE ENERGY

Duke Energy Carolinas

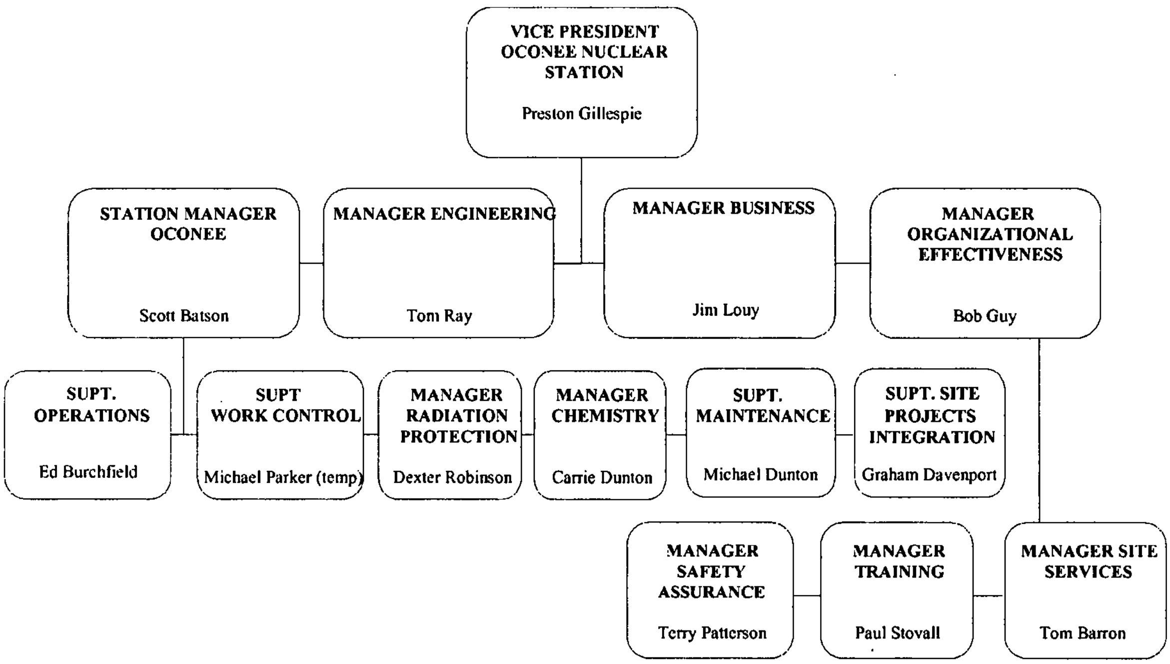
Duke Energy Carolinas operations include nuclear, coal-fired, natural gas, and hydroelectric generation. This diverse fuel mix provides nearly 19,000 megawatts (MW) of electricity to approximately 2.4 million electric customers in North Carolina and South Carolina. Duke Energy Carolinas owns and operates the two-unit McGuire and the three-unit Oconee nuclear stations. In addition, Duke Energy Carolinas operates and has a partial ownership interest in the two-unit Catawba Nuclear Station.

