UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

November 14, 2013

EA-13-223

Mr. Richard L. Anderson
Vice President
NextEra Energy Duane Arnold, LLC
3277 DAEC Road
Palo, IA 52324-9785

SUBJECT: DUANE ARNOLD ENERGY CENTER – NRC INTEGRATED INSPECTION REPORT 05000331/2013004, PRELIMINARY WHITE FINDING

Dear Mr. Anderson:

On September 30, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Duane Arnold Energy Center. On November 12, 2013, the NRC inspectors discussed the results of this inspection with you and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

The enclosed inspection report discusses a finding that has preliminarily been determined to be a White finding with low to moderate safety significance that may require additional inspection, regulatory action, and oversight. As described in Section 1R15.1 of the enclosed report, the self-revealed finding involved the licensee's failure to perform an immediate operability determination in accordance with licensee procedures on June 21, 2013, when a Reactor Core Isolation Cooling (RCIC) system turbine speed indicator in the main control room was found degraded. Specifically, the licensee failed to consider the degraded speed indication indicative of a problem within the RCIC electronic governor module (EG-M) circuitry (failed voltage-dropping resistor) that resulted in the inoperability of RCIC. This was not discovered until August 22, 2013, when the RCIC turbine tripped on overspeed during startup for post-maintenance surveillance testing.

The finding is not a current safety concern. On August 24, 2013, actions were completed to replace the voltage-dropping resistor for the RCIC EG-M power supply, review extent of condition, and perform appropriate post-maintenance testing.

This finding was assessed based on the best available information, using the NRC's significance determination process (SDP). The basis for the NRC's preliminary significance determination is described in the enclosed report. The NRC will inform you in writing when the final significance has been determined.

The finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the Enforcement Policy, which appears on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

We intend to complete and issue our final safety significance determination within 90 days from the date of this letter. The NRC's SDP is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination.

Before the NRC makes a final decision on this matter, you may choose to (1) attend a regulatory conference, where you can present to the NRC your point of view on the facts and assumptions used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a regulatory conference, it should be held within 30 days of your receipt of this letter. We encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. The focus of the regulatory conference is to discuss the significance of the finding and not necessarily the root causes(s) or corrective action(s) associated with the finding. If you choose to attend a regulatory conference, it will be open for public observation. The NRC will issue a public meeting notice and press release to announce the conference. If you decide to submit only a written response, it should be sent to the NRC within 30 days of this letter. If you choose not to request a regulatory conference or to submit a written response, you will not be allowed to appeal the NRC's final significance determination.

Please contact Ms. Christine Lipa at (630) 829-9703, and in writing, within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision.

Because the NRC has not made a final determination in this matter, no notice of violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation may change based on further NRC review.

This report also documents two NRC-identified findings of very low safety significance (Green). The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your Corrective Action Program (CAP), the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the violations or significance of these NCVs, 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 copies to the Regional Administrator, Region III; the Director, Office of Enforcement, U.S Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspector at Duane Arnold Energy Center. In addition, if you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III; and the NRC resident inspector at Duane Arnold Energy Center.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth G. O'Brien, Acting Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000331/2013004
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ™

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-331
License No:	DPR-49
Report No:	05000331/2013004
Licensee:	NextEra Energy Duane Arnold, LLC
Facility:	Duane Arnold Energy Center
Location:	Palo, IA
Dates:	July 1 through September 30, 2013
Inspectors:	L. Haeg, Senior Resident Inspector R. Murray, Resident Inspector A. Shaikh, Inspector, DRS V. Myers, Health Physicist, DRS
Approved by:	Christine Lipa, Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000331/2013004, 07/01/2013 – 09/30/2013; Duane Arnold Energy Center; Maintenance Effectiveness, and Operability Determinations and Functionality Assessments.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. One self-revealed finding, preliminarily determined to be White, or a finding of low to moderate safety significance and two Green findings of very low safety significance were identified by the inspectors. The preliminary White finding is associated with an apparent violation of NRC requirements. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using IMC 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross Cutting Areas" dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

Green. A finding of very low safety significance and associated non-citied violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to accomplish safety-related procedure EN-AA-203-1001, "Operability Determinations/Functionality Assessments." Specifically, during the Fall 2012 refueling outage, the licensee failed to evaluate the extent of condition under a prompt operability determination (POD) for the 'A' residual heat removal service water (RHRSW) subsystem after identifying several locations of the 'B' RHRSW supply piping that was less than the minimum acceptable wall thickness. By not performing a POD, the operations shift manager (OSM) was not able to perform his or her responsibility to review, assess, and approve the operability call regarding the potential for wall thinning of the 'A' RHRSW piping. The licensee entered the inspectors' concerns into the CAP as Condition Report (CR) 01892263. The licensee completed a POD to evaluate the extent of wall thinning condition for the 'A' RHRSW subsystem and determined that the 'A' RHRSW subsystem was operable but with reduced margin to design specifications. This was reviewed and approved by the OSM. The inspectors determined that the issue of concern represented a performance deficiency because it was the result of the licensee's failure to meet a procedural requirement, and the cause was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor and a finding because if left uncorrected, failing to properly assess the impact of extent of condition for operability on similar structures, systems, or components (SSCs) would have the potential to lead to a more significant safety concern. The inspectors applied IMC 0609, Attachment 4, "Initial Characterization of Findings," to this finding. Because the finding pertained to operations while the plant was both shutdown and operating, the inspectors referenced both IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," and IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power."

Per IMC 0609, Appendix G, the inspectors determined that the finding did not require a quantitative assessment and therefore screened as very low safety significance (Green). Additionally, per IMC 0609, Appendix A, the inspectors determined that although the finding was a deficiency affecting the design and qualification of the SSC, the SSC maintained its operability and therefore also screened as very low safety significance (Green).

