January 27, 2006

MEMORANDUM TO: Catherine Haney, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

FROM: Charles E. Ader, Director ***/RA/***
Division of Risk Analysis and Applications
Office of Nuclear Regulatory Research

SUBJECT: TRANSMITTAL OF FINAL ASP ANALYSES

This memorandum provides the final results of eight Accident Sequence Precursor (ASP) analyses of operational events or conditions which occurred at various plants during fiscal years 2003 and 2004. Note that this is the first batch of ASP analyses transmitted under the improved review processes described in my memorandum of December 1, 2005 (ML053270411).

Transmittal to licensees requested. We are requesting NRR/DORL to send the final ASP analyses to the appropriate licensees for information. The ADAMS Accession Number for each analysis is provided in the Enclosure.

Final ASP analyses to be transmitted. The Enclosure summarizes the final analyses of the events and conditions:

- Both Emergency Diesel Generators (EDGs) unavailable for 28 hours at Kewaunee in February 2003 (LER 305/03-002). The ASP analysis calculated a mean change in core damage probability (ΔCDP) of $3x10^{-6}$.

- Automatic reactor scram due to momentary loss of offsite power at Peach Bottom Unit 3 in September 2003 (LER 277/03-004). The ASP analysis calculated a mean conditional core damage probability (CCDP) of $3x10^{-6}$.

- Emergency Core Cooling System piping voids may have prevented fulfillment of a safety function at Palo Verde Units 1, 2, & 3 in July 2004 (LER 528/04-009). The ASP analysis calculated a mean ΔCDP of $1.4x10^{-5}$.

- Loss of High Pressure Coolant Injection System function as a result of an inoperable flow controller at Peach Bottom 3 in March 2004 (LER 278/04-001). The ASP analysis calculated a mean ΔCDP of $1.6x10^{-6}$.

- Scram due to loss of offsite power at Dresden Unit 3 and subsequent inoperability of the standby gas treatment system for Units 2 and 3 in May 2004 (LER 249/04-003). The ASP analysis calculated a mean CCDP of $2.8x10^{-6}$.

- Unanalyzed conditions due to inadequate separation of associated circuits at Shearon Harris reported between 2002 and October 2005 (LER 400/02-004). The ASP analysis calculated a mean ΔCDP of 9×10^{-6}.

- Sticking slider contact on a switch disables start of RHR pump at Sequoyah 1 in July 2004 (IR 327/04-010). The ASP analysis calculated a mean ΔCDP of 4.4×10^{-7}.

Sensitive information. The detailed ASP analyses referenced the Enclosure have been reviewed according to SECY-04-0191 and can be released to the public.

If you have any questions about the individual analyses, please contact the staff member cited for that analysis in the Enclosure. For questions concerning the transmittal letter or the ASP Program, please call Gary DeMoss (415-6225).

Enclosure:
Summaries of Final ASP Analyses

- Unanalyzed conditions due to inadequate separation of associated circuits at Shearon Harris reported between 2002 and October 2005 (LER 400/02-004). The ASP analysis calculated a mean ΔCDP of $9x10^{-6}$.

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Enclosure:
Summaries of Final ASP Analyses

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OERAB RF
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DPassehl, RIII (SRA)
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RBywater, RIV (SRA)
MRunyan, RIV (SRA)

FBower, RI (SRI)
DSchroeder, RI (RI)
SBurton, RIII (SRI)
PHiggins, RIII (RI)
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DSmith, RIII (SRI)
DRamadan, RIII (RI)

DOCUMENT NAME: G:\DRAA\MEMO–FINAL ASP TO DORL (3 EVENTS IN 2003 AND 4 EVENTS IN 2004).WPD

OAR in ADAMS? (Y or N) Y ADAMS Accession No.: ML060240525 Template No. RES- 006
Kewaunee Accession No.: ML060240375
Peach Bottom Accession No.: ML060240384
Palo Verde 1,2,3 Accession No.: ML060240389
Peach Bottom 3 Accession No.: ML060240394
Dresden Unit 3 Accession No.: ML060240407
Shearon Harris Accession No.: ML060240435
Sequoyah 1 Accession No.: ML060240421
Package Accession No.: ML060240240
Publicly Available? (Y or N) Y Date of Release to Public: N/A Sensitive? N

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SUMMARIES OF FINAL ASP ANALYSES

Both Emergency Diesel Generators (EDGs) unavailable for 28 hours at Kewaunee (February 2003) The condition was reported by LER 305/03-002-00, dated April 28, 2003, and documented in NRC Inspection Report No. 50-305/03-08, dated January 26, 2004.