DUKE ENERGY ORGANIZATIONAL CHART



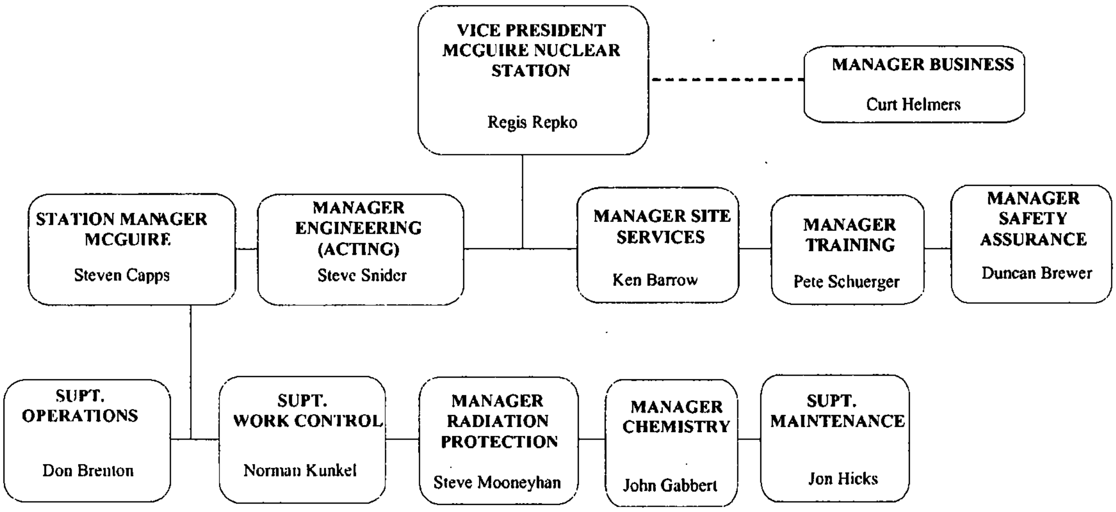
TAB 7

OCONEE NUCLEAR STATION ORGANIZATIONAL CHART



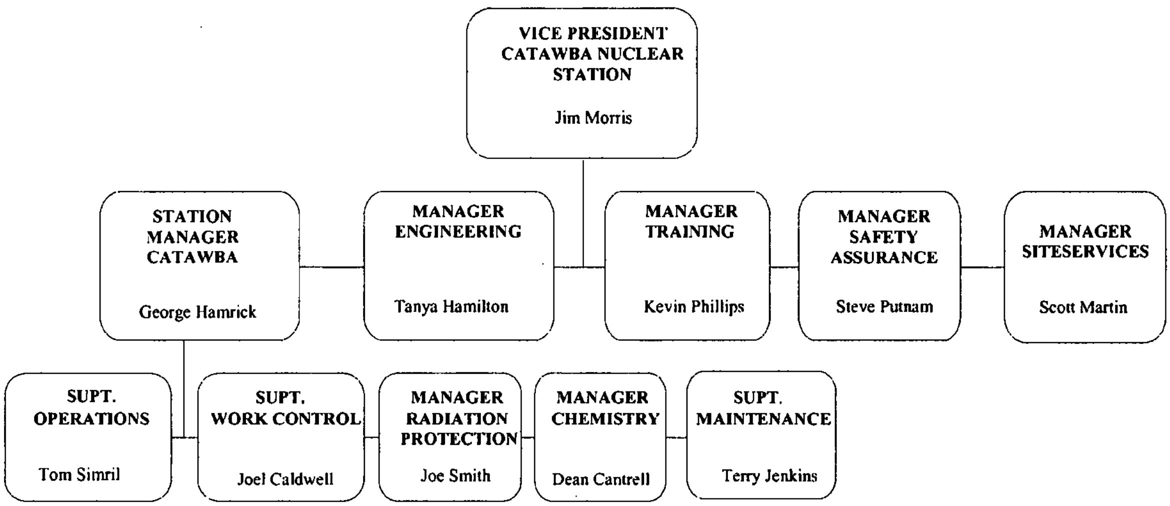
TAB 7

MCGUIRE NUCLEAR STATION
ORGANIZATIONAL CHART



TAB 7

CATAWBA NUCLEAR STATION
ORGANIZATIONAL CHART



TAB 8

Biographical Data of Principal Managers

Dhiaa M. Jamil
Group Executive, Chief Generation Officer and Chief Nuclear Officer

Dhiaa Jamil is a group chief generation officer and chief nuclear officer for Duke Energy. He is responsible for the safe and efficient operation of all regulated generation across the company's nuclear, fossil and hydro fleets. He assumed the expanded role of chief generation officer in July 2009. Previously, Jamil served as group executive and chief nuclear officer, with responsibility for the company's three nuclear stations Catawba, McGuire and Oconee. Jamil has more than 30 years of experience in the energy industry.

He joined Duke Power in 1981 as a design engineer in the design engineering department. After a series of promotions, he was named electrical systems engineering supervisor of Oconee Nuclear Station in 1989 and electrical systems engineering manager in 1994. He was named maintenance superintendent of McGuire Nuclear Station in 1997; station manager in 1999; and site vice president of McGuire Nuclear Station in 2002. In that role, Jamil was responsible for all aspects of the safe and efficient operation of the nuclear site. In 2003, he was named site vice president of Catawba Nuclear Station. In 2006, Jamil was named senior vice president of nuclear support. He led the organization responsible for plant support, major projects and fuel management for Duke Energy's nuclear fleet. In addition, he was responsible for regulatory support, nuclear oversight and safety analysis functions. Jamil received a Bachelor of Science degree in electrical engineering from the University of North Carolina at Charlotte.

He is a registered professional engineer in North Carolina and South Carolina. He has completed the Institute of Nuclear Power Operations' (INPO) senior nuclear plant management course and received Duke Energy's technical nuclear certification. He has served as a senior member of the Institute of Electrical & Electronics Engineers (IEEE) and has completed a three-year assignment as a member of the Council of the National Academy for Nuclear Training. He is a former member of Dominion Energy Management Safety Review Advisory Committee, TVA Nuclear Safety Review Board and Pacific Gas & Electric Nuclear Safety Oversight Committee. He also served on the board of directors of the York County, South Carolina, Chamber of Commerce.

Jamil currently serves as chair of the Energy Production and Infrastructure Center at the University of North Carolina (UNC) at Charlotte and is a member of the UNC Charlotte Board of Trustees. He is a member of the INPO Executive Advisory Group and the Nuclear Energy Institute's Nuclear Strategic Issues Advisory Committee Steering Group. He also serves as a trustee of The Duke Energy Foundation.