The inspectors determined that the performance characteristic of the finding that was the most significant causal factor of the performance deficiency was associated with the cross-cutting aspect of Human Performance, having Decision Making components, and involving the licensee making safety or risk-significant decisions using a systematic process, especially when faced with uncertain or unexpected plant conditions, to ensure safety is maintained. Further, this includes formally defining the authority and roles for decisions affecting nuclear safety, and implementing these roles and authorities as designed. Specifically, the evaluation of extent of condition for the identified pipe wall thinning of the 'B' RHRSW subsystem was not performed under the systematic operability determination process which resulted in bypassing the OSM's role in assessing and approving operability following the identification of a degraded or non-conforming condition. [H.1(a)] (Section 1R12.1)

- Preliminary White. A finding and apparent violation of Technical Specification (TS) Limiting Condition for Operation (LCO) 3.5.3, Condition B was self-revealed for the licensee's failure to perform an immediate operability determination (IOD) in accordance with licensee procedures on June 21, 2013, when a RCIC system turbine speed indicator in the main control room was found degraded. Specifically, the licensee failed to consider the degraded speed indication indicative of a problem within the RCIC EG-M circuitry (failed voltage-dropping resistor) that resulted in the inoperability of RCIC on August 22, 2013, when the RCIC turbine tripped on overspeed during post-maintenance surveillance testing. The licensee documented the issue in CR 01898931. Corrective actions included the replacement of the voltage-dropping resistor for the RCIC EG-M power supply, a review of extent of condition, and performing appropriate post-maintenance testing.

  The inspectors determined that the licensee's failure to perform an immediate operability determination in accordance with licensee procedures on June 21, 2013, when a RCIC system turbine speed indicator in the main control room was found degraded was a performance deficiency, because it was the result of the failure to meet a procedure requirement, and the cause was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor and a finding because it impacted the Mitigating Systems Cornerstone attribute of equipment performance and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency resulted in the inoperability of the RCIC system from June 21 through August 24, 2013.

  The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2 for the Mitigating Systems Cornerstone. The inspectors answered "Yes" to the screening question under the Mitigating Systems Cornerstone "Does the finding represent an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time

OR two separate safety systems out-of-service for > its Tech Spec Allowed Outage Time?," since the finding represented an actual loss of a safety function of a single train (RCIC) for 64 days, which is greater than the TS allowed outage time of 14 days. Therefore, a detailed risk evaluation was performed using IMC 0609, Appendix A. A Significance and Enforcement Review Panel (SERP) preliminarily determined this finding to have low to moderate safety significance (White).

The inspectors determined that the performance characteristic of the finding that was the most significant causal factor of the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, having Corrective Action Program components, and involving the licensee thoroughly evaluating problems such that the resolutions address causes and extent of conditions, as necessary. This includes properly classifying, prioritizing and evaluating for operability and reportability conditions adverse to quality. Specifically, the licensee did not fully evaluate the impact of the degraded RCIC turbine speed indicator on the operability of the RCIC system. The failure to fully evaluate and take corrective actions resulted in the RCIC system being in an inoperable condition for approximately 64 days. [P.1(c)] (Section 1R15.1)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to prescribe a procedure with appropriate qualitative acceptance criteria to ensure that CHANNEL CHECKs were satisfactorily accomplished in accordance with TS Surveillance Requirement (SR) 3.3.6.2 prior to September 12, 2013. Specifically, Surveillance Test Procedure (STP) 3.0.0-01 did not perform a qualitative assessment of channel behavior, nor did it require comparisons to other channel indications measuring the same parameter. Had STP 3.0.0-01 contained appropriate acceptance criteria, the main steam line area temperature indicating switch (TIS)-4480 would have been considered inoperable based on trending prior to switch anomalies resulting in declaring TIS-4480 inoperable on June 22, 2013. The licensee documented the issue in CR 01903528, briefed operators on the requirement to perform qualitative checks of the applicable instruments, and initiated a procedure change to restore compliance of the STP to meet the requirements of SR 3.3.6.2.

  The inspectors determined the licensee's failure to prescribe an STP with appropriate acceptance criteria was a performance deficiency because it was the result of the failure to meet a regulatory requirement, and the cause was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor and a finding because it impacted the Barrier Integrity Cornerstone attribute of procedure quality and adversely affected the Cornerstone objective of providing reasonable assurance that physical design barriers (i.e., containment) protect the public from radionuclide releases caused by accidents and events. The inspectors applied IMC 0609, Appendix A, Exhibit 3 for the Barrier Integrity Cornerstone. Because the finding did not represent an actual open pathway in the physical integrity of the reactor containment or containment isolation system, the finding screened as very low safety significance (Green).

  The inspectors determined that the performance characteristic of the finding that was the most significant causal factor of the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, having Corrective Action

Program components, and involving the licensee periodically trending and assessing information from the CAP in aggregate to identify programmatic problems. Specifically, there was sufficient information in the CAP that indicated the instruments may have been inoperable in the past, and those previous indications of inoperability were not identified by licensee procedures. [P.1(b)] (Section 1R15.1)

REPORT DETAILS

Summary of Plant Status

Duane Arnold Energy Center (DAEC) operated at full power for the entire inspection period except for brief down-power maneuvers to accomplish rod pattern adjustments or to conduct planned surveillance testing activities, with the exception of:

- Reduction in power to 51 percent on September 6, 2013, to repair a leaking lubricating oil fitting associated with the 'B' Reactor Feedwater Pump (RFP). The reactor was returned to full power on September 8, 2013.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternate alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- coordination between the TSO and the plant during off-normal or emergency events;
- explanations for the events;
- estimates of when the offsite power system would be returned to a normal state; and
- notifications from the TSO to the plant when the offsite power system were returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;

