March 2, 2007

Mr. Gary Van Middlesworth
Vice-President
Duane Arnold Energy Center
3277 DAEC Road
Palo, IA 52324-9785

SUBJECT: DUANE ARNOLD ENERGY CENTER
NRC INSPECTION REPORT 05000331/2006008(DRS)

Dear Mr. Van Middlesworth:

On February 12, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Duane Arnold Energy Center. The enclosed integrated inspection report documents the inspection findings which were discussed on February 12, 2007, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents two NRC-identified findings of very low safety significance (Green). Both of these NRC-identified findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the violations were entered in your corrective program, the NRC is treating the issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Duane Arnold Energy Center.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA by J. Lara Acting For/

Ann Marie Stone, Chief
Engineering Branch 2
Division of Reactor Safety

Docket No. 50-331
License No. DPR-49

cc w/encl: J. Stall, Senior Vice President, Nuclear and Chief Nuclear Officer
R. Helfrich, Senior Attorney
M. Ross, Managing Attorney
W. Webster, Vice President, Nuclear Operations
M. Warner, Vice President, Nuclear Operations Support
R. Kundalkar, Vice President, Nuclear Engineering
J. Bjorseth, Site Director
D. Curtland, Plant Manager
S. Catron, Manager, Regulatory Affairs
Chief Radiological Emergency Preparedness Section, Dept. Of Homeland Security
D. McGhee, State Liaison Officer

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-331
License No:	DPR-49
Report No:	05000331/2006008(DRS)
Licensee:	Florida Power and Light Energy Duane Arnold, LLC
Facility:	Duane Arnold Energy Center
Location:	Palo, Iowa
Dates:	March 31, 2006, through February 12, 2007
Inspectors:	P. Lougheed, Senior Engineering Inspector J. Neurauter, Senior Engineering Inspector
Approved by:	Ann Marie Stone, Chief Engineering Branch 2 Division of Reactor Safety

Enclosure

SUMMARY OF FINDINGS

IR 05000331/2006008; 03/31/2006 - 02/12/2007; Duane Arnold Energy Center; Other Activities

This report covers an announced followup inspection of an unresolved item identified in NRC Inspection Report 05000331/2006002. The inspection was conducted by two Region III engineering specialists.

A. Inspector-Identified Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" having very low safety significance. Specifically, the licensee failed to identify and correct a condition adverse to quality regarding a pressure significantly over the design value recorded on a high pressure coolant injection system vent line during a surveillance test on February 11, 2006, until prompted by the NRC. As corrective actions, the licensee performed calculations to assess the issue. The primary cause of this violation was related to the cross-cutting area of human performance because the licensee failed to use a systematic process when faced with an unexpected plant condition during a special test.

  This issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Disposition Screening," because the finding was associated with the Mitigating Systems cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events. Specifically, the pressure pulse exceeded the design pressure rating of the piping. Without evaluation, the licensee could not ensure the availability and reliability of the over-stressed vent piping to withstand normal operation. The issue was of very low safety significance based on a Phase 1 screening in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations. (Section 4OA5.2)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee's calculation to show that the existing feedwater piping system configuration met the acceptance criteria of ASME Boiler and Pressure Vessel Code, Section III, Appendix F used a method of analysis that did not evaluate the dynamic effect of impact forces as specified by the design basis piping code, ANSI B31.1, "Power Piping." As corrective actions, the licensee performed calculations to assess the issue. The primary cause of this violation was related to the cross-cutting area of human performance because the licensee did not have adequate guidance on how to evaluate the dynamic effect of impact for variable spring hanger determined to exceed their available seismic travel.

  The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," because it affected the Mitigating Systems Cornerstone attribute of design control, and if left uncorrected, the finding could become a more significant safety

concern. Specifically, the failure to evaluate the dynamic effect of impact as required by the ANSI B31.1 design basis code in similar operability calculations could result in exceeding the ASME Section III, Appendix F acceptance limits used to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The issue was of very low safety significance based on a Phase 1 screening in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations. (Section 4OA5.2)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES

Cornerstones: Mitigating Systems and Barrier Integrity

4OA5 Other Activities

a. Inspection Scope

The inspectors performed an on-site and in-office review of the licensee's analyses associated with the discovery of the potential for a steam void in the high pressure coolant injection (HPCI) system.

b. Findings

1. (Open) URI 05000331/2006002-03, "Potential Inoperability of the High Pressure Coolant Injection System"

Background: As described in Licensee Event Report 05000331/2005-004, on September 29, 2005, the licensee attempted to vent the HPCI injection piping, but was unable to obtain a steady stream of water over a protracted period. The licensee concluded that the cause of the high temperatures at the injection valve was an energy transport process that included turbulent penetration energy transport between the feedwater line between and the check valve, V23 -0049; natural convection between the check valve and the closed HPCI injection valve, MO-2312; and conduction through the discs of the check and injection valves. The end result was elevated HPCI temperatures on the pump discharge side of the injection valve. The licensee concluded that this created a steam void in the high point of the piping between this valve and the pump discharge. The presence and size of this steam void created a potential for a pressure transient in the HPCI piping during routine surveillance tests and during an actual HPCI injection.