TAB 8

John W. (Bill) Pitesa
Senior Vice President – Nuclear Operations

Bill Pitesa is senior vice president of nuclear operations for Duke Energy. He provides oversight for the safe and reliable operation of the three Duke Energy-operated nuclear stations – Catawba, McGuire, and Oconee. Having served as senior vice president of nuclear operations for Oconee Nuclear Station since January 2010, Pitesa assumed the additional responsibility for Catawba and McGuire nuclear stations in December 2010. Pitesa has more than 30 years of experience in the nuclear field.

He joined the company in 1980 as an engineer at McGuire Nuclear Station. He was named senior reactor operator in 1986 and later served as a nuclear fuel handling supervisor and operations staff lead. In 1992, he served two years as a loaned employee for the Institute of Nuclear Power Operations.

Pitesa returned to McGuire Nuclear Station in 1995 as an independent oversight manager and later moved to the corporate office as the nuclear operating experience manager. In 2000, he moved to Catawba Nuclear Station as an engineering supervisor. After a series of promotions, including operations training manager, Pitesa was named as the station's operations manager in 2004 and station manager of Catawba Nuclear Station in 2005. In 2009, Pitesa was named vice president of nuclear support for Duke Energy. He was responsible for corporate nuclear engineering, major projects, licensing and regulatory support, fleet outage management and other plant support functions.

Pitesa earned a Bachelor of Science degree in electrical engineering from Auburn University. He is a registered professional engineer in North Carolina. In support of the International Atomic Energy Agency (IAEA) and the World Association of Nuclear Operators (WANO), Pitesa has served on nuclear plant review teams in the United States, Korea, France, South Africa, and Ukraine.

TAB 8

M. Christopher Nolan
Fleet Safety Assurance Manager

Chris Nolan is the manager of the nuclear fleet safety assurance organization for Duke Energy. He is responsible for leading the company's efforts to provide programmatic oversight for the fleet in the areas of security, emergency preparedness, performance improvement, licensing, and regulatory compliance. Most recently, Nolan served as the licensing manager in nuclear plant development for Duke Energy. He was responsible for managing licensing, site characterization and development activities for new nuclear interests in Duke's Midwest service territory.

Prior to this position, he managed the licensing effort for Lee Nuclear Station, located in Cherokee County, South Carolina. Nolan joined Duke Energy in 2006 after serving the U. S. Nuclear Regulatory Commission (NRC) for nine years. During this period, Nolan held positions of increasing responsibility in the Office of Nuclear Reactor Regulation, Office of Nuclear Security and Incident Response, and the Office of Enforcement. Nolan was the Chief of the New Reactors Environmental Projects Branch in the Office of Nuclear Reactor Regulation when he accepted a position with Duke Energy. Prior to his service with the NRC, Nolan was a senior design engineer at Calvert Cliffs Nuclear Power Plant where he worked for nine years.

Additionally, Nolan was a qualified operator in the U. S. Navy's nuclear power program while employed at the Knolls Atomic Power Laboratory for General Electric Co. A (b)(6) (b)(6) Nolan graduated from the University of Maryland where he earned a bachelor's of science degree in mechanical engineering. In addition, he is a graduate of the U. S. Navy's Nuclear Power School, he holds a master's degree in engineering management from the University of Maryland, and he is a registered professional engineer in the State of Maryland.