- re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

This inspection constituted one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

.2 Readiness For Impending Adverse Weather Condition – Extreme Heat

a. Inspection Scope

The inspectors performed a detailed review of the licensee's procedures and preparations for operating the facility during an extended period of time when ambient outside temperatures were high and the ultimate heat sink was experiencing elevated temperatures. The inspectors focused on plant specific design features and implementation of the procedures for responding to or mitigating the effects of these conditions on the operation of the facility's River Water Supply system, Reactor Building heating, ventilation, and air conditioning system, and offsite and alternate AC power systems. Inspection activities included a review of the licensee's adverse weather procedures, daily monitoring of the off-normal environmental conditions, and that operator actions specified by plant specific procedures were appropriate to ensure operability of the facility's normal and emergency cooling systems. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- ‘A’ Residual Heat Removal (RHR) subsystem with ‘B’ Standby Diesel Generator (SBDG) and ‘B’ Control Building Chiller subsystem out-of-service (OOS) for planned maintenance;
- Electric Fire Pump with the Diesel Fire Pump OOS for planned maintenance; and
- ‘B’ Emergency Service Water (ESW) system with the ‘A’ ESW subsystem OOS for planned testing.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the Updated Final Safety Analysis Report (UFSAR), TS requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These inspections constituted three quarterly partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On September 24 and 25, 2013, the inspectors performed a complete system alignment inspection of the RHR system, with the ‘A’ SBDG OOS for its planned two-year maintenance overhaul, to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on the availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Area Fire Plan (AFP)-74; Switchyard;
- AFP-69, -70, -71, and -72; Main, Standby, Startup, and Auxiliary Transformers, respectively;
- AFP-17, -21, and -22; Turbine Heater Bay, North and Middle Turbine Op Deck, and South Turbine Op Deck, respectively;
- AFP-25; Cable Spreading Room;
- AFP-14; North Turbine Building Basement Reactor Feed Pump Area and Turbine Lube Oil Tank Area; and
- AFP-18 and -19; Turbine Building North Turbine Building Ground Floor and Tube Pulling Area El 757' 6", and Turbine Building South Turbine Building Ground Floor, respectively.

The inspectors reviewed these areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for OOS, degraded or non-functional fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected these fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted six routine resident inspector tour samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Torus Room.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of the 'A' SBDG heat exchangers to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. Documents reviewed are listed in the Attachment to this document.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On September 16, 17, and 24, 2013, the inspectors observed crews of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas of the crew:

- licensed operator performance;
- clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one resident inspector quarterly review of licensed operator requalification sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On September 7, 2013, the inspectors observed operators in the control room during a planned downpower for a scheduled control rod pattern adjustment and maintenance to repair a lubricating oil leak on the 'B' RFP. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas of the crew:

- licensed operator performance;
- clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of procedures;

- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one resident inspector quarterly observation of heightened activity or risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- RHRSW system; and
- ESW system.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for SSCs/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These inspections constituted two routine quarterly evaluation samples as defined in IP 71111.12-05.

b. Findings

(1) Extent of Condition Not Properly Evaluated

Introduction: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to accomplish safety-related procedure EN-AA-203-1001, "Operability Determinations/Functionality Assessments." Specifically, during the Fall 2012 refueling outage 23 (RFO 23), the licensee failed to evaluate the extent of condition under a POD for the 'A' RHRSW subsystem after identifying several locations of the 'B' RHRSW supply piping that was less than the minimum acceptable wall thickness. By not performing a POD, the OSM was not able to perform their responsibility to review, assess, and approve the operability call regarding the potential for wall thinning of the 'A' RHRSW piping.

Description: On October 19, 2012, during RFO 23, the licensee performed non-destructive examinations of a section of normally buried 'B' RHRSW supply piping. These exams were being conducted with the subsystem OOS as part of the station's Corrosion Monitoring Program Manual Part C: Service Water and Fire Protection Monitoring Program; Revision 11; which implemented, in part, Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment" commitments, and In-service Inspection requirements of American Society of Mechanical Engineers (ASME) Section XI. The licensee identified a one inch diameter flaw area of piping where the pipe wall thickness was 0.140" which was below the required minimum wall thickness of 0.237" (0.375" nominal). The licensee documented the exam results in CR 01815022 and an IOD was made, stating in part, "B RHRSW is operable, but degraded. A POD is being requested to support this IOD. An extent of condition evaluation should be performed to determine if similar piping degradation exists in other similar piping." Engineering performed a white paper to evaluate the extent of condition and determined that an additional 10' section of 'B' RHRSW piping would address the extent of condition. The white paper also recognized that a work order was scheduled to perform exams of the 'A' RHRSW piping in the spring of 2013, and that a review of past exam data for the 'A' RHRSW subsystem was satisfactory. After performing additional exams of the 'B' RHRSW piping, the licensee decided to replace several feet of piping encompassing the flaws identified. Based on this decision, the POD was cancelled on October 26, 2012, due to the licensee's conclusion that the degraded condition was eliminated prior to restoring the 'B' RHRSW subsystem to an operable status. The POD cancellation noted, in part, that, "since this inspection was being performed as part of the Service Water and Fire Protection Monitoring Program, the extent of condition inspections were established within the rules of the program."

