November 1, 2006

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

FROM: Farouk Eltawila, Director */RA/*
Division of Risk Assessment and Special Projects
Office of Nuclear Regulatory Research

SUBJECT: TRANSMITTAL OF FINAL ASP ANALYSES

REFERENCE: Memorandum to James E. Lyons, Director, NRR/DRA and others, from Farouk Eltawila, Director, RES/DRAA, "Changes to the Accident Sequence Precursor (ASP) Program", August 9, 2006, ADAMS Accession No. ML061950028

This memorandum provides the final results of nine Accident Sequence Precursor (ASP) analyses of operational events or conditions which occurred at various plants. As described in the referenced memorandum, RES implemented several process changes to the ASP program. These changes were part of a continuing effort to increase ASP program efficiencies, to improve the timeliness of ASP evaluations, and to achieve better coordination among the ASP, the Significance Determination Process (SDP), and the Management Directive (MD) 8.3 programs. These are the first analyses transmitted under the new process. The analyses transmitted by this memorandum are for plant initiating events for which there were either no SDP or MD 8.3 evaluations or for cases where the evaluation methods are different because of the different objectives of the SDP, MD 8.3 and ASP programs. Where there were SDP evaluations (in three events), the SDP findings were based on evaluations of the performance deficiency, whereas the ASP results were based on the occurrence of the initiating event, i.e., the plant trip, compounded by equipment unavailability where applicable. The SDP and ASP results are therefore not comparable. These differences have been discussed with NRR and Regional staff.

In accordance with the referenced memorandum, since these events are lower risk events ($<1\times10^{-4}$) formal peer review is not requested. We are transmitting a summary of the analysis results to NRR and the regions, and requesting NRR to transmit the analyses to the affected licensees for their information.

The completion of ASP analyses documented in this memorandum is part of the overall effort which led to the completion of all ASP analyses for FY04 and FY05 events. This memorandum also transmits an analysis of the Catawba Loss of Offsite Power of May 2006 (FY06) that was performed in conjunction with the Region II Senior Reactor Analysts.

***Transmittal to licensees requested.*** We are requesting NRR/DORL to send the final ASP analyses to the appropriate licensees for information. This memorandum will be publically released. The ASP analyses and results will be made publically available when they are transmitted to the respective licensees. References to the ASP analyses are provided in this memorandum and a model for the transmittal letter can be found in ADAMS at ML062710403. Contact Gary DeMoss (415-6225) of my staff if any additional assistance is required.

***Final ASP analyses to be transmitted.*** The final ASP analyses to be transmitted are listed below. The enclosure to this memorandum summarizes the events and conditions, and the results of the ASP analyses.

- Automatic reactor trip followed by safety injection at Vogtle Unit 2, November 2004 (LER 425/04-004). The ASP analysis calculated a mean conditional core damage probability (CCDP) of $3 \times 10^{-6}$.

- Loss of offsite power during Hurricane Katrina at Waterford, August 2005 (LER 382/2005-004). The ASP analysis calculated a mean CCDP of $2 \times 10^{-6}$.

- Manual reactor scram due to moisture separator reheater drain line failure at Hope Creek, December 2004 (LER 354/04-010). The ASP analysis calculated a mean CCDP of $3 \times 10^{-6}$.

- Reactor trip due to loss of a non-vital 120V instrument bus at River Bend, December 2004, (LER 458/04-005). The ASP analysis calculated a mean CCDP of $3 \times 10^{-5}$.

- Reactor trip due to feedwater pump trip caused by maintenance personnel error at Columbia, June 2005, (LER 397/05-004). The ASP analysis calculated a mean CCDP of $1 \times 10^{-5}$.

- Automatic reactor trips due to loss of offsite power at Catawba Units 1 and 2, May 2006 (LER 413/06-001). The ASP analysis calculated mean CCDPs of $9 \times 10^{-5}$ for Unit 1 and $6 \times 10^{-5}$ for Unit 2.