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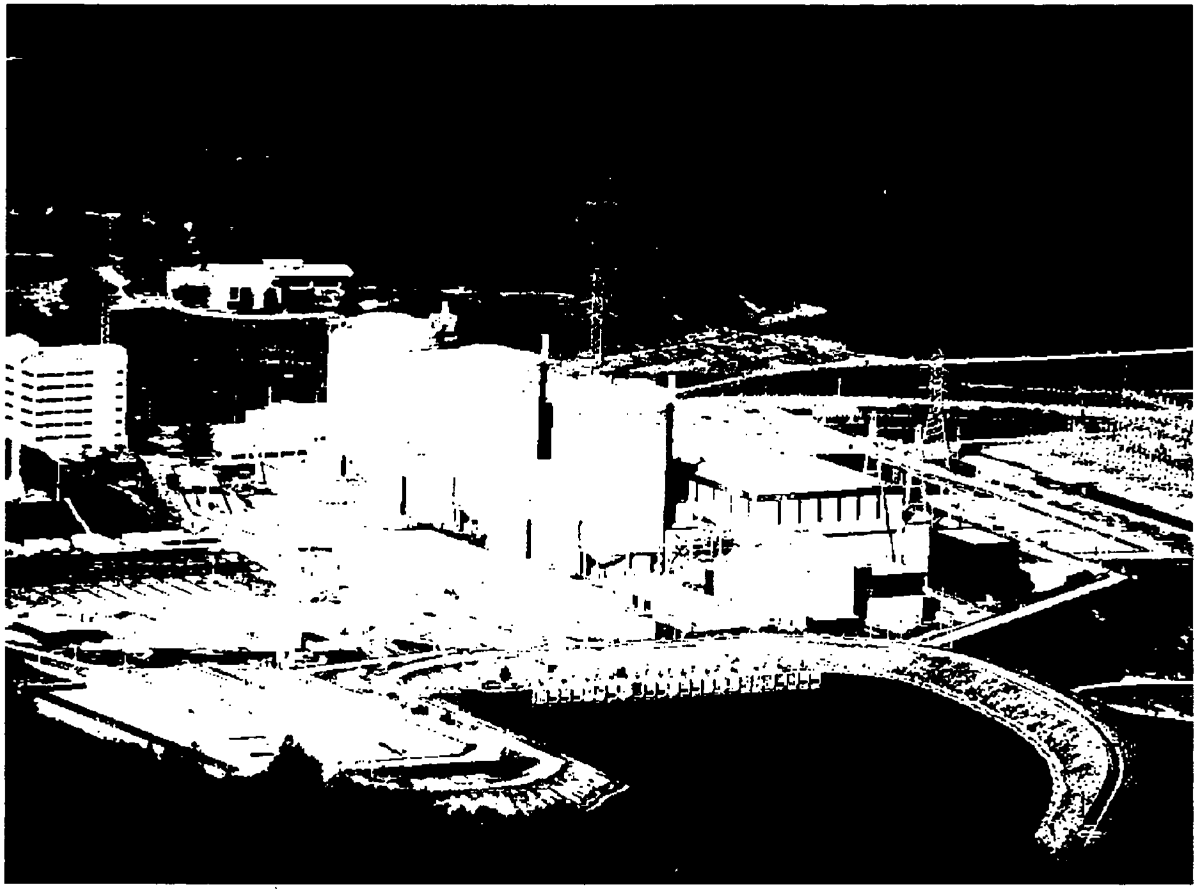
Duke Energy



Oconee Nuclear Station

External Flood Mitigation

NRC Headquarters

One White Flint North

Rockville, MD

July 11, 2012

~~Withhold from Public Disclosure under 10 CFR 2.390~~
For Information Only

Duke Attendees

Bill Pitesa, Sr. VP, Nuclear Operations

Regis Repko, Sr. VP, Nuclear Operations

Preston Gillespie, Site VP, Oconee Nuclear Station

Dave Baxter, VP, Nuclear Engineering

Chris Nolan, Director, Regulatory Affairs

Dean Hubbard, Licensing Manager, Oconee External Flood

Scott Lynch, General Manager, Oconee Major Projects

External Flooding Update

Dean Hubbard

Licensing Manager, Oconee External Flood

Regulatory Timeline

- June 2010 CAL to address external flooding
- July 2010 NRC inspection letter confirming interim actions
- Jan 2011 NRC SER on parameters and bounding analysis
- April 2011 Duke provided list of proposed modifications to mitigate flooding
- Aug 2011 NRC RAI's – design basis, QA condition, schedule for modifications (Oct 2011 Duke response)
- Mar 2012 Fukushima Order and 50.54(f) requests
- May 2012 NRC RAI's - wall codes & standards, seismic criteria (June 2012 Duke response)

Duke Energy

Risk Reduction

- All CAL Interim Commitments - implemented, inspected, and remain in place until mods completed
- Additional work completed to increase margin
  - Swale wall constructed near World of Energy
  - Temporary 10' intake wall to protect the yard
- Fukushima FLEX equipment purchased to be deployed in 2012 to meet N+1 response
- Jocassee specific PRA draft update shows an overall estimated failure probability of ~1.3 E – 06, which is much lower than the NRC generic dam failure probability of ~1.8 E-04

Modification Update

List of modifications in Duke Energy's April 29, 2011 letter:

- Dedicated Flood Protected Power – 100kV-line tower relocation, CT5 substation upgrade
- Spent Fuel Pool Makeup – Divert SSF service water discharge for SFP use, SFP level instrumentation
- Protect Required Systems, Structures, and Components – Power block flood wall, intake diversion wall, turbine building drain isolation, yard drain isolation