In July of 2013, during the Phase II performance of Temporary Instruction (TI) 182, "Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping and Tanks," an NRC Region III inspector questioned the licensee's extent of condition evaluation for 'A' RHRSW. Based on the scope of TI 182, and the ongoing operational questions posed, the inspector turned the question over to the resident inspectors for follow-up. The resident inspectors reviewed the licensee's piping exam data, corrosion monitoring program, and condition reports related to the Region III inspector's question. The resident inspectors were concerned that the licensee had not properly implemented the procedure requirements of EN-AA-203-1001, "Operability Determinations/Functionality Assessments," Revision 9, to evaluate the extent of condition of the ‘A’ RHRSW subsystem piping. In particular, EN-AA-203-1001, Attachment 1, Section 1.0, “IOD Process,” required, in part, that “if the identified condition could similarly affect other SSCs (extent of condition),” “then a POD is required to support operability.” The inspectors were also concerned that not performing a POD in this case resulted in the OSM not being afforded the opportunity to review and approve the operability basis for the extent of condition concern. The licensee captured the inspectors’ concerns as CR 01892263, performed a POD to assess the extent of the ‘B’ RHRSW wall thinning condition on the ‘A’ RHRSW subsystem, and performed a condition evaluation to enhance the operability process to clearly state the requirements for extent of condition reviews. The POD determined that the ‘A’ RHRSW subsystem was operable but with reduced margin to design specifications, and was reviewed and approved by the OSM.

Analysis: The inspectors determined that failing to perform a POD to review the extent of condition for wall thinning of the ‘A’ RHRSW piping represented an issue of concern. The inspectors determined that the issue of concern represented a performance deficiency because it was the result of the licensee’s failure to meet a procedural requirement, and the cause was reasonably within the licensee’s ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor and a finding because if left uncorrected, failing to properly assess the impact of extent of condition for operability on similar SSCs would have the potential to lead to a more significant safety concern.

The inspectors applied IMC 0609, Attachment 4, “Initial Characterization of Findings,” to this finding. Because the finding pertained to operations while the plant was both shutdown and operating, the inspectors referenced IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process,” and IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power.” Per IMC 0609, Appendix G, the inspectors determined that the finding did not require a quantitative assessment and therefore, screened as very low safety significance (Green). Additionally, per IMC 0609, Appendix A, the inspectors determined that although the finding was a deficiency affecting the design and qualification of the SSC, the SSC maintained its operability and therefore also screened as very low safety significance (Green).

The inspectors determined that the performance characteristic of the finding that was the most significant causal factor of the performance deficiency was associated with the cross-cutting aspect of Human Performance, having Decision Making components, and involving the licensee making safety or risk-significant decisions using a systematic process, especially when faced with uncertain or unexpected plant conditions, to ensure safety is maintained. Further, this includes formally defining the authority and roles for decisions affecting nuclear safety, and implementing these roles and authorities as designed. Specifically, the evaluation of extent of condition for the identified pipe wall thinning of the ‘B’ RHRSW subsystem was not performed under the systematic operability determination process which resulted in bypassing the OSM’s role in assessing and approving operability following the identification of a degraded or non-conforming condition. [H.1(a)]

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures. The licensee established EN-AA-203-1001, “Operability Determinations/Functionality Assessments,” Revision 9, in part, as the safety-related implementing procedure for the “preparation and approval of IODs and PODs required for establishing the acceptability of continued operation of the plant with a SSC that is suspected to be degraded or non-conforming,” an activity affecting quality.

Contrary to the above, on October 26, 2012, the licensee failed to prepare and approve a POD in accordance with EN-AA-203-1001. Specifically, upon the identification of a condition (pipe wall thinning of ‘B’ RHRSW) that similarly affected other SSCs (‘A’ RHRSW extent-of-condition); a POD was not performed as required to assess operability of ‘A’ RHRSW.

Corrective actions included the performance of POD 01892263 to properly evaluate, document and approve the extent of wall thinning condition and operability of ‘A’ RHRSW; and actions to enhance the operability process for extent of condition reviews.

Because this violation was of very low safety significance and was entered into the licensee’s CAP as CR 01892263, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (**NCV 05000331/2013004-01, Extent of Condition Not Properly Evaluated**).

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Work Week 1331; Leading Edge Flow Monitor input issue and ‘B’ RFP lubricating oil leak;
- Work Week 1332; Standby Gas Treatment (SBGT), RHRSW, and RHR maintenance, Local Power Range Monitor (LPRM) issues, ‘B’ RFP oil leak;
- RCIC turbine overspeed trip and emergent work;
- Startup Transformer scheduled maintenance and hot weather alert;
- Scheduled downpower on September 6, 2013;
- Work Week 1327; emergent switchyard 345 kV breaker work; and
- Diesel Fire Pump troubleshooting.

These activities were selected based on their potential risk-significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Documents reviewed are listed in the Attachment to this report.

These inspections constituted seven maintenance risk assessment and emergent work control samples as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- LPRM calibration not performed properly due to ‘C’ Traversing In-core Probe (TIP) traces being inadvertently rejected;
- Battery corrosion and “lead flakes” identified on 1D4, 250 VDC Battery;
- TISs 4479 and 4480 past operability review;
- Drywell Equipment Drain Sump failure to automatically pump;
- Drywell Equipment Drain Sump level float sticking;
- RCIC turbine trip on overspeed during post maintenance surveillance test; and
- Cedar River/Ultimate Heat Sink operability during elevated river bed levels.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee’s evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

These inspections constituted seven operability evaluation samples as defined in IP 71111.15-05.

b. Findings

(1) Failure to Perform CHANNEL CHECKS

Introduction: The inspectors identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the licensee's failure to prescribe a procedure with appropriate qualitative acceptance criteria to ensure that CHANNEL CHECKs were satisfactorily accomplished in accordance with TS SR 3.3.6.2 prior to September 12, 2013. Specifically,
STP 3.0.0-01 did not perform a qualitative assessment of channel behavior, nor did it require comparisons to other channel indications measuring the same parameter. Had STP 3.0.0-01 contained appropriate acceptance criteria, the TIS-4480 would have been considered inoperable based on trending prior to switch anomalies resulting in declaring TIS-4480 inoperable on June 22, 2013.