Condition summary: At 0239, on February 25, EDG 'A' was removed from service to perform scheduled periodic maintenance. During the daily required test on EDG 'B' (at 0017 on February 26), the diesel failed to start. On February 26, 2003, at 0107 hours, a manual reactor shutdown was initiated, according to Technical Specifications, due to both EDGs being unavailable. The total time that both EDGs were simultaneously out of service was approximately 28 hours.

Results: This event was modeled as a conditional assessment with both EDGs unavailable for 28 hours. The ASP analysis calculated a mean change in core damage probability (ΔCDP) of $3x10^{-6}$ with 5% and 95% uncertainty bounds of $2x10^{-7}$ and $9x10^{-6}$, respectively.

SDP/ASP comparison: This event was screened out during Phase 1 of the SDP (loss of a single mitigating system train for less than the allowed outage time specified in the Technical Specifications). According to the Phase 1 SDP procedure (IMC 0609A), mitigating system trains that are taken out of service for testing and maintenance are not considered unavailable for the purposes of the evaluation.

Comments: NRR/DSSA and Region III comments are addressed in the analysis. The licensee did not comment on the preliminary analysis.

The ASP analysis can be found at ML060240375. If you have any questions about the analysis, please contact Chris Hunter (415-4127).

Automatic reactor scram due to momentary loss of offsite power at Peach Bottom Unit 3 (September 2003). This event is documented in LER 277/03-004 dated November 7, 2003.

***Event Summary*:** On September 15, 2003, Peach Bottom Unit 3 experienced a brief loss of offsite power (LOOP) to the emergency buses and tripped. The momentary LOOP was the result of a lightning strike approximately 35 miles northeast of the site. All four emergency diesel generators automatically started. The High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems were manually started to maintain reactor water level. Reactor pressure was controlled using the Main Steam Safety Relief Valves (SRVs).

Other conditions, failures, and unavailable equipment were reported:

- EDG E2, which serves both units, tripped on low jacket water coolant pressure approximately 1 hour after the LOOP occurred.
- Main steam isolation valves on both units closed causing the loss of the power conversion system in the short term.

- Five SRVs opened in response to the reactor scram with SRV D initially failing to reclose after lifting. The valve closed 15 minutes later without operator action.

Results: The ASP analysis calculated a mean CCDP of $3x10^{-6}$ for Unit 3 with 5% and 95% uncertainty bounds of $1x10^{-7}$ and $1x10^{-5}$, respectively.

SDP/Augmented Inspection Team (AIT) Comparison: The calculation performed shortly after the event to support the AIT resulted in a CCDP of $3x10^{-5}$ for Unit 3. This is significantly higher than the values calculated by the ASP analyses for several reasons. First, the ASP analysis used SPAR models with updated equipment unavailability data published in late 2004. For this event the most important change in equipment unavailability data was an order of magnitude decrease in SRV failure probability. Second, the ASP analysis credited the possibility of using secondary plant systems, which were reported to be available, to mitigate the potential accident sequences. The final SDP finding was White for conditional assessment of diesel failure at Unit 3.

Comments: NRR/DSSA and Region I comments are addressed in the analysis. The licensee did not comment on the preliminary analysis.

The ASP analysis can be found at ML060240384. If you have any questions about the analysis, please contact Chris Hunter (415-4127).

Emergency Core Cooling System piping voids may have prevented fulfillment of safety function at Palo Verde Units 1,2, & 3 (July 2004). This event is documented in LER 528-2004/009 dated September 28, 2004 and Inspection Report 328/2004-009 dated July 5, 2005.

Condition Summary: On July 30, 2004, the licensee became aware of a voided condition in a section of ECCS recirculation piping in all 3 Units, such that both ECCS trains in a Unit were affected. Specifically, the section of recirculation piping between the closed inboard containment isolation valves and the associated train sump recirculation check valves (downstream of the outboard containment isolation valves) were void of water for both ECCS trains. The relevant air volume was about 100 ft^3 per train. Of this volume, approximately 90 ft^3 of air was caught between the inboard and the outboard containment isolation valves, with the remaining 10 ft^3 existing between the outboard containment isolation valve and the train sump recirculation valve.