Duke Energy

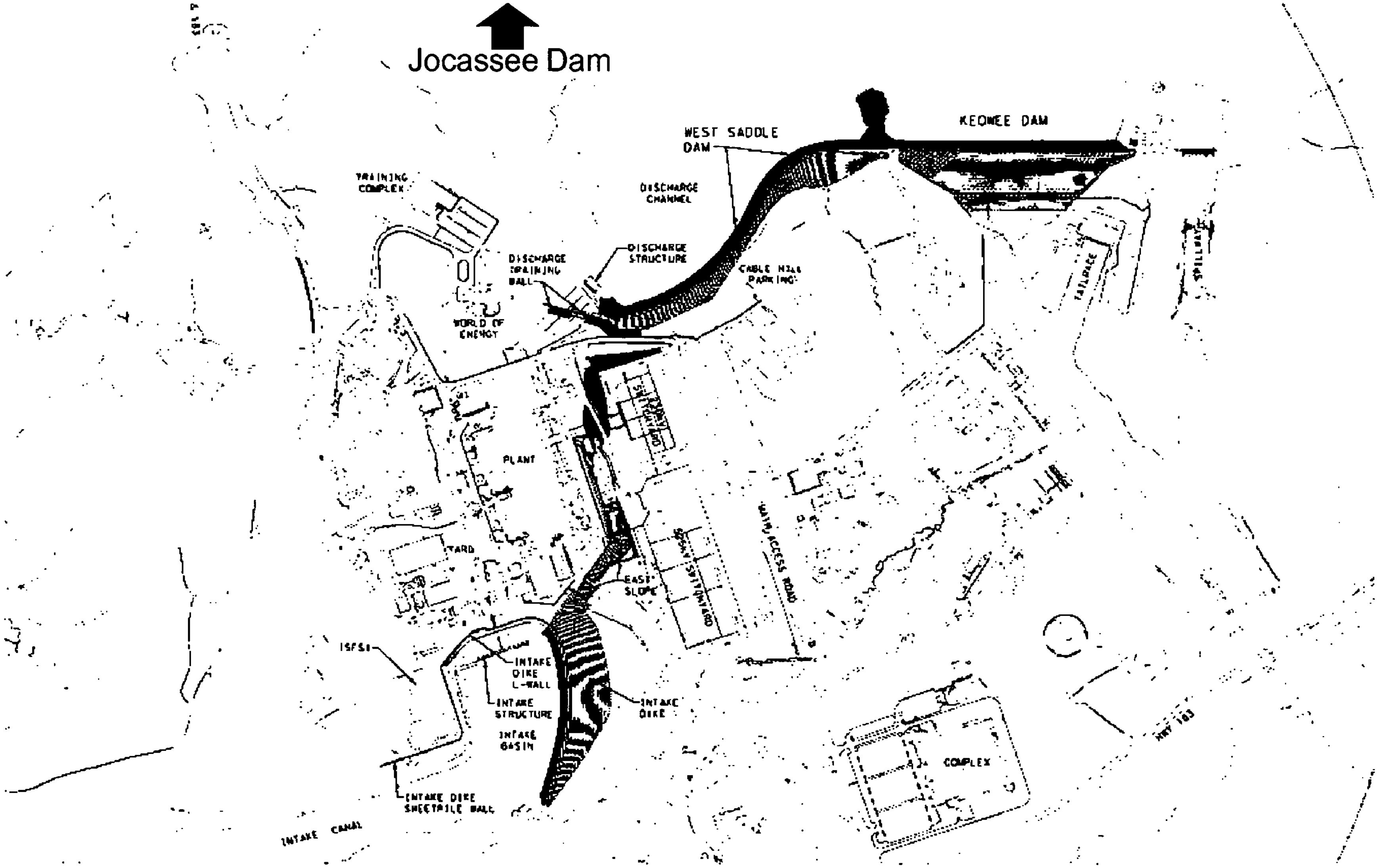
Modification Update

<u>Protect Required Systems, Structures, and Components</u>

- Two Engineering/Construction firms currently on site have completed Phase 1 conceptual designs
- <u>Phase 1</u> Flood Mitigation Design Options
    - Flood Mitigation Wall along eastern perimeter
    - Discharge Diversion Wall to protect the yard
    - Intake Canal Entry Barrier/Gate to protect the yard & preserve water in the intake canal
    - Hardening Keowee dam and West saddle dam surface with Roller Compacted Concrete (RCC)
    - Improve Jocassee dam to change failure characteristics (cutoff wall)
    - Combinations of the above options
- <u>Phase 2</u> Detailed Implementation Design – Fukushima hazard reevaluation design inputs needed to start Phase 2.