The licensee implemented immediate compensatory actions including: (1) periodic venting of the volume; (2) removal of insulation; (3) raising of the minimum condensate storage tank (CST) level to 15 ft or maintaining the keep fill system in service; and (4) monitoring of injection line temperatures. With these compensatory actions in place, the temperature readings at the time of the inspection were below saturation conditions indicating minimal void formation. The licensee concluded the system was currently operable. The inspectors did not take exception to this conclusion.

With respect to past operability (prior to compensatory actions), the licensee initiated an operability evaluation documented in corrective action program (CAP) document 038124 and completed several supporting calculations and analyses. The licensee concluded the HPCI system was operable but non-conforming.

The inspectors reviewed the operability evaluations, CAPs and supporting calculations and identified a number of non-conservative assumptions which had a cumulative effect rather than canceling each other out. The inspectors also identified discrepancies between information presented in the licensees calculations, the routine surveillance strip charts and the special test performed on February 11, 2006.

Non-verified Assumption

The licensee evaluated the impact of the elevated HPCI temperatures. The inspectors identified a non-conservative assumption in the licensee's calculations. Specifically, the inspectors noted that the licensee did not use the calculated maximum void size in the hydraulic calculations. The inspectors noted that in calculation 0078-0503-01, the licensee determined the size of the possible steam void. The licensee postulated that, prior to the insulation being removed, the maximum size bubble downstream of the injection valve was the entire horizontal section of the pipe from the elbow to the injection valve or 1.7 ft^3. The licensee further determined that the maximum size bubble existing after the insulation was removed depended upon the CST level and ranged from 0.9 ft^3 to 1.2 ft^3.

Instead of using these calculated values in calculations MPR-2880 and 0078-0503-02, the licensee defined a maximum system pressure peak of approximately 400 pounds per square inch (psi). The licensee then adjusted the void size and added an air pocket to achieve this desired impact pressure. The 400 psi value was based on licensee observation of a 400 psi peak which appeared on several surveillance strip charts. The licensee postulated that this pressure peak was indicative of a void collapse, and that the void collapse was independent of void size, based on there being a concurrent HPCI pump suction void forming and collapsing.

The inspectors determined that this assumption could not be supported by the licensee's special test, by actual void collapse events at other facilities or by any scientific literature such as NUREG/CR-5220, "Diagnosis of Condensation-Induced Waterhammer." The inspectors also determined that the methodology of NRC-approved Electric Power Research Institute (EPRI) TR-113594, "Resolution of Generic Letter 96-06 Waterhammer Issues" would be applicable, although the methodology was developed specifically to address voiding in service water piping following a loss of offsite power. However, the licensee did not use either of these NRC-approved methodologies and did not provide verification for their non-standard approach.

Impact of Altered HPCI System Conditions

The inspectors noted that the licensee verified their calculational model through performance of a special test on February 11, 2006. However, the HPCI system conditions when the special test was performed did not correspond to the conditions prior to October 2005 that were being evaluated by the operability determinations. The calculations were being performed to support the operability determinations. The inspectors noted the following major differences that would impact the size of a steam void present during the special test:

- Prior to March 2005, the licensee had not vented the HPCI injection line. The interval between venting decreased from quarterly to monthly to biweekly over the period from March 2005 to October 2005. Frequent venting would ensure no air or non-condensible gases were entrained in the HPCI system.

- Prior to October 2005, the horizontal portion of the HPCI injection line just upstream of the injection valve MO-2312 was insulated. This insulation was removed in October 2005. Removal of the insulation would increase the heat transfer out of the HPCI system, resulting in overall lower HPCI temperatures. The lower HPCI temperatures were generally at or below saturation temperature thus minimizing the existence of a steam void during normal operation.

- Prior to October 2005, the CST level was allowed to fluctuate, as long as it was kept above the Technical Specification minimum of 8 feet. The preferred level would have allowed a steam void to form during normal operation. In October 2005, the licensee raised the level of the CST such that the pressure in the HPCI system was at saturation pressure for the observed temperatures, eliminating or reducing steam void formation.

The inspectors ascertained that the licensee's calculations asserted that these differences were accounted for by the time between the two peaks on the surveillance strip charts. However, the licensee did not provide verification of this assertion. Furthermore, the licensee's calculation did not provide any analysis to show that the special test results were conservative and bounded previously existing situations.