***Final ASP analyses that were previously sent for comment.*** We are also requesting that NRR send out the following ASP analyses to the affected licensees. These ASP analyses were previously issued to licensee and staff for review and, where applicable, comments have been addressed. The Enclosure summarizes the final analyses of the following events and conditions:

- Dual–unit loss of offsite power during Hurricane Jeanne at St. Lucie Units 1 & 2, September 2004 (LER 335/04-004). The ASP analysis calculated a mean conditional core damage probability (CCDP) of $1 \times 10^{-5}$. No comments were received.

- Automatic reactor scram due to loss of offsite power with condenser vacuum pump inoperable and subsequent failure of instrument air at Grand Gulf, April 2003 (LER 416/03-002). The ASP analysis calculated a mean CCDP of $1.3 \times 10^{-6}$. NRR and licensee comments are addressed in the final analysis.

- Excessive steam demand — reactor trip due to low steam generator water level after feed pump trip at Calvert Cliffs 2, January 2004 (LER 318/04-001). The ASP analysis calculated a mean CCDP of $1.2 \times 10^{-5}$. Licensee comments are addressed in the final analysis.

***Sensitive information.*** The detailed ASP analyses referenced in the Enclosure have been reviewed in accordance with 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 (301-415-6225).

Enclosure:
Summaries of Final ASP Analyses

- Automatic reactor scram due to loss of offsite power with condenser vacuum pump inoperable and subsequent failure of instrument air at Grand Gulf, April 2003 (LER 416/03-002). The ASP analysis calculated a mean CCDP of $1.3 \times 10^{-6}$. NRR and licensee comments are addressed in the final analysis.

- Excessive steam demand — reactor trip due to low steam generator water level after feed pump trip at Calvert Cliffs 2, January 2004 (LER 318/04-001). The ASP analysis calculated a mean CCDP of $1.2 \times 10^{-5}$. Licensee comments are addressed in the final analysis.

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Enclosure:
Summaries of Final ASP Analyses

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MEMORANDUM DATED: 11/1/06

SUBJECT: TRANSMITTAL OF FINAL ASP ANALYSES

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Enclosure 1

## SUMMARIES OF FINAL ASP ANALYSES

**Automatic reactor trip followed by safety injection at Vogtle Unit 2 (November 2004).** This event is documented in licensee event report (LER) 425/04-004, dated August 8, 2005. Additionally, Region II conducted an Integrated Inspection and issued Inspection Report (IR) 05000424/2004006 and 05000425/2004006 on January 26, 2005.

***Condition summary.*** On November 20, 2004 at 11:40 a.m., with the plant operating at 100% power, testing of the solid state protection system led to a spurious reactor trip. Subsequent to the trip, the Loop 2 $T_{avg}$ instrument channel failed in its full power value, leading to a full-open demand for the steam dump (turbine bypass) valves (SDVs). The opening of these valves, which have a capacity of 40% of full power steam flow, led to a rapid drop in reactor coolant system (RCS) temperature and pressure. The operators responded by initiating a Main Steam Isolation. The decrease in RCS pressure was, however, sufficient to cause automatic indication of safety injection. After the RCS pressure had restored to the normal range, the operators terminated SI at 11:55 a.m. and the unit was in normal operation at hot standby. Post event review indicated that, other than the failed $T_{avg}$ instrument, all systems and equipment performed normally.

***Results:*** This initiating event resulted in a point estimate in conditional core damage probability (CCDP) of $2.8 \times 10^{-6}$ . An uncertainty analysis for this operating condition was also performed resulting in a mean CCDP $2.9 \times 10^{-6}$ with 5% and 95% uncertainty bounds of $2 \times 10^{-7}$ and $1.1 \times 10^{-5}$ respectively.