Modification Update

(Oconee Nuclear Site Plan View)



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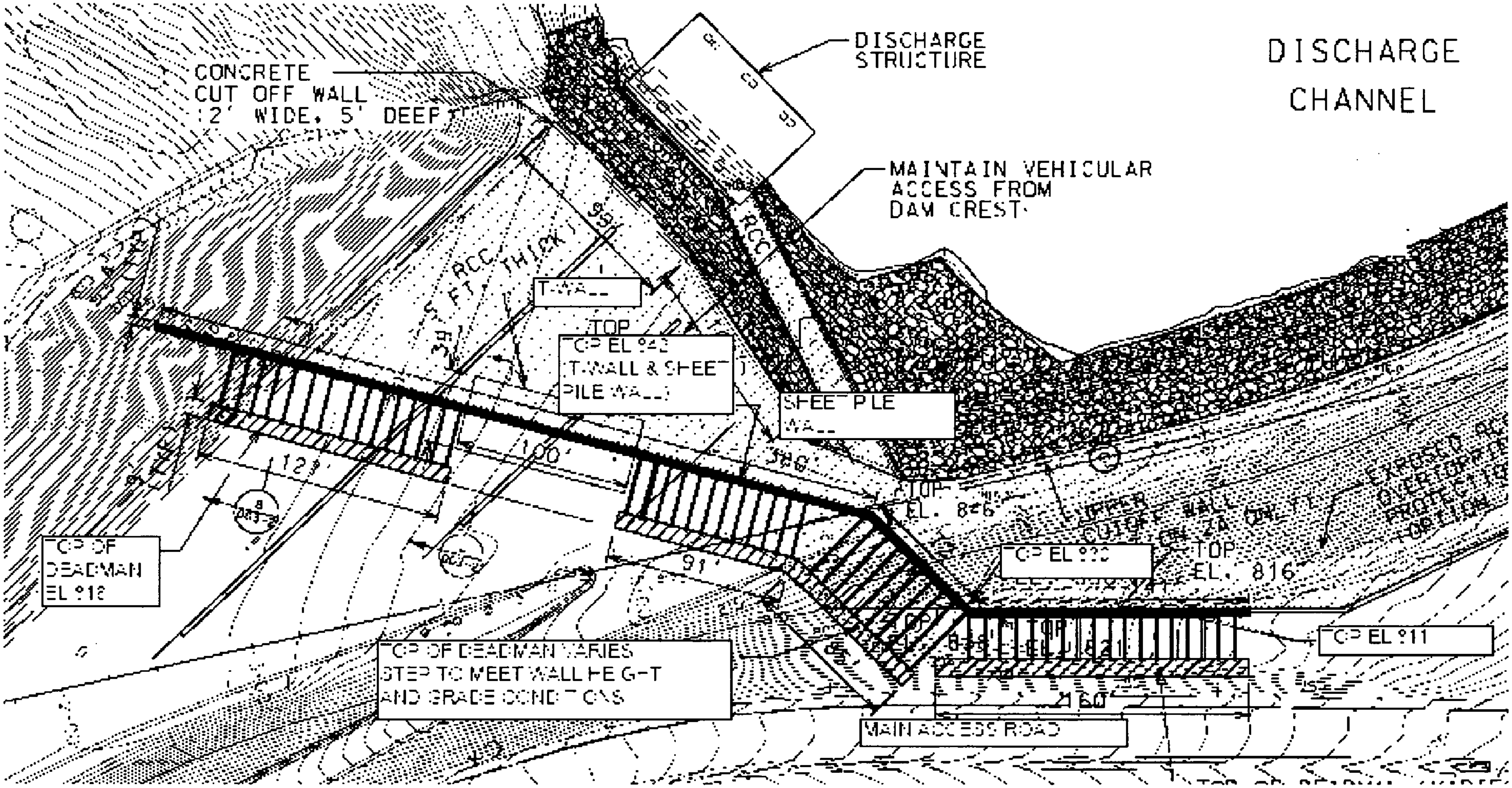
Duke Energy