Evaluation of Pressure Data from Surveillance Strip Charts

The licensee informed the inspectors that the surveillance strip charts showed two anomalies from what was expected during a normal pump start up. The existence of these anomalies led the licensee to conclude that the strip charts demonstrated the maximum pressure peak that occurred when the steam void collapsed and that maximum pressure reached was the same regardless of void size. The first anomaly, according to MPR 2880, occurred at approximately 0.4 seconds following the turbine start and was a small pressure rise followed by a small pressure drop. The second anomaly was rapid rise to a peak of approximately 400 psig, followed by a sharp drop. The licensee explained that further, less sharp, pressure increases and decreases were the normal pump starting curve.

The inspectors reviewed a number of different strip charts from various DAEC surveillances. The inspectors noted that the strip charts showed considerable pen movement such that, for the majority of the charts, it was difficult to identify where the points were that the licensee indicated existed. In some cases there was no identifiable pressure drop which supposedly indicated the suction void formation and collapse and steam void formation. In other cases there would be two or three peaks in the vicinity of the one the licensee concluded was the steam void collapsing. In one case, the inspectors were unable to ascertain any initial peak, drop or rise; instead the curve was basically smooth, similar to the one the licensee stated was a startup curve at low feedwater temperatures.

Special Test Time Anomalies

The inspectors identified anomalies with the special test data as provided in the licensee's test report. First, the inspectors ascertained that the licensee had not synchronized the start times of the various pressure transducers and accelerometers used during the test. Although one graph presenting the pump suction and discharge pressures showed approximately 1.3 seconds worth of data and recorded a pump discharge peak of 400 psi occurring at approximately 0.42 seconds, another graph for the same location showed 20 minutes worth of data and documented that a peak of 400 psi occurred at 710 seconds. The test report did not provide any information as to whether these were the same peaks or how the zero points were chosen.

The inspectors also noted that the pressure transducer located in the steam tunnel identified sharp pressure peaks. The first graph documented 1.3 seconds worth of data and showed two pressure peaks occurring at 0.67 and 0.73 seconds and having magnitudes of approximately 1830 and 1940 psi. The second graph documented 20 minutes worth of data and showed a peak of approximately 1940 psi occurring at approximately 460 seconds. Again, there was no information other than the magnitude of the peaks to correlate the two graphs and no information provided as to how the zero points were chosen. Furthermore, the 20-minute graph showed a 500 psi peak occurring approximately 6 seconds after the 1940 psi peak and a third distinct peak of approximately 450 psi occurring around 755 seconds. These additional peaks were not analyzed by the licensee.

The inspectors were unable to determine any correlation between the graphs showing the pump suction and discharge pressures and the graphs showing the steam tunnel pressures. Finally, because the test report did not indicate pump start time on any of the graphs or in any of the associated text, the inspectors were unable to correlate the test times with a routine surveillance start.

Special Test Pressure Anomalies

In addition to the time anomalies, the inspectors noted that the special test report graph which depicted 1.3 seconds worth of pump suction and discharge pressure data showed oscillating discharge pressures reaching as low as -136 psi following the 400 psi peak. Through discussions with the instrument vendor, the inspectors learned that the pressure transducer used registered abrupt changes from a base pressure and that the oscillations most likely indicated that pressure had rapidly changed. The inspectors noted that the special test report indicated that all pressures were pressure pulses or changes from whatever the static or transient pressure happened to be at the time of the pulse. However, the special test report did not indicate any test data which provided either the total pressure or the static or transient pressure, much less correlating the peak pressures to the total pressure or static pressure. Because of the lack of correlation on the times, the inspectors also noted that the base pressure could not be inferred from a routine surveillance. Additionally, the inspectors noted that any such inference would be extremely inaccurate due to the scale and pen response time of the routine surveillance recorders.

Effect of Test Anomalies on Calculation

Section 5.4 of MPR 2880 contained Figure 5.8, “Recorded Discharge Pressure Change Compared to SYSFLO Results.” Section 7.1 of 0078-0503-02 contained Figure 11, “Recorded Pump Discharge Pressure Change versus STP.INP Results.” These two figures were identical. The inspectors determined that the discharge pressure data shown in both these figures came from the special test report graph depicting 1.3 seconds worth of pump suction and discharge pressure data.

Both calculations concluded that the model and special test showed the same rise time and a similar pressure pulse magnitude. Both calculations noted that the model predicted a slightly higher peak pressure and as such was conservative. The text of both calculations stated that, because the pump start times were unknown for the test data, the times where the pressure increase began were synchronized in the figure. Additionally, in calculation 0078-0503-02, although not in MPR 2880, it was noted that the recorded pressure data was increased by 127 psi. The rationale given in calculation 0078-0503-02 was that the additional pressure was necessary because the data was from the pre-spike pressure and not zero pressure; however, the licensee did not provide any information as to how or from where the value of 127 psi was obtained. The inspectors again noted that because the times were not actually synchronized it would not be possible to accurately compare the routine surveillance strip charts to the special test to determine a base pressure.