***SDP/ASP comparison:*** Region II conducted an Integrated Inspection and issued Inspection Report (IR) 05000424/2004006 and 05000425/2004006 on January 26, 2005. The IR concluded that the finding is greater than minor because it affected the human performance attribute of the initiating events cornerstone which resulted in an unplanned reactor trip. The finding is of very low safety significance (Green) because it did not contribute to the likelihood that any mitigation equipment or functions would not be available. This finding also involved the cross-cutting aspect of human performance. This violation is being treated as an non-cited violation in accordance with Section VI.A of the NRC Enforcement Policy. For the ASP analysis, an Initiating Event assessment was conducted, thus the SDP results are not directly comparable to the ASP results. The SDP evaluated at the human performance over a period of time. The ASP analysis evaluated the CCDP risk associated the initiating event and minor problems following the event.

The ASP analysis can be found at ML062710030. If you have any questions about the analysis, please contact Peter Appignani (301-415-6857).

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**Loss of offsite power in Mode 4 during Hurricane Katrina at Waterford (August 29, 2005)**. This event is document in LER 382/05-004, dated October 27, 2005, and Inspection Report IR382-2005-004, dated November 8, 2005.

***Condition Summary***: The loss of offsite power (LOOP) occurred on August 29, 2005 at 07:59 while the plant was shutdown (mode 4) in preparation for hurricane conditions. At the time, the site was experiencing sustained tropical storm winds of 48 miles per hour. The hurricane Katrina was making its landfall on the Louisiana coastline. The loss of power was a result of grid instabilities which were caused by damage and effects of the hurricane. The plant experienced voltage spikes prior to the loss of power, which eventually caused declaration of offsite power inoperable some time before the event, at 06:24. At 07:45, the instrument air pressure was lost due to lowering grid voltage. When the LOOP occurred, both EDGs started and loaded their respective emergency bus loads. SDC-A (shutdown cooling loop A), which was removing the decay heat prior to the event, was manually connected by 08:15 and continued to operate to remove the decay heat. The EDGs operated throughout the event. Eventually, the plant entered Mode 5, as a precaution, on September 1, 2005. After grid evaluations, offsite power was declared operable at 23:21 on September 1, 2005 for train A and at 22:20 on September 2, 2005 for train B. Plant startup commenced on September 9, following successful completion of NRC's and FEMA's restart readiness inspection. The plant was synchronized to the grid on September 13, 2005.

***Results:*** This event was modeled as a LOOP initiating event during mode 4. The ASP analysis calculated a mean conditional core damage probability (CCDP) of $2.1 \times 10^{-6}$ with 5% and 95% uncertainty bounds of $1.8 \times 10^{-7}$ and $6.9 \times 10^{-6}$, respectively. Placing the plant in Mode 4 before the hurricane lowered the risk by about an order of magnitude.

***SDP/ASP Comparison:*** The SDP did not probabilistically evaluate this event.

The ASP analysis can be found at ML062710035. If you have any questions about the analysis, please contact Gary DeMoss (301-415-6225).

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**Manual reactor scram due to moisture separator reheater drain line failure at Hope Creek (October 2004).** This event is documented in licensee event report LER 354/04-010, dated December 9, 2004.

Region I conducted a Special Inspection and issued Inspection Report (IR) 05000354/2004013 on February 4, 2005. The significance determinations and enforcement review panel (SERP) and Enforcement Board met to discuss the findings and the Notice of Violation was issued for this event under EA-05-001 on February 28, 2005.

***Event summary.*** On October 10, 2004 at 17:39 hours a pipe failure occurred in the Moisture Separator Reheater Drain Line of the Hope Creek Nuclear Generating Station. A power reduction to 80% power was initiated at 17:59 due to reports of a steam leak in the Turbine Building. At 18:14, the Reactor Recirculation Pumps were reduced to minimum speed and the reactor was manually scrammed. Operators initially began to reduce RPV pressure using the Turbine Bypass Valves to allow for use of the Condensate and Feedwater Pumps for RPV makeup. Due to the continued degradation of condenser vacuum, the Reactor Feedwater Pumps all tripped. At this point, RPV makeup and pressure control was provided by manually initiating the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. At 18:17 hours, the control room supervisor directed the reactor operator to close the Turbine Bypass Valves. As the bypass valves closed, RPV level decreased causing an isolation signal.