The voided condition apparently existed since 1992, when a modification to the recirculation piping leak testing procedure was put in place without proper analysis. This modification involved draining the recirculation piping section, each time the leak test with demineralized water was completed. In addition, even prior to 1992, quarterly stroke testing of the containment isolation valves left part of the suction piping in the partially voided condition. Thus, the analysis considered the one year period prior to discovery of condition, as per ASP program convention.

This event was modeled as a conditional assessment with the recirculation function unavailable following a transient or a small LOCA. The unavailability of the recirculation function following a medium LOCA (MLOCA) was treated with a probability distribution developed through an expert elicitation process.

Results: The ASP analysis calculated a mean ΔCDP of 1.4×10^{-5}, with 5% and 95% uncertainty bounds of 3.7×10^{-6} and 4.4×10^{-5}, respectively.

SDP/ASP comparison: This condition was analyzed as YELLOW finding by a Phase 3 SDP analysis. The licensee and the NRC staff agreed that the recirculation function was not available following a transient or small LOCA. However, based on laboratory testing and analysis, the licensee stated that the recirculation function was available (i.e., nominal equipment unavailabilities) following a MLOCA. The NRC staff working on the SDP analysis reviewed the licensee's testing and analysis, and concluded that the recirculation function is proven to be unavailable following a medium LOCA. The SDP Phase 3 analysis calculated a ΔCDP of in the mid-10^{-5} and issued an YELLOW finding. The ASP analysis took a different approach to the recirculation function unavailability following a MLOCA, and used a recently developed simplified expert elicitation approach. The result was a factor of 3 lower ΔCDP in the ASP analysis. The ASP analysis is consistent with the SDP's YELLOW analysis finding.

The ASP analysis can be found at ML060240389. If you have any questions about the analysis, please contact Gary DeMoss (415-6225).

Loss of High Pressure Coolant Injection System function as a result of an inoperable flow controller at Peach Bottom 3 (March 2004). This event is documented in licensee event report LER 278/04-001, dated April 30, 2004.

***Condition summary*:** On 3/17/2004, at approximately 12:35 hours, during the performance of a routine quarterly surveillance test for the High Pressure Coolant Injection (HPCI) system, Peach Bottom personnel discovered that HPCI was inoperable. During performance of the surveillance test, the HPCI turbine could not achieve a speed above 1000 rpm and no significant discharge pressure was observed (e.g., no flow was delivered).

The HPCI system along with the Reactor Core Isolation Cooling (RCIC) system are two systems credited for providing high pressure makeup to the reactor pressure vessel (RPV) during various transient and small LOCA type events.

Other flow related components on the HPCI system were evaluated and found to be in an acceptable condition. Other similar flow controllers (both HPCI and RCIC) on Units 2 and 3 were evaluated for extent of condition concerns and determined to be operable.

Results: The ASP analysis calculated ΔCDP of 1.6×10^{-6} .

The ASP analysis can be found at ML060240394. If you have any questions about the analysis, please contact Jeffery Mitman (415-0191).

Scram due to loss of offsite power at Dresden Unit 3 and subsequent inoperability of the standby gas treatment system for Units 2 and 3 (May 2004). This event is documented in licensee event report LER 249/04-003, dated October 29, 2004.

Condition summary: On May 5, 2004, Dresden Unit 3 was at full power and Dresden Unit 2 was shut down. Offsite power Line 1223 in the Unit 3 switchyard ring bus was out of service for scheduled maintenance. Operations personnel were implementing a switching order which cross-tied the Unit 2 and Unit 3 switchyard ring busses to provide an alternative source of power to the Unit 3 Reserve Auxiliary Transformer (RAT). Operations personnel manually opened Switchyard Breaker 8-15 in accordance with the switching order. However, when the 'A' and 'B' phases of Breaker 8-15 opened, the 'C' phase of Breaker 8-15 failed to fully open within the required time frame. This failure caused current imbalances in both the Unit 2 and Unit 3 switchyard ring busses. The current imbalances in the switchyard first resulted in a Unit 3 automatic scram due to a turbine load reject. The continued current imbalances then caused a loss of power to the Unit 3 RAT which resulted in a Unit 3 LOOP to the safety-related Emergency Core Cooling System (ECCS) Busses.

The licensee declared an Unusual Event in accordance with the Emergency Plan and exited the Unusual Event approximately two and a half hours later following the restoration of offsite power to one of onsite safety-related electrical buses.