The inspectors questioned the validity of the conclusion that the pressure rise was similar between the model and the test and that the model magnitude was similar but conservatively higher. As discussed above, there was no documented rationale for the zero point on the 1.3 seconds worth of data, as documented by the licensee in both the calculations. Therefore, it did not appear to be appropriate to draw a conclusion that the model successfully predicted a pressure peak similar in rise and magnitude based on arbitrary synchronization of the test data and the model. Furthermore, again as discussed above, there was no documented information in the test report about either the total pressure or the static or transient pressure that needed to be added to the peak pressure. Therefore, it did not appear to be appropriate to raise the test data by a specific amount that allowed the conclusion to be drawn that the pressure magnitudes were similar, or that the model was conservative.

Effect of Air on Calculational Model

The inspectors noted that calculation 0078-0503-02 stated that an air accumulator of 0.18 ft^3 was added to reduce the void collapse rate. The Office of Nuclear Reactor Regulation safety evaluation report which accepted EPRI TR-113594 identified that the presence of an air void would tend to cushion the impact of the water slug, reducing the magnitude of the waterhammer pressure pulse. The safety evaluation report stated that evaluations were to verify that the uncushioned velocity and pressure were no more than 40 percent greater than the cushioned values. If they were greater, than licensees were to certify that pipe failure probability assumptions remained bounding. The inspectors noted that no sensitivity studies were done to evaluate the impact of the added air accumulator. Furthermore, the inspectors noted that the HPCI system was being vented on a biweekly basis at the time of the special test, so that any air voids would be removed. Therefore, the inspectors questioned whether the addition of the air accumulator was conservative.

Special Test Not Representative of Either Normal Surveillance or Injection

The inspectors determined that the special test would not have provided verification of the licensee's assumption that impact pressure was independent of void size. The inspectors evaluated the pressure and temperature conditions under which the special test was performed, as compared to a routine surveillance and an actual injection, as indicated below:

- Special Test on February 11, 2006: This test occurred after the compensatory actions were taken, such that no steam void should have existed prior to the test. The inspectors determined that the measured temperatures just upstream of the injection valve were approximately 228°F and 216°F and that the injection valve was not cycled prior to the surveillance. These temperatures were near but less than the saturation temperature for the pressure achieved by having the CST at 15 feet. Therefore, the inspectors determined the line was water-filled before the test return line was opened. While a pressure drop would occur when the test return line was opened to the CST atmosphere, and some of the fluid would flash to steam, the inspectors determined that any steam void would be extremely small, and might be contained within the high point vent piping. The inspectors also noted that no air would have been present in the system, due to the biweekly venting.

- Routine Surveillance Test Prior to Implementation of Compensatory Actions: The inspectors determined that the initial temperatures would have been higher than during the special test, because the injection valve was cycled and due to the piping being insulated. The inspectors noted that the system pressure could have been only slightly above ambient pressure, which would result in less of a pressure drop when the test return line was opened. However, because the temperatures were above saturation, a steam void would most likely exist prior to the start of the test and might expand, depending on the pressure drop, when the test return lines were opened. Because the licensee only had limited information about the system temperatures and pressures prior to the compensatory actions being taken, the inspectors could not compute a likely void size. However, the inspectors concluded that the voids could be relatively consistent between tests due to the insulated pipe and licensee operating procedures for maintaining CST levels.

- Injection Prior to Implementation of Compensatory Actions: In calculation MPR-2880, the licensee analyzed the potential for a steam void to form between the check valve and the injection valve. The licensee determined that as the injection valve opened, water between the check valve and injection valve would flow back and collapse the initial void, while a second void would form between the two valves. This secondary void would collapse following collapse of the first void.

The inspectors disagreed with this conclusion as it did not account for the increased thermal energy of the water between the valves. The inspectors noted that the licensee's temperature measurements indicated that the temperature between the valves was approximately 100 degrees higher than upstream of the injection valve. Based on the thermodynamic properties of the water between the valves, the inspectors determined that approximately 15 percent of the fluid would flash to steam. While opening of the injection valve would increase the pressure in the HPCI system, thus raising the saturation temperature, the inspectors did not conclude that the pre-existing steam void would collapse. Rather, the increased fluid temperature would maintain the void. Furthermore, the inspectors noted that the presence of any compressible gas, such as might have been present prior to routine venting being established, could allow the steam void to expand.