Description: On June 22, 2013, the licensee declared TIS-4480, Main Steam Line (MSL) 'D' turbine building temperature indicating switch, inoperable based on erratic indication in temperature without corresponding temperature changes of the other MSL area TIS indications. A review of TIS trend data indicated that TIS-4480 temperatures showed signs of instrument drift dating back to early to mid-May, 2013. The inspectors reviewed licensee procedures for evaluating MSL area TISs. Licensee procedure STP 3.0.0-01, "Instrument Checks," Revision 132, accomplished in part, SR 3.3.6.1.2 (Perform a CHANNEL CHECK) for TIS-4480. On a daily basis as part of STP 3.0.0-01, non-licensed operators log the MSL area TIS indications and compare them to the acceptance criteria of greater than or equal to 70°F or less than or equal to 185°F. The procedure stated that if the indicated temperatures were found outside of the acceptance criteria to inform the Control Room Supervisor (CRS). Duane Arnold's Technical Specifications defines a CHANNEL CHECK as, "A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter." The inspectors were concerned that contrary to the TS definition of a CHANNEL CHECK, STP 3.0.0-01 did not perform a qualitative assessment of channel behavior, nor did it require comparison to other channel indications measuring the same parameter. Additionally, Section 4.9 of STP 3.0.0-01 stated, in part, for CHANNEL CHECKS, that "Although, when performing channel checks, it is preferential to perform quantitative instrument checks, conditions may not always support quantitative checks. There may be times when a qualitative channel check may need to be performed in lieu of the preferred quantitative check." This statement did not indicate which steps in the procedure performed channel checks, nor did it direct when a qualitative check would be required or how to perform the qualitative check.

The inspectors also noted that the Duane Arnold TS bases for SR 3.3.6.1.2 stated, "A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in of the channels or of something more serious.

A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION."

Although the other MSL area TISs did not measure exactly the same parameter, the TISs were in the same general area, have historically trended in a similar manner, and the relative magnitude of changes have been historically similar. Trend data for TIS-4480 from approximately May 10 to June 22, 2013, showed an obvious sign of instrument drift from the other channels that should have been identified by performing an appropriate CHANNEL CHECK as discussed in STP 3.0.0-01 and the TS bases for SR 3.3.6.1.2.

Further, OP-002, "Weekly Auxiliary Operator and Second Assistant Log Review and Status Board Verification," Revision 20 states, in part, that "The CRS/OSM should review the Second Assistant and Auxiliary Operator log trends on a weekly basis. The person conducting this review should look for trends that indicate degradation in a system or component being monitored as well as the instruments used to monitor the system." Although the licensee did not credit procedure OP-002 for performing CHANNEL CHECKs, the inspectors determined that a review of the auxiliary operator log trends also could have identified the drift of instrument TIS-4480.

The licensee also completed a Past Operability Review (POR) for TIS-4480 under CR 1884408 and determined that TIS 4480 was inoperable from May 5, 2010, until June 21, 2010. The inspector's plan to evaluate the licensee's POR under a baseline inspection during the fourth quarter of 2013. The inspectors determined that had STP 3.0.0-01 contained appropriate acceptance criteria, the MSL area TIS-4480 would have been considered inoperable based on trending prior to the erratic response on June 22, 2013, leading to the licensee ultimately declaring the TIS inoperable.

<u>Analysis</u>: The inspectors identified an issue of concern for the licensee's failure to implement a procedure with appropriate qualitative acceptance criteria to ensure that CHANNEL CHECKs (as defined by Technical Specifications) were satisfactorily accomplished in accordance with TS SR 3.3.6.2 prior to September 13, 2013. The inspectors determined the issue was a performance deficiency because it was the result of the failure to comply with a regulatory requirement, and the cause was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor and a finding because it impacted the Barrier Integrity Cornerstone attribute of procedure quality and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers (i.e. containment) protect the public from radionuclides releases caused by accidents and events. Specifically, the failure to identify that containment isolation switches are inoperable could cause the containment isolation system to be susceptible to a single failure and could prevent the fulfillment of a safety function (i.e. Group I Containment Isolation).

The inspectors applied IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process for Findings at Power," Exhibit 3 for the Barrier Integrity Cornerstone. The inspectors answered no to both questions under "Reactor Containment" and the finding screened as very low safety significance (Green).

The inspectors determined that the performance characteristic of the finding that was the most significant causal factor of the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, having Corrective Action

Program components, and involving the licensee periodically trending and assessing information from the CAP in aggregate to identify programmatic problems. Specifically, there was sufficient information in the CAP that indicated the TISs may have been inoperable in the past, and those previous indications of inoperability were not identified by licensee procedures. Inspectors determined that surveillance requirements for CHANNEL CHECKS should have identified the conditions. [P.1(b)]

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall include appropriate qualitative or quantitative acceptance criteria. The licensee prescribed STP 3.0.0-01, "Instrument Checks", Revision 132, as the implementing procedure to accomplish SR 3.3.6.1.2, to perform a CHANNEL CHECK for the turbine building main steam line area temperature indicating switches, an activity affecting quality.

Contrary to the above, prior to September 12, 2013, the licensee failed to prescribe a procedure with appropriate qualitative acceptance criteria for performing SR 3.3.6.1.2. Specifically, STP 3.0.0-01, failed to direct the qualitative assessment of channel behavior during operation and did not meet the TS definition of a CHANNEL CHECK. Corrective actions included entering the issue into the CAP, briefing operators on the requirement to perform qualitative checks of the applicable instruments, and initiation of a procedure change to restore compliance of the STP to meet the requirements of SR 3.3.6.2.