Results: This event was modeled as a LOOP initiating event. The ASP analysis calculated a CCDP of 2.8×10^{-6}.

SDP/ASP Comparison: The SDP Phase 1 assessment found that the performance deficiency would have resulted in low risk significance.

The ASP analysis can be found at ML060240407. If you have any questions about the analysis, please contact Erul Chelliah (415-6186).

Unanalyzed condition due to inadequate separation of associated circuits at Shearon Harris (December 2002). This event is documented in licensee event report LER 400/02-004 (revisions 00 through 09), dated February 28, 2003 through January 4, 2006.

Condition summary: On December 20, 2002, inspection of the Harris Nuclear Plant (HNP) Safe Shutdown Analysis (SSA) identified that postulated fires could cause spurious actuation of certain valves. Valve actuation in the flowpath for the protected Charging/Safety Injection Pump (CSIP) could result in loss of the pump. Similarly, simultaneous spurious closure of multiple valves in the flowpaths to the Reactor Coolant Pump (RCP) seals could result in the loss of RCP seal cooling. HNP identified other postulated fires could cause spurious actuation of certain valves or components that could also result in the conditions described above, transfer of Refueling Water Storage Tank (RWST) inventory to the containment recirculation sump, transfer of some Reactor Coolant System (RCS) inventory to containment, inadvertent pressurizer spray, or could potentially impact indication used to monitor Reactor Coolant System pressure and level. The ASP analysis of this LER, which was originally dated February 28 2003, is being issued at this time because the LER has been revised nine times with the latest dated January 4, 2006.

The cause of these conditions is inadequate original Safe Shutdown Analysis of certain conductor-to-conductor interactions.

Results: The ASP analysis calculated a (ΔCDP) of $9x10^{-6}$ for the 14 fire areas considered in the ASP analysis.

SDP/ASP comparison: The risk significance of this condition has also been analyzed under the Significance Determination Process (SDP), for one of the eight fire areas identified at that time, 1-A-BAL-B. The result was a GREEN finding with a delta CDF of $7.8x10^{-7}$, based on a postulated spurious operation events that could lead to Small LOCA at power. The ASP analysis had an expanded scope caused by multiple revisions to the LER and considered the fourteen fire areas as defined in the revised LER.

The ASP analysis can be found at ML060240435. If you have any questions about the analysis, please contact Selim Sancaktar (415-8184).

Sticking slider contact on a switch disables start of RHR pump 1A at Sequoyah 1(July 2004) . This event is documented in Inspection Report 50-327/2004-004 dated October 25, 2004.

Condition Summary: On July 7, 2004 during a 3-month NRC inspection completed on September 25, 2004, while both Units were at 100% power, the RHR 1A pump failed to start during a surveillance test. The failure was caused by the pump breaker, due to binding of the Siemens breaker mechanism operated cell slide assembly (a wear out failure mode). Pump 1B was not susceptible to this failure mode as it does not use the same type of mechanism (the breaker is from another manufacturer). The same type of breaker is used in other emergency core cooling systems (both trains). The licensee had a similar occurrence with the Siemens breaker slide assembly in April 2004 (not necessarily on this pump) and performed inadequate followup inspection which led to the above failure event. After the event, all Siemens breakers were replaced with breakers from other manufacturers.

The inoperability condition of RHR pump 1A persisted from June 23, 2004, the last time the breaker was observed to perform successfully, until July 8, 2004, when the breaker was replaced (for 15 days).

Results: This event was modeled as a conditional assessment with the RHR pump 1A unavailable for 15 days. The ASP analysis calculated a mean ΔCDP of $4.4x10^{-7}$, with 5% and 95% uncertainty bounds of $8.3x10^{-8}$ and $1.7x10^{-6}$, respectively.

SDP/ASP comparison: This event was analyzed as WHITE event by a Phase 3 SDP analysis in the fall of 2004. In the winter of 2004, a significant revision to the SPAR model and the associated equipment reliability data was published. The ASP analysis used the same condition analysis approach as the SDP and the newer SPAR model, which resulted in ΔCDP that is a factor of about 3 lower than that of the SDP. The difference between the ASP and SDP analyses is the result of ongoing improvements to the SPAR model.

The ASP analysis can be found at ML060240421. If you have any questions about the analysis, please contact Gary DeMoss (415-6225).