Risk Evaluation Sensitivity Study

In August 2006 the licensee performed an informal sensitivity analysis and evaluated the impact of increasing the impact pressure pulse to 1100 psi. In order to accomplish this, the licensee increase the void size and the air accumulator size. The inspectors determined the final void size was 1.6 ft^3; however, the inspectors did not have any information about the final accumulator size. Using the larger impact pressure, but realistic seismic loadings, the licensee determined that the piping and supports remained within the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), Section III, Appendix F, allowable values. Based on those results, the inspectors determined that there was sufficient margin to ensure system operability, even given the inspectors concerns that the surveillance test did not envelope the injection scenario. This conclusion assumed that all supports were fully operational.

Impact of Damaged Support

In January 2007, the licensee identified that HPCI riser clamp support EBB-5-SR-9 was missing a bolt, spacer and nut. The licensee's initial determination was that the loads could not be shown to remain within operability limits without detailed analysis. The inspectors determined that, as part of the information provided in response to the questions asked in the November 22, 2005, meeting, the licensee had indicated that this support had also been found with a missing bolt in March 1977 and with a loose bolt in November 1983. According to the information provided by the licensee, the support was not inspected since November 1983. Therefore, the inspectors determined that the previous conclusions about the operability of the HPCI system, especially during an injection event, needed to be re-examined. Pending additional information from the licensee, this unresolved item remains open.

2. Failure to Identify Condition Adverse to Quality

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" having very low safety significance (Green). Specifically, the licensee failed to identify and correct a condition adverse to quality regarding a test pressure significantly over the HPCI system design pressure which was recorded in a vent line during a surveillance test on February 11, 2006, until prompted by the NRC.

Description: On February 11, 2006, during a specially-instrumented HPCI system surveillance test, the licensee attached a pressure gauge to the vent line just upstream of injection valve MO-2312. The pressure gauge recorded two large peaks between 1828 and 1940 psi above an unknown base pressure. Although these pressures, by themselves, were above the maximum design pressure, the licensee did not enter this condition adverse to quality into its corrective action system until two months later, after the NRC repeatedly questioned why the effects of the over pressure in the system had not been evaluated. On April 11, 2006, the licensee initiated CAP 41513 and on May 1, 2006, the licensee approved calculation MPR 0078-0503-08, "Investigation of Pressure Transient Measured at End of Vent Line." The inspectors noted that both the CAP evaluation and calculation were slightly non-conservative as they did not address the test report information about the pressures being pulses above the static or transient pressure present at the time and did not add in any static pressure. Based on informal calculations, the inspectors determined that the vent line piping would have met the acceptance limits specified in ASME, Section III, Appendix F.

Analysis: The inspectors determined that the failure to identify and correct a condition adverse to quality was a performance deficiency as required by 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions." Furthermore, the inspectors determined that it was reasonably within the licensee's control to have identified this issue when they reviewed the test results and issued the test report.

The inspectors determined the performance deficiency was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B "Issue Screening" because, the finding was associated with the Mitigating Systems cornerstone attributes of equipment performance and affected the associated cornerstone objective of ensuring the availability, reliability, and capability of the HPCI system, which responds to initiating events to prevent undesirable consequences. Specifically, the pressure pulse exceeded the design pressure rating of the piping. Without evaluation, the licensee could not ensure the availability and reliability of the over-pressurized vent piping during HPCI operation.

The inspectors evaluated the finding using IMC 0609, "Significance Determination Process," Appendix A, Phase 1 screening. The finding screened as Green because it was not a design issue, did not represent an actual loss of a system safety function, did not result in exceeding a Technical Specification allowed outage time, was not an actual loss of non-safety-related equipment and did not affect external event mitigation.

The inspectors determined that a contributing cause to the finding was related to the cross-cutting aspect of human performance because the licensee failed to use a systematic process when faced with an unexpected plant condition during a special test. Specifically, the peak pressure measured in the vent line during the test significantly exceeded the design pressure and the test control process failed to evaluate all measured pressures.

Enforcement: Title 10 of the CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that the licensee establish measures to ensure that conditions adverse to quality, such as failures; malfunctions; deficiencies; deviations; defective material and equipment; and non-conformances, are promptly identified and corrected, for those systems, structures and components covered under 10 CFR Part 50, Appendix B.

Contrary to the above, from February 11, 2006 to April 11, 2006, a condition adverse to quality was not identified by the licensee, and was not corrected. Specifically, on February 11, 2006, the licensee recorded pressures in a vent line on the HPCI system, a system covered under 10 CFR Part 50, Appendix B. Although the recorded pressures were above the design pressure for the system, resulting in a non-conformance with the design, the licensee did not enter the issue into its corrective action system, nor take any actions to correct the non-conformance until prompted by the NRC. On April 11, 2006, following NRC prompting, the licensee entered the issue into its corrective action program as CAP 41513.

Because the issue was determined to be of very low safety significance, and because the licensee subsequently entered the issue into its corrective action system, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000331/2006008-01).