Because this violation was of very low safety significance and was entered into the licensee's CAP as CR 01903528, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000331/2013004-02; Failure to Perform CHANNEL CHECKs)**.

(2) RCIC Turbine Overspeed Trip

Introduction: A finding and apparent violation of Technical Specification LCO 3.5.3, Condition B was self-revealed for the licensee's failure to perform an IOD in accordance with licensee procedures on June 21, 2013, when a RCIC system turbine speed indicator in the main control room was found degraded. Specifically, the licensee failed to consider the degraded speed indication indicative of a problem within the RCIC EG-M circuitry (failed voltage-dropping resistor) that resulted in the inoperability of RCIC on August 22, 2013, when the RCIC turbine tripped during post-maintenance surveillance testing. The licensee documented the issue in CR 01898931. Corrective actions included the replacement of the voltage-dropping resistor for the RCIC EG-M power supply, a review of extent of condition, and declaring the RCIC system operable following post maintenance testing.

Description: On June 21, 2013, an operator in the main control room noted that the RCIC turbine speed indicator was indicating 1200 revolutions per minute with the system in a standby readiness condition. The licensee documented this condition in CR 01884388. The operations shift manager reviewed this condition report but did not perform an IOD for RCIC based on the determination that the speed indicating meter was not classified as safety-related and did not perform any safety or TS function. Although the RCIC system is not considered a safety-related system at Duane Arnold, it is risk significant and important to safety. It also has a TS-defined function to remain Operable in Modes 1, 2, and 3 if reactor steam dome pressure is greater than 150 pounds per square inch gauge (psig). Duane Arnold classifies several components of the RCIC system as safety-related, and treats them as safety-related in their Quality Assurance program; however, the main control room RCIC turbine speed indicator was not one of these components. The licensee determined that the RCIC turbine speed indicator was a degraded instrument and closed the condition to a work request to be completed at a later date and did not further investigate the impact on the RCIC system.

On August 22, 2013, the licensee removed the RCIC system from service for planned maintenance, entered a 14-day TS LCO, and began troubleshooting of the RCIC turbine speed indicator. Instrumentation and Control technicians were unable to obtain the expected results during troubleshooting and the licensee decided to back out of the troubleshooting and rescheduled a repair for a later date in order to re-plan the activity. Quarterly surveillance testing of the RCIC system commenced in order to restore the RCIC to an operable status. When control room operators attempted to start the RCIC system per procedure by opening the steam supply valve, the RCIC turbine tripped on an overspeed condition via the electronic overspeed trip device. The operators secured the RCIC system and remained in the 14-day LCO to investigate the cause of the RCIC turbine trip.

During the investigation, the licensee identified that a voltage-dropping resistor from the 125 VDC electrical system to the RCIC EG-M (governor) power supply had failed. This had caused an incorrect voltage to be supplied to the RCIC EG-M, and in turn caused the turbine to overspeed upon startup. The licensee further identified that the EG-M governor failure was also responsible for the faulty RCIC speed indication in the main control room discovered initially on June 21, 2013. Further review of the RCIC EG-M circuitry diagram confirmed that the speed indicator was connected to the EG-M circuitry and could be affected by changes in the RCIC EG-M controls. The overspeed trip of RCIC on August 22, 2013, revealed to the licensee that RCIC was therefore inoperable since June 21, 2013 (a total of 63 days). Because this period of inoperability was longer than the allowed outage time of TS 3.5.3, Condition A (14 days), an apparent violation of TS had occurred and the issue was potentially risk significant.

Licensee procedure EN-AA-203-1001, “Operability Determinations/ Functionality Assessments,” Attachment 1, “Operability, Functionality, and Reportability Screening,” states, in part, that “if the identified condition concerns a TS (structure, system, or component) SSC and may affect the current operability of the SSC to perform its required safety functions,” then the required action is to “perform an immediate operability determination for the TS SSC.” Although the speed indicator was not used for any TS-required functions of the RCIC system, the failure of the speed indicator was indicative of a condition with the RCIC EG-M that constituted an operability concern and an IOD was required per licensee procedures. Additionally, the licensee’s CAP initial screen team and management review committee reviews and categorization of CR 01884388 did not further question the potential operability impact on RCIC for the degraded turbine speed indicator.

The licensee performed a past operability review and confirmed that the EG-M power supply dropping resistor had indeed failed on June 21, 2013; manifesting itself in the degraded RCIC turbine speed indicator in the main control room. Therefore, the RCIC system was considered inoperable from June 21, 2013, through August 24, 2013; when the RCIC system was restored. The licensee was in the process of performing a root cause evaluation (RCE) at the end of the inspection period to evaluate the causal factors surrounding the failure to identify and evaluate the speed indicator impact on RCIC operability.

Analysis: The inspectors determined that the licensee's failure to perform an immediate operability determination in accordance with licensee procedures on June 21, 2013, when a RCIC system turbine speed indicator in the main control room was found degraded was a performance deficiency, because it was the result of the failure to meet a procedure requirement, and the cause was reasonably within the licensee's ability to foresee and correct and should have been prevented.

The performance deficiency was determined to be more than minor and a finding because it impacted the Mitigating Systems Cornerstone attribute of equipment performance and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency resulted in the inoperability of the RCIC system from June 21 through August 24, 2013.

The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2 for the Mitigating Systems Cornerstone. The inspectors answered "Yes" to the screening question under the Mitigating Systems Cornerstone "Does the finding represent an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time OR two separate safety systems out-of-service for > its Tech Spec Allowed Outage Time?," since the finding represented an actual loss of function of a single train (RCIC) for 64 days, which is greater than the TS allowed outage time of 14 days. Therefore, a detailed risk evaluation was performed using IMC 0609, Appendix A.