With the RCIC system injecting into the RPV and water levels trending upwards, HPCI injection was terminated. Condenser vacuum continued to degrade and operators manually closed the Main Steam Isolation Valves (MSIVs) and Main Steam Line Drain Valves prior to automatic closure on low condenser vacuum. Following MSIV closure, HPCI was placed in the pressure control mode. While placing HPCI in the pressure control mode, operators were initially unable to open the HPCI full flow test line MOV. At 18:31 hours, the A and B Residual Heat Removal (RHR) trains were placed in the Suppression Pool Cooling mode. At 18:46 hours, RPV level dropped and the RPV Level 3 SCRAM setpoint was again actuated. RCIC flow was manually increased to restore water levels above the RPV Level 3 scram setpoint. Following this, at approximately 18:50 hours the feedwater system was restarted (with flow being provided by the Condensate pumps) with the startup feedwater level control valve set in the automatic mode.

At 20:48 hours the operators commenced a plant cooldown using HPCI, RCIC and Safety/Relief Valves (SRVs). This effort was complicated by repeated trips which occurred in the HPCI barometric vacuum pump, a non-safety support system which maintains a slight vacuum on the HPCI steam discharge line. This led operators to secure the HPCI system and rely on a combination of SRVs and RCIC to maintain RPV level and depressurize the system. At approximately 22:03 hours the RPS Level 3 was again reset and feedwater startup level control valve setpoint raised from 25" to 35" (with flow being provided by the condensate pumps). The plant reached cold shutdown conditions at 05:09 hours on October 12, 2004.

***Results:*** This initiating event resulted in a conditional core damage probability (CCDP) of $3.4 \times 10^{-6}$. An uncertainty analysis for this operating condition resulted in a mean CCDP of $3.4 \times 10^{-6}$ with 5% and 95% uncertainty bounds of $4.7 \times 10^{-8}$ and $1.2 \times 10^{-5}$ respectively.

***SDP/ASP comparison.*** The result of the Significance Determination Process (SDP) analysis was a WHITE finding. The white finding was based on a SDP Phase 3 assessment assuming an unavailability of 25 days and estimated an increase in core damage frequency of (ΔCDF) 1.8 $\times10^{-6}$ for internal events. Since the SDP did a ΔCDF calculation and the ASP did an initiating event assessment (i.e., calculated the CCDP), the two analytic results are not numerically comparable. The analytic assumptions and dominant risk contributors are similar in the two analyses.

The ASP analysis can be found at ML062710037. If you have any questions about the analysis, please contact Gary DeMoss (301-415-6225).

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**Reactor trip due to loss of a Non-Vital Instrument Bus at River Bend (December 2004).**
This event is documented in licensee event report LER 458/04-005. Region IV conducted a Special Inspection and issued Inspection Report (IR) 05000458/2004005 on February 14, 2005.

**Event Summary.** On December 10, 2004, at 1:17p.m. with the unit operating at 100% power, a capacitor shorted causing loss of power to the 120V Instrument Bus VBN-PNL01B1. This resulted in a loss of control power to the feedwater regulating valves, and a downshift in the speed setting for the B Reactor Recirculation pump, as well as a loss of indication to several instruments powered by the Instrument Bus. The loss of control power to the feedwater regulating valves resulted in them “locking-up” in place. This resulted in an overfeed condition and the additional cold water caused in increase in thermal neutron power. The lowering recirculation system flow caused the Average Power Rate Meter (APRM) power-to-flow setpoint to lower. The reactor then automatically tripped on high APRM power level.

With the main feedwater regulating valves locked-up in their full power position, excess feedwater was delivered to the reactor pressure vessel (RPV) causing a high level in the RPV. This resulted in an automatic high RPV water level trip of the running feedwater pumps. In response to this, operators initiated Reactor Core Isolation Cooling (RCIC) to maintain post-trip reactor water level, which should have lowered rapidly had the feedwater regulating valves not been locked up in the 100% flow position before the feedwater pumps tripped. Immediately after RCIC was initiated, it shut down in response to the high RPV level trip signal. An alarm actuated indicating presence of water in the RCIC turbine exhaust line drain trap.