3. Feedwater System Operability

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance (Green). Specifically, the licensee’s calculation to show that the existing feedwater piping system configuration met the acceptance criteria of ASME BPVC, Section III, Appendix F used a method of analysis that did not evaluate the dynamic effect of impact forces as specified by the design basis piping code, American National Standards Institute (ANSI) B31.1, “Power Piping.”

Description: During review of the licensee’s operability evaluation resulting from the HPCI steam void issue, calculation DAEC-15Q-301, the inspectors identified a potential non-conservative method of analysis. Specifically, where computer analysis of the feedwater piping system calculated pipe deflection during a seismic event that exceeded travel limits for the spring component (i.e., the spring bottomed out which would restrain further pipe deflection), the licensee increased the spring stiffness to limit the pipe seismic deflection to the available hanger travel. In effect, the analytical model of the feedwater system was modified as though there were flexible struts installed when, in actuality flexible struts were not installed. Although this modified feedwater system analytical model resulted in a seismic load increase at the spring hanger locations, the inspectors questioned the licensee as to the acceptability of the approach since the method did not consider the transient effect of impact, as specified in the feedwater system’s ANSI B31.1 design basis code, where additional reaction force would be generated as a result of rapid pipe deceleration when the spring hanger bottomed out. The inspectors noted that the licensee’s initial calculations showed loads that were above the design allowable. Therefore, the inspectors deemed that the non-conservatisms could affect operability of the system.

The licensee subsequently used a different method of analysis that considered the dynamic effect of impact between the feedwater piping and the variable spring hangers that exceeded available seismic travel. This evaluation, documented in calculation 06Q3602-01, demonstrated that the variable spring hangers determined to exceed available seismic travel met ASME Section III, Appendix F acceptance limits thereby demonstrating the functional capability of the feedwater system.

The licensee entered this issue into their corrective action program as CAP041622.

Analysis The inspectors determined that a performance deficiency existed because the licensee failed to evaluate the dynamic effect of impact when variable spring hangers were determined to exceed their available seismic travel as required by the design basis ANSI B31.1 piping code. Furthermore, the inspectors determined that it was reasonably within the licensee's control to have identified this ANSI B31.1 design basis code requirement.

The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," because it affected the Mitigating Systems Cornerstone attribute of design control, and if left uncorrected, the finding could become a more significant safety concern. Specifically, the failure to evaluate the dynamic effect of impact as required by the ANSI B31.1 design basis code in similar operability calculations could result in exceeding the ASME Section III, Appendix F acceptance limits used to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The finding screened as having very low safety significance (Green) using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," because the inspectors answered "no" to question 1 under the Mitigating Systems Cornerstone column of the Phase 1 worksheet. Specifically, since the licensee subsequently evaluated the spring hanger supports that exceeded their available seismic travel for the dynamic effect of impact and determined that these hangers met ASME Section III, Appendix F acceptance limits, the finding was a design or qualification deficiency confirmed not to result in a loss of operability per "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment." Based on this Phase 1 screening, the inspectors concluded that the issue was of very low safety significance (Green).

The inspectors also determined that a primary cause of this finding was related to the cross-cutting area of human performance because the licensee did not have adequate guidance on how to evaluate the dynamic effect of impact for variable spring hanger determined to exceed their available seismic travel.

Enforcement: Title 10 of the CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that applicable regulatory requirements and the design basis be correctly translated into specifications, drawings, procedures and instructions, for those systems, structures and components covered under 10 CFR Part 50, Appendix B.

Contrary to the above, on April 13, 2006, the inspectors identified that licensee calculation DAEC-15Q-301 failed to evaluate the dynamic effect of impact as specified by the feedwater piping system's ANSI B31.1 design basis code. Because this issue was of very low safety significance, and because it was entered in the licensee's corrective action program as CAP041622, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000331/2006008-02)

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. G. Van Middlesworth and other members of licensee management on February 12, 2007. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
G. Van Middlesworth, Site Vice President
J. Bjorseth, Site Director
D. Curtland, Plant Manager
S. Catron, Licensing Manager
S. Haller, Site Engineering Director
R. Murrell, NRC Contact
L. Bruster, Juno Beach Engineering

Nuclear Regulatory Commission
A.M. Stone, Chief, Engineering Branch 2, Division of Reactor Safety
B. Burgess, Chief, Reactor Projects Branch 2, Division of Reactor Projects
R. Orlikowski, Senior Resident Inspector
R. Baker, Resident Inspector
S. Sheldon, Reactor Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000331/2006008-01	NCV	Recorded Pressure above Design Limits Not Entered into Corrective Action System
05000331/2006008-02	NCV	Non-conservative Analysis Methodology

Closed

05000331/2006008-01	NCV	Recorded Pressure above Design Limits Not Entered into Corrective Action System
05000331/2006008-02	NCV	Non-conservative Analysis Methodology