The Senior Reactor Analysts (SRAs) evaluated the finding using the Duane Arnold Standardized Plant Analysis Risk (SPAR) external event model version 8.25, and the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations version 8.0.9.0.

The Duane Arnold SPAR model was recently modified for the evaluation of a diesel generator failure (NRC Inspection Report 05000331/2013010). Specifically, credit for using the Technical Support Center diesel generator to extend battery life was modeled. This change was also incorporated into model version 8.25 used for this detailed risk evaluation.

To model the performance deficiency, the SRAs set the basic event RCI-TDP-FS, "RCIC Pump Fails to Start" to True. The exposure period was 64 days, which included the out of service repair time for the system. The total delta core damage frequency (CDF) for internal and external events was estimated to be 3.5E-6/yr, with internal events contributing 1.6E-6/yr and external events contributing 1.9E-6/yr.

For external events, the dominant sequences involved a fire in the control building essential switchgear room followed by the failure of high pressure injection, successful depressurization and use of low pressure systems, followed by failure of all decay heat removal, successful containment venting and failure of late injection.

For internal events, the dominant sequences involved a station blackout (SBO) event, failure of RCIC due to the performance deficiency, failure of high pressure coolant injection (HPCI) and the failure to recover offsite or onsite power.

A loss of main feedwater with failure of RCIC, HPCI and depressurization is also a contributing sequence.

The SRAs used IMC 0609 Appendix H, "Containment Integrity Significance Determination Process" to evaluate the potential risk contribution due to large early release frequency (LERF). Duane Arnold has a Mark I containment. For at-power SBO and transient sequences, Appendix H applies a 0.6 factor to the CDF result when the sequences involve the reactor coolant system (RCS) at high pressure. The SRAs applied the 0.6 factor to all of the high pressure sequences contributing to the CDF result and estimated a delta LERF of 1.1E-6/yr (Yellow). This was viewed as a bounding result. The SRAs concluded that the significance characterization of the finding should be based on the change in CDF, and not increased based on the bounding LERF result.

The licensee performed a risk evaluation and provided it to the NRC on October 8, 2013. The licensee concluded that the finding was of very low safety significance, with an estimated delta CDF of 3.0E-7/yr.

The licensee evaluation considers recovery of the RCIC function by either manually controlling RCIC speed from the control room with MO-2405, the RCIC turbine stop valve, or by implementing the Emergency Management Guideline and Severe Accident Management Procedure (SAMP) 703, "RCIC Operation Following Loss of Electric Power." The licensee assigned a 0.1 failure probability to these actions and applied it to the internal event delta CDF result. The licensee doubled the internal event delta CDF result to account for the external event risk contribution.

The SRAs reviewed the licensee evaluation of potential RCIC recovery actions. With respect to manually controlling RCIC speed with MO-2405, the SRAs found that no procedure directed use of the valve and the RCIC system in this manner. The RCIC turbine stop valve is normally in the full open position and closes when the turbine trips. Without procedure guidance for operating the system with the turbine stop valve controlling RCIC speed and under the extreme stress conditions that would exist associated with the dominant risk sequences of interest, these actions would not be a reliable approach to recovering a start failure of the RCIC system due to a governor malfunction.

Manual operation of RCIC using SAMP 703 was also reviewed. Manual operation of RCIC can be credited in the baseline NRC SPAR model if RCIC is initially successful to extend the time available for offsite or onsite power recovery; it is not credited as a generic recovery action for RCIC failure events. Therefore, credit for manual operation of RCIC without electric power does not change the risk evaluation for a performance deficiency that results in a RCIC start failure event with electric power available. Nonetheless, the SRAs reviewed the procedures associated with manual operation of RCIC in the context of the dominant sequences and evaluated the potential for RCIC start failure recovery using SAMP 703. Considering the influence of negative human reliability performance shaping factors such as time available for diagnosis, extreme stress, lack of experience with manual operation under accident conditions, and poor ergonomics, the SRAs determined that manual operation of RCIC would also not be a reliable strategy for recovering a RCIC start failure.

A sensitivity evaluation was performed to consider the potential impact of crediting recovery of the RCIC start failure for station blackout events only. For other initiating events that contribute to the risk of the finding, such as loss of main feedwater and internal fire events, the SRAs determined that operators would more likely pursue mitigating strategies such as depressurization and use of low pressure systems that are covered in the emergency operating procedures rather than recovery of the RCIC function using non-standard system alignments after initial failure. The overall risk assessment conclusion was not significantly changed by considering limited potential for recovery of RCIC in station blackout scenarios.

The result of the detailed risk evaluation was a finding of low to moderate safety significance (White) with a total estimated delta CDF of 3.5E-6/yr.

<u>Evaluation of Cross-Cutting Aspects</u>

The inspectors determined that the performance characteristic of the finding that was the most significant causal factor of the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, having Corrective Action Program components, and involving the licensee thoroughly evaluating problems such that the resolutions address causes and extent of conditions, as necessary. This includes properly classifying, prioritizing and evaluating for operability and reportability conditions adverse to quality. Specifically, the licensee did not fully evaluate the impact of the degraded RCIC turbine speed indicator on the operability of the RCIC system. The failure to fully evaluate and take corrective actions resulted in the RCIC system being in an inoperable condition for approximately 64 days. [P.1(c)]