Discharge Diversion Wall



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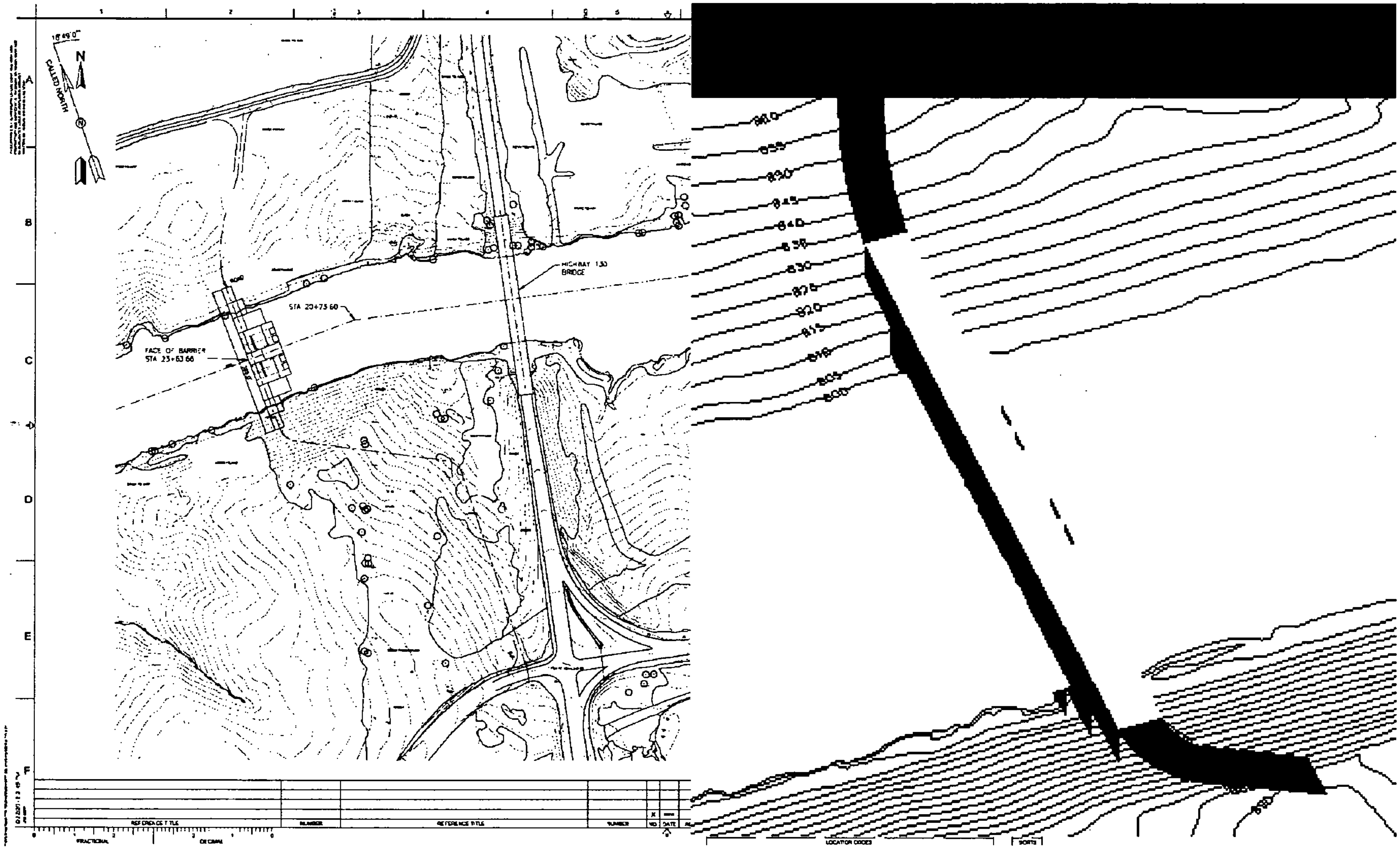
Duke Energy

Intake Canal Barrier



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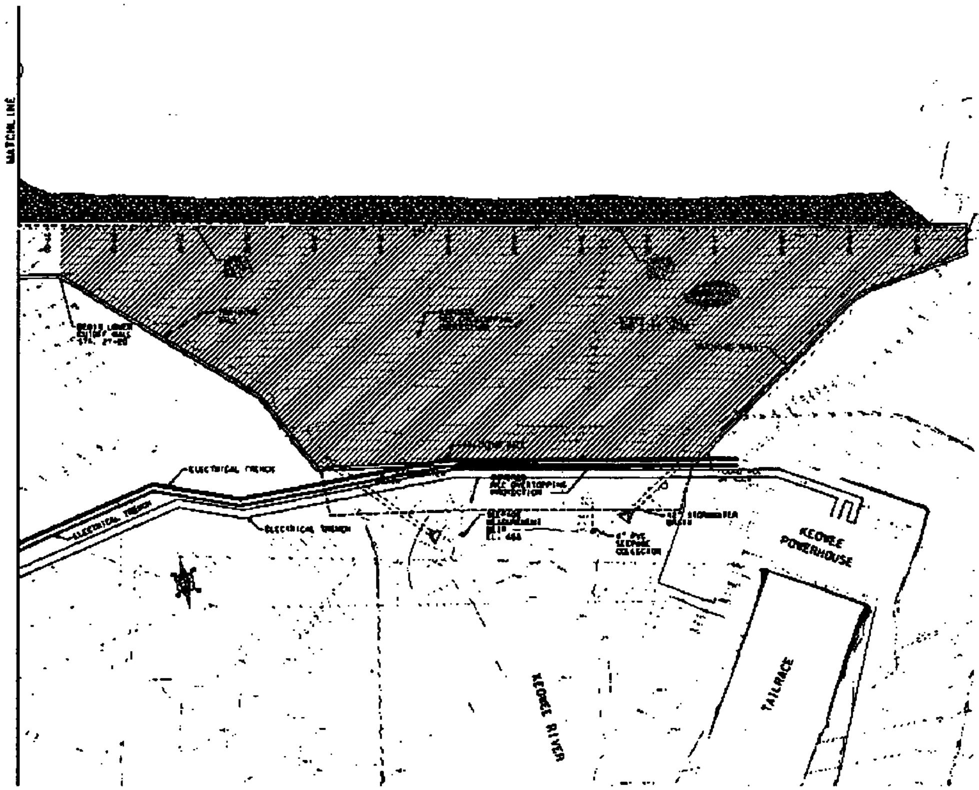
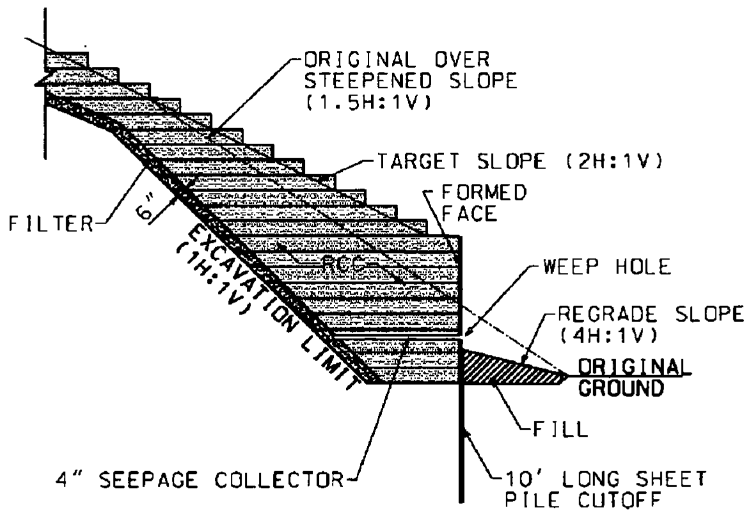
Hardening Keowee & West Saddle Dam