Discussed

05000331/2006002-03	URI	Potential Inoperability of the High Pressure Coolant Injection Pump

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Furthermore, inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Calculations

- 0078-0503-01; Volume of Potential Steam Bubble Upstream of HPCI Injection Mov; Revision 2
- 0078-0503-02; HPCI System Transient Thermal Hydraulic Analysis; Revision 2
- 0078-0503-03; HPCI System Transient Structural Analysis; Revision 3
- 0078-0503-04; Pipe Support Evaluation; Revision 1
- 0078-0503-05; Structural Analysis of Anchor EBB-5-SA-5; Revision 1
- 0078-0503-06; HPCI System Transient Structural Analysis; Revision 2
- 0078-0503-08; Investigation of Pressure Transient Measured at End of Vent Line; Revision 0
- 06Q3602-01; Operability Evaluation of the Feedwater Piping System Spring Cans That Exceed Their Design Range during a Design Basis Earthquake (DBE); Revisions 0 and 1
- DAEC-15Q-301; Operability Evaluation of Feedwater Piping outside Drywell; Revision 4
- DAEC-16-301; Operability Analysis of Support Clamp; Revision 2
- M82-33; HPCI Flow Orifice FE-2309 Differential Pressure Versus Flow; dated February 2, 1983
- MPR-2880; Duane Arnold Evaluation of HPCI Piping Voiding; Revision 0
- S-11981-002-001; Determination of Critical Capacities for Pipe Supports; Revision 0
- Unnumbered; Evaluation of Supports and 1E-6A&B Outlet Nozzles for Operability Loading; Revision 1

Corrective Action Process Documents

- 030715; Re-evaluate OE 16542 Evaluation – Venting HPCI Discharge Piping; dated February 13, 2004
- 038124; Unplanned HPCI Inoperability; dated September 29, 2005
- 038155; HPCI Discharge Pipe EBB005 Maximum Service Temperature Exceeded; dated October 2, 2005
- 040466; HPCI Discharge Piping Temperature High out of Specification per High Value in Operator’s Log; dated February 17, 2006
- 040653; HPCI Suction Pressure Is Elevated Following Discharge Piping Venting; dated February 28, 2006
- 040744; Pipe Clamp in Bill of Materials Not Compatible with Load on Design Drawing; dated March 6, 2006
- 040757; HPCI Discharge Temperatures High out of Specification; dated March 7, 2006
- 040757; HPCI Discharge Temperatures High out of Specification; dated March 7, 2006
- 041015; Feedwater Piping Design Calculation Discrepancies; dated March 17, 2006

- 041109; Deficiencies Found in HPCI Pump Discharge Piping Calculation Cal-080-612<3>; dated March 22, 2006
- 041122; As-built Plant Configuration Different from That Assumed in HPCI Voiding; dated March 23, 2006
- 046624; Missing Bolt at HPCI Injection Line Pipe Support EBB-5-SR-9; dated January 24, 2007

Corrective Action Process Documents Written as a Result of the Inspection

- 041513; HPCI Vent Line Pressure Pulse; dated April 11, 2006
- 041622; Additional Analysis Requested for Feedwater Spring Cans; dated April 17, 2006

Condition Evaluations

- 003046; HPCI Discharge Pipe EBB005 Maximum Service Temperature Exceeded (Including Engineering Evaluation); dated October 10, 2005
- 003049; Document Change in Operability Status for the HPCI System (Including Operability Evaluation); dated October 11, 2005

Drawings

- 7884-M117-20(3)-1; HPCI off Feedwater Inside Steam Valve Chamber; Revision B
- 7884-M117-20(3)-1; HPCI off Feedwater Inside Steam Valve Chamber; Revision B
- 7884-M44A-9; Condensate Storage Tank – 10" Reactor Building Return; Revision 4
- 7884-M44A-9; Condensate Storage Tank – 10" Reactor Building Return; Revision 4
- APED-E41-006<3>; HPCI System Relay Logic; Revision 26
- APED-E41-006<3>; HPCI System Relay Logic; Revision 26
- APED-E41-031; HPCI Pump Curve; Revision 0
- APED-E41-031; HPCI Pump Curve; Revision 0
- APED-E41-3087-04; 12" – 600# Ans Orifice Flange; Revision 0
- APED-E41-3087-04; 12" – 600# Ans Orifice Flange; Revision 0
- BECH-E121<021>; Reactor Core Cooling Systems – HPCI Min Flow Valve; Revision 12
- BECH-E121<021>; Reactor Core Cooling Systems – HPCI Min Flow Valve; Revision 12
- BECH-M123; HPCI Water Side, Sheet 2; Revision 40
- BECH-M123; HPCI Water Side, Sheet 2; Revision 40
- BECH-M404-12; Condensate Storage Tank Levels; Revision 1
- BECH-M404-12; Condensate Storage Tank Levels; Revision 1
- BECH-M404-76; Suppression Chamber (Torus) Levels; Revision 15
- BECH-M404-76; Suppression Chamber (Torus) Levels; Revision 15
- ISO-DLA-001-01N; Isometric Turbine Building Feedwater System; Revision 5
- ISO-DLA-001-01N; Isometric Turbine Building Feedwater System; Revision 2
- ISO-DLA-001-01N; Isometric Turbine Building Feedwater System; Revision 2
- ISO-DLA-001-01N; Isometric Turbine Building Feedwater System; Revision 5
- ISO-EBB-005-01; Isometric HPCI Pump Discharge; Revision 0
- ISO-EBB-005-01; Isometric HPCI Pump Discharge; Revision 0
- ISO-EBB-006-01; HPCI Minimum Flow Line; Revision 1
- ISO-EBB-006-01; HPCI Minimum Flow Line; Revision 1