Also, complicating the operators’ decision making process was the loss of the only valid indication of reactor water level: the upset range indicator, which was directly lost due to the loss of 120V Instrument Bus VBN-PNL01B1 and the unexpected RCIC alarms. This resulted in a situation in which there were totally contradictory level indications presented to the operators from the main control board. As a result, when the RPV level returned on-scale on the wide range and narrow range reactor water level instruments, the operators used the High Pressure Core Spray (HPCS) for reactor water level control. This complicated the operators’ response to the event, since HPCS draws water from condensate storage and adds water to the suppression pool when it is not used to add water to the RPV. As a result, the operators had to start the RHR system in the suppression pool cooling to facilitate rejecting water from the suppression pool to radwaste to maintain suppression pool level below high level action points.

The 120V Instrument Bus VBN-PNL01B1 was shifted to an alternate power source by placing the UPS in the manual bypass mode. The feedwater regulating system was restored to service at approximately 4:57 p.m. CST on the same day, and the HPCS was secured and returned to its normal standby configuration.

***Results:*** This initiating event resulted in a CCDP of $2.7 \times 10^{-5}$. An uncertainty analysis for this operating condition resulted in a mean CCDP of $2.8 \times 10^{-5}$ with 5% and 95% uncertainty bounds of $3.5 \times 10^{-6}$ and $9.1 \times 10^{-5}$ respectively.

**SDP/ASP Comparison.** No potentially significant non-compliance findings were identified, thus no SDP risk analysis was performed.

The ASP analysis can be found at ML062710038. If you have any questions about the analysis, please contact Erul Chelliah (301-415-6186).

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**Reactor trip caused by a feedwater pump trip at Columbia (June 2005).** This event is documented in licensee event report (LER) 397/05-004, dated August 22, 2005. Additionally, Region II conducted an Integrated Inspection and issued Inspection Report (IR) 397/2005005 on February 13, 2006.

***Event summary.*** On June 23, 2005, Columbia Generating Station was in Mode 1, with the reactor operating at approximately 23 percent power. At 1346 PDT, an automatic scram occurred due to a low water level condition in the reactor vessel. The low reactor water level condition was caused by an inadvertent loss of reactor feedwater pumps (RRW-P-1B) due to a false low suction pressure signal caused by human error during planned maintenance activities. Control room operators entered appropriate Emergency Operating Procedures and stabilized the plant following the reactor scram. Plant systems responded as designed with the exception of Reactor Core Isolation Cooling (RCIC), as discussed below.

The RCIC system was manually started to restore reactor water level and was later manually tripped. The system had to be reset locally due to tripped mechanical overspeed trip linkage. During two subsequent attempts to restart RCIC, the pump tripped on low suction pressure. Operators were then able to successfully start RCIC with the flow controller in manual. A time delay has been added to the RCIC low suction pressure trip to resolve this issue.

***Results:*** This initiating event resulted in a point estimate in conditional core damage probability (CCDP) of $1.2x10^{-5}$ . An uncertainty analysis for this operating condition was also performed resulting in a mean CCDP $1.3x10^{-5}$ with 5% and 95% uncertainty bounds of $2.1x10^{-7}$ and $5.5x10^{-5}$ respectively.

***SDP/ASP comparison:*** A Green finding was identified because Energy Northwest failed to maintain the design capability of the reactor core isolation cooling system consistent with Final Safety Analysis Report specified design functions. During conditions where the reactor core isolation cooling system suction header pressure was reduced to that provided by the condensate storage tanks, the reactor core isolation cooling pump would inadvertently trip due to low suction pressure as a result of a momentary hydraulic perturbation in the system which occurred as the system was starting up. A Phase 2 and Phase 3 evaluation were performed. A senior reactor analyst conducted the Phase 3 evaluation using a Standardized Plant Analysis Risk model simulation of the failure of the reactor core isolation cooling pump to automatically start and inject into the reactor coolant system. The analyst concluded that the core damage frequency associated with the event was $4.3 \times 10^{-8}$ . Since the ASP analyzed this as an initiating event, the results are not directly comparable to the SDP results.