Jocassee Cut Off Wall

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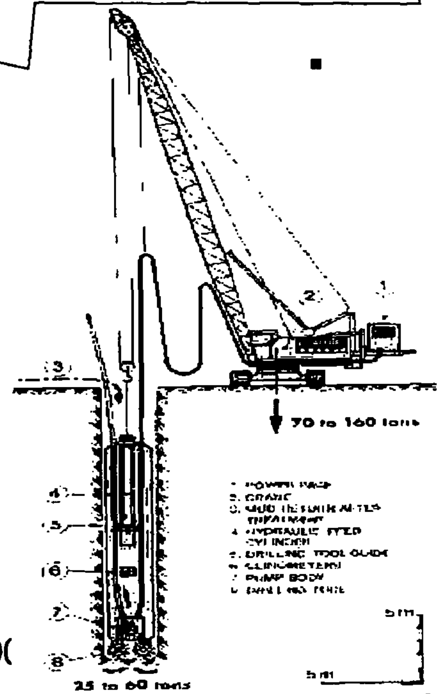
Example Application : Wells Dam (FERC)

•1,130' long concrete dam section; 2,300' west embankment and 1,030' east embankment
•Embankments – permeable zones over miscellaneous alluvium and very dense till
•Hydropower Dam
•Owner – Douglas County Public Utilities Department
•Located in Washington State

Features

•Purpose: to prevent piping through permeable core materials
•30-in thick panel wall
•Cutoff Depth – 80' to 223'
•Cutoff Length – 849'
•Completed in 1991



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For Information Only

Fukushima Impacts

- January 2011 NRC SER on parameters and bounding analysis
- **March 11, 2011 Tsunami and Fukushima Event**
- April 2011 Duke provided list of proposed modifications and schedule
- October 2011 Duke RAI responses submitted
- November 2011 NUREG/CR-7046 published
- **March 6, 2012 NRC Transferred GI-204 to Fukushima**
- **March 12, 2012 NRC Fukushima Order and 50.54(f) issued referencing NUREG/CR-7046 for required flooding hazard reevaluation**
- **May 11, 2012 NRC Prioritization Response Dates issued**
- May 2012 NRC RAI's - Wall Codes & Standards, Seismic criteria
- **March 12, 2013 50.54(f) Flooding Re-evaluation Report due (Oconee designated by NRC as Category 1 site)**

Conclusions

- Oconee specific SER was issued January 2011 (prior to NUREG/CR-7046 and Fukushima)
- Fukushima flood reevaluation is for a larger set of flooding hazards using new standards (NUREG/CR-7046 with NEI/NRC expanded guidance)
- Duke believes the SER has been overtaken by the Fukushima 50.54(f) required flooding evaluation which requires updated, comprehensive hazard analysis
- Oconee should lead in flood hazard evaluation – including Fukushima flooding reevaluation
- As a Year 1 response site, Oconee's Fukushima response is due in 9 months
- Duke needs direction on whether the SER flooding hazard analysis bounds the Fukushima 50.54(f) flooding analysis
- The interim CAL flooding mitigation actions will remain in place and additional margin is gained through implementation of FLEX N+1 this year