- ISO-EBB-007-01; Isometric HPCI Pump Discharge; Revision 2
- ISO-EBB-007-01; Isometric HPCI Pump Discharge; Revision 2
- ISO-FSK-04813; Steam Tunnel Area 4 & 5 Test Vent Piping; Revision 3
- ISO-FSK-04813; Steam Tunnel Area 4 & 5 Test Vent Piping; Revision 3
- M152A-009<1>; Valve Mo-2312 900 Pound Gate Valve; Revision 12
- M152A-009<1>; Valve Mo-2312 900 Pound Gate Valve; Revision 12

Miscellaneous

- 004840; Commitment: Vent HPCI Pump Discharge Line; dated March 7, 2005
- 05-180; Operating Order: HPCI Discharge Pipe Venting; dated October 11, 2005
- M351; Measuring and Test Equipment – Temperature Indicator Surface Thermometer; dated May 16, 2006
- Chart of Inservice Test Data for Mo-2312 (12/02 – 08/05); dated April 11, 2006
- Convection Current in Upstream (High Pressure Side) Pipe; dated October 12, 2005
- HPCI Surveillance Test Observation; dated October 11, 2005
- Licensee Phase III SDP Input on HPCI Inoperability Due Presence of a Steam Void (LER 2005-004-00); Undated but Attached to Electronic Mail; dated December 20, 2006
- Responses to NRC Questions or Requests for Information from 11/22/05 Meeting; dated April 13, 2006
- System Response with Steam Void Adjacent to Mo-2312; dated October 12, 2005
- System Surveillance Test Strip Charts; January 27, 2000; October 11, 2005; dated December 9, 2005; and February 11, 2006
- Thermography from Mo-2312; undated
- Turbulent Penetration (Aka Corkscrew Convection) Phenomenon at Duane Arnold; dated October 14, 2005

Operability Reviews

- 000320; Pipe Clamp in Bill of Materials Not Compatible with Load on Design Drawing (Including Calculation); Revisions 0 & 1
- 000321; Feedwater and Attached Piping; Revisions 0 and 1
- 000323; Re-evaluation of HPCI Operability; Revision 0
- 003046; Evaluate HPCI Discharge Piping for an Assumed Temperature as High as 250°F; Revision 3

Procedures

- ACP 114.5; Action Request System; Revision 50
- ODI-013; Second Assistant's Log; Revision 24; February 12, 2006 and February 16, 2006
- OI 152; HPCI System; undated
- STP-3.5.1-05; HPCI System Operability Test; Revision 24
- STP-3.5.1-07; HPCI System Simulated Automatic Actuation; Revision 7
- STP-3.5.1-09; HPCI System Post-Startup Operability Test; Revision 9

Reports

- 001038; Root Cause Evaluation: Equipment Root Cause Analysis of Unplanned HPCI Limiting Condition for Operation – Venting; dated April 17, 2006
- HPCI Testing Report (Test Date) 2/11/06; dated February 20, 2006
- Infrared Thermograph Inspection Report; dated October 5, 2005

Work Orders

- A71759BS; Need to Collect Pressure and Vibration Data for HPCI Steam Voiding Analysis; dated February 6, 2006
- A71768AS; Install Temperature Monitoring Equipment and Collect Data to Support Analysis of the HPCI Steam Voiding Issue; dated January 25, 2006

LIST OF ACRONYMS USED

ADAMS	Agency-wide Document Access and Management System
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
BPVC	Boiler and Pressure Vessel Code
CAP	Corrective Action Program
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
IMC	Inspection Manual Chapter
IR	Inspection Report
HPCI	High Pressure Coolant Injection
LER	Licensee Event Report
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
psi	pounds per square inch
SDP	Significance Determination Process
URI	Unresolved Item