<u>Enforcement</u>: Duane Arnold Technical Specification LCO 3.5.3 states, in part, "The RCIC System shall be Operable." Condition A of LCO 3.5.3, Required Action A.2, directs, in part, restoration of the RCIC system to an operable status within 14 days of discovery of an inoperable condition. Condition B of LCO 3.5.3, Required Action B.1, directs, in part, placing the reactor in Mode 3 within 12 hours of not completing the actions in Condition A. On June 21, 2013, the degraded speed indicator in the main control room provided indication that the RCIC system was inoperable. As of August 22, 2013, a period greater than 14 days, the licensee had not restored the RCIC system to operable status and had not placed the reactor in Mode 3. This is an apparent violation of Technical Specification LCO 3.5.3, Condition B. The licensee entered this issue into their corrective action program as CR 01898931. Corrective actions included the replacement of the voltage-dropping resistor for the RCIC EG-M power supply, a review of extent of condition, and declaring the RCIC system operable following post maintenance testing. The licensee is also performing a RCE to evaluate the causal factors surrounding the failure to identify and evaluate the speed indicator impact on RCIC operability. This issue is being characterized as an apparent violation (AV) in accordance with NRC's Enforcement Policy, and its final significance will be dispositioned in separate future correspondence
(AV 05000331/2013004-03; RCIC Turbine Overspeed Trip).

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following modification:

- Temporary Modification (TM) 13-004; In Support of Maintenance, Install Temporary Hoses between the Electric Fire Pump and Ring Header during Work on Isolation Valves V33-47, 48, and 49.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one plant modification sample as defined in IP 71111.18-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following post-maintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- 1K3, ‘A’ Control Building (CB)/SBGT Air Compressor testing following planned maintenance;
- HPCI testing following planned maintenance;
- SV 8103A; Containment Atmosphere Monitoring Drywell Sample Valve testing following corrective maintenance for failed containment isolation surveillance test;
- STP 3.5.1-01B; ‘B’ Core Spray System Operability Test, following planned maintenance;
- Diesel Fire Pump testing following planned maintenance; and
- ‘A’ SBDG testing following planned maintenance.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable):

the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against the TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

These inspections constituted six post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- STP 3.5.1-11; 'B' Low Pressure Coolant Injection (LPCI) System Operability Tests and Comprehensive Pump Test; Revision 11 (in-service test);
- STP 3.0.0-01; Instrument Checks, Revision 135 (RCS);
- STP 3.3.6.1-10; Reactor Lo Lo Water Level (ATWS-RPT/ARI Trip/ Reactor Water Cleanup (RWCU) Isolation) and Lo Lo Lo Water Level (Main Steam Line Isolation Trip) Channel Calibration; Revision 11 (Routine);
- STP 3.8.1-04B; 'B' SBDG Operability Test; Revision 21 (Routine); and
- STP 3.3.1.1-24; Local Power Range Monitor Calibration; Revision 18 (Routine).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the UFSAR, procedures, and applicable commitments;

- measuring and test the equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for in-service testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted three routine samples, one in-service testing sample, and one reactor coolant system leak detection surveillance testing inspection sample, as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

This inspection constituted one complete sample as defined in IP 71124.01-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed all licensee performance indicators for the Occupational Exposure Cornerstone for follow-up. The inspectors reviewed the results of Radiation Protection Program audits (e.g., licensee's quality assurance audits or other independent audits). The inspectors reviewed any reports of operational occurrences related to occupational radiation safety since the last inspection. The inspectors reviewed the results of the audit and operational report reviews to gain insights into overall licensee performance.

b. Findings

No findings were identified.

.2 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors determined whether there had been changes to plant operations since the last inspection that could have resulted in any significant new radiological hazards for onsite workers or members of the public. The inspectors evaluated whether the licensee assessed the potential impact of any changes and had implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed the last two radiological surveys from selected plant areas and evaluated whether the thoroughness and frequency of the surveys where appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements to verify conditions.

The inspectors selected the following radiologically risk-significant work activities that involved exposure to radiation:

- In-Vessel Surveillance Specimen Holder Removal;
- Boral Badger Testing with Neutron Source; and
- Access to Steam Areas at High Power.

For these work activities, the inspectors assessed whether the pre-work surveys performed were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the Radiological Survey Program to determine if hazards were properly identified, including the following:

- identification of hot particles;
- the presence of alpha emitters;
- the potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials (This evaluation may have included licensee planned entries into non-routinely entered areas subject to previous contamination from failed fuel.);
- the hazards associated with work activities that could suddenly and severely increase radiological conditions and that the licensee had established a means to inform workers of changes that could significantly impact their occupational dose; and
- severe radiation field dose gradients that could result in non-uniform exposures of the body.

The inspectors observed work in potential airborne areas and evaluated whether the air samples were representative of the breathing air zone. The inspectors evaluated whether continuous air monitors were located in areas with low background to minimize false alarms and were representative of actual work areas. The inspectors evaluated the licensee's program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

b. Findings

No findings were identified.

.3 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors selected various containers holding non-exempt licensed radioactive materials that could cause unplanned or inadvertent exposure of workers and assessed whether the containers were labeled and controlled in accordance with 10 CFR 20.1904, "Labeling Containers," or met the requirements of 10 CFR 20.1905(g), "Exemptions To Labeling Requirements."

The inspectors reviewed the following radiation work permits used to access high radiation areas and evaluated the specified work control instructions or control barriers:

- In-Vessel Surveillance Specimen Holder Removal;
- Boral Badger Testing with Neutron Source; and
- Access to Steam Areas at High Power.

For these radiation work permits, the inspectors assessed whether allowable stay times or permissible dose (including from the intake of radioactive material) for radiologically significant work under each radiation work permit were clearly identified. The inspectors evaluated whether electronic personal dosimeter alarm set-points were in conformance with survey indications and plant policy.

The inspectors reviewed selected occurrences where a worker's electronic personal dosimeter noticeably malfunctioned or alarmed. The inspectors evaluated whether workers responded appropriately to the off-normal condition. The inspectors assessed whether the issue