The ASP analysis can be found at ML062710039. If you have any questions about the analysis, please contact Gary DeMoss(301-415-6225).

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**Loss of offsite power at Catawba Units 1 and 2 (May 20, 2006).** This event is documented in LER 413/06-001, dated July 19, 2006, and Augmented Inspection Team (AIT) Report 05000413/2006-009 and 05000414/2006-009, dated June 29, 2006.

***Event Summary (from AIT report)*.** On May 20, 2006, at 2:01 p.m., an electrical fault in the Catawba 230kV switchyard caused several power circuit breakers (PCB's) to open resulting in a loss of all offsite power (LOOP) and a subsequent reactor trip of both units from 100 percent power. All reactor trip breakers opened as expected and all control rods fully inserted into the core on the two units. Both main turbines tripped upon receipt of the P4 protective signals following the reactor trips. Control room operators responded to the event using normal, abnormal and emergency operating procedures.

Following the LOOP, the four (4) emergency diesel generators started and supplied power to the 4.16kV vital busses. Designated vital equipment was re-energized in accordance with the plant design through the diesel generator load sequencers. During the LOOP events, two pressurizer power-operated relief valves (PORVs) in Unit 1 cycled for a total of 62 times; one PORV in Unit 2 cycled 35 times. The PORVs on both units operated as designed to control primary plant pressure.

Power was restored to the Unit 2 6.9kV busses at 8:27 p.m. on May 20, 2006, and to the Unit 1 6.9kV busses at 8:40 p.m. Due to existing lockouts on the 1A and 2B main transformers, full realignment of breakers to provide offsite power to the vital busses and securing of all four diesel generators did not occur until approximately 1:10 a.m. on May 21, 2006.

***Results:*** This event was modeled as an initiating event LOOP. For Unit 1, this event resulted in a mean CCDP of $9 \times 10^{-5}$ with 5% and 95% uncertainty bounds of $8 \times 10^{-6}$ and $3 \times 10^{-4}$ respectively. For Unit 2, this event resulted in a mean CCDP of $6 \times 10^{-5}$ with 5% and 95% uncertainty bounds of $6 \times 10^{-6}$ and $2 \times 10^{-4}$ respectively. The two dominating sequences that contributed to 75% of the risk in both units involved a postulated stuck-open pressurizer PORV and failure to restore offsite power to vital loads. The reason for the difference between the Units is the number of PORV lifts.

***SDP/ASP Comparison:*** The SDP did not probabilistically evaluate this event.

The ASP analysis can be found at ML062710061. If you have any questions about the analysis, please contact Don Marksberry (301-415-6378.

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***Dual–unit loss of offsite power during Hurricane Jeanne at St. Lucie Units 1 & 2 (September 2004)***. This event is documented in licensee event report LER 335/04-004, dated November 24, 2004.

***Condition summary:*** At 23:56 hours on September 25, 2004, a dual-unit loss of offsite power (LOOP) occurred at the St. Lucie site. Earlier that day both units commenced an orderly shutdown to prepare for the arrival of Hurricane Jeanne. At the time of the LOOP, the site was experiencing hurricane force winds with both units in Mode 4. The emergency diesel generators started and safe shutdown loads (with the exception of the 1B intake cooling water pump) were sequenced as designed. Offsite power was restored to both units by 11:03 hours on September 26, 2004 .

The LOOP was caused by two independent electrical faults associated with the wind–driven salt contamination in the westward eye wall of Hurricane Jeanne. However, with both units shutdown, the switchyard design protection scheme for the main generators effectively reduces electrical power redundancy to the startup transformers.

***Results:*** This event was modeled as a LOOP initiating event leading to loss of RHR cooling during mode 4. The ASP analysis calculated a mean conditional core damage probability (CCDP) of $1 \times 10^{-5}$.

***SDP/ASP Comparison:*** The SDP did not probabilistically evaluate this event.

The ASP analysis can be found at ML062710041. If you have any questions about the analysis, please contact Selim Sancaktar (415-8184).

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***Automatic reactor scram due to loss of offsite power with condenser vacuum pump inoperable and subsequent failure of instrument air, Grand Gulf (April 2003)***
This event is documented in licensee event report (LER) 416/03-002, dated 23 June, 2003, and Inspection Report 50-416/2003-02 dated 23 July, 2003

***Condition summary*:** On April 14, 2003, ENTERGY Mississippi removed 500 kV Breaker J5204 from service in the switchyard at Grand Gulf Nuclear Station by opening disconnects J5203 and J5205 in order to repair an internal gas leak. On the morning of April 24, 2003, work was continuing on Breaker J5204 when high winds in the switchyard caused Disconnect Switch J5205 to close, creating a line-to-ground fault, which isolated all incoming 500 kV power to Service Transformer 21 (ST21). Coincident with this, failures in the *ENTERGY Mississippi* carrier transmission fault relaying system caused both 500 kV power sources from the Baxter-Wilson Station and the Franklin Station switchyards to be isolated from the plant switchyard. The Grand Gulf generator temporarily remained on the 500 kV east bus powering ST11. Because of this 500 kV electrical grid transient, the plant turbine generator control system sensed a full load rejection and responded by initiating a turbine control valve fast closure and automatic reactor trip. All control rods inserted as designed. Loss of transformer ST21 resulted in a bus undervoltage on the Division I, II and III ESF busses that resulted in the start of the Division I, II and III emergency diesel generators. Reactor water level 2 was reached, MSIVs closed, and the High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) systems started as designed. Operators stabilized and maintained reactor pressure vessel (RPV) water level according to procedures. Reactor pressure was maintained by the proper cycling of the Safety/Relief Valves (SRVs). Approximately a half hour into the event, suppression pool cooling was initiated using Residual Heat Removal(RHR) systems.

Essential AC electrical buses were properly supplied throughout the duration of the event by the operation of the emergency diesel generators. Had any of the emergency buses become de-energized due to the failure of a diesel, the buses could be transferred back to offsite sources. The transition of the plant to cold shutdown was complicated by the loss of the Instrument Air System which required approximately 2 hours to restore. The Instrument Air System supports several systems credited in the plant emergency procedures for alternate emergency decay heat removal and containment cooling. These systems include: CRD flow (in the enhanced flow control mode), Fire Water makeup to the RPV, and Containment Venting for containment heat removal. Had the normal operation of HPCS, RCIC, and RHR systems failed and the need to utilize alternate RPV makeup and containment cooling, these alternate measures would not have worked until Instrument Air was restored.

***Results:*** This event was modeled as an initiating event loss of offsite power (LOOP) with complications caused by the additional loss of Instrument Air. The ASP analysis calculated a mean conditional core damage probability (CCDP) of $1.3 \times 10^{-6}$ with 5% and 95% uncertainty bounds of $1 \times 10^{-7}$ and $4 \times 10^{-6}$, respectively.

***Review Comments:*** NRR and licensee comments are addressed in the analysis. Several licensee comments resulted in changes to the text. However, the more substantive licensee comments were not incorporated into the probabilistic analysis because the licensee's assumed ability to continuously recirculate saturated water from the suppression pool to the RPV following containment failure and maintain long term core cooling has not been conclusively

demonstrated by any analysis which the ASP program has been able to review. No quantitative changes were made to the analysis.

**SDP/ASP Comparison.** The SDP did not probabilistically evaluate this event.

The ASP analysis can be found at ML062710045. If you have any questions about the analysis, please contact Eli Goldfeiz (301-415-5539).

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***Excessive steam demand–reactor trip due to low steam generator water level after a feed pump trip at Calvert Cliffs 2 (January 2004)***. This event is documented in Licensee Event Report (LER) 318/04-001-00, dated January 23, 2004, Special Inspection Report No. 05000317/2004008 and 05000318/2004008, dated July 29, 2004, and Supplemental Inspection Report 05000318/2005006, dated February 11, 2005.

***Condition summary:*** At 15:26 on January 23, 2004, Calvert Cliffs Nuclear Power Plant (CCNPP) Unit 2 tripped from 100 percent power, initiated by the Reactor Protection System due to low steam generator water level caused by an erroneous overspeed trip signal on 22 Steam Generator Feed Pump (SGFP). The control room operator could not reset the SGFP, and the reactor was tripped upon an automatic reactor trip signal.

The Turbine Bypass Valves (TBVs) and Atmospheric Dump Valves (ADVs) opened as designed, but the "quick open" signal did not clear due to the failure of a relay in the reactor regulating circuit. The open valves (turbine bypass and atmospheric dump) resulted in overcooling of the Reactor Coolant System (RCS) and also generation of a Safety Injection Actuation Signal (SIAS) and a Steam Generator Isolation Signal (SGIS) resulting in a loss of normal heat removal.

About three minutes after the reactor trip, both Main Steam Isolation Valves (MSIVs) were shut upon receipt of an SGIS, isolating steam flow through the TBVs and thereby slowing the rate of RCS cooldown. Approximately six minutes later, the operations crew took control of the ADVs through the Auxiliary Shutdown Panel, terminating the RCS overcooling and depressurization.

During the recovery, a large in surge of subcooled water into the RCS caused by full charging with a relatively high RCS heat up, cooled the pressurizer, lowering the RCS pressure to produce a second SIAS.

***Results***: The Final ASP analysis calculated a CCDP of $4.1 \times 10^{-5}$ with 5% and 95% uncertainty bounds of $2.2 \times 10^{-7}$ and $1.5 \times 10^{-5}$ respectively. This is about a factor of 3 lower than the preliminary CCDP of $1.2 \times 10^{-5}$.

***SDP/ASP comparison.*** The result of the SDP analysis was a WHITE finding. The SDP Phase 3 assessment used the Calvert Cliffs Standardized Plant Analysis Risk (SPAR) model, Rev 3i, dated November 2001, which was modified to incorporate human action dependencies relative to maintaining AFW water source and conducting once through cooling (feed and bleed) and also included model revisions that more accurately represent the secondary side of the plant. Condition assessment has been conducted by SDP assuming that the K7 relay of the Reactor Regulating System was in failure condition for 240 days. The result of the analysis is an estimated increase in core damage frequency (ΔCDF) of $2 \times 10^{-6}$ for internal events. Additionally, the results of the external events analysis indicated that external events were not a significant contributor to ΔCDF.

The ASP analysis used the Calvert Cliffs SPAR model, Revision 3.12, dated February 2, 2005. The SPAR model was extensively modified to more accurately evaluate this event. Both initiating event and condition assessments were performed to evaluate the risk significance.

The result of the ASP analysis is an estimated increase in ΔCDF of $5x10^{-5}$ for the same condition evaluated for the SDP. The ASP model contains a more elaborate treatment of the potential for an over steam demand event than the SDP model. Accordingly, the ASP analysis obtained different dominant contributors for the initiating event due to differences in the models as well as model assumptions.

**Licensee Comments and Resolutions**. Approximately 80% (9.7E-06) of the original risk calculated by the preliminary ASP was due to Sequence 47 which assumes core damage upon failure of both main steam isolation valves (MSIVs) to close and failure of the once through core cooling (OTCC) human action. The licensee pointed out that failure of the MSIVs will not prevent use of the auxiliary feedwater (AFW) system. Additionally, the overcooling caused by the event and high pressure safety injection (HPSI) injection increases the likelihood of success for OTCC. The licensee provided simulator runs and analysis to support these assertions. This lowered the total risk estimate by a factor of about 3.

The ASP analysis can be found at ML062710050. If you have any questions about the analysis, please contact Peter Appignani (415-6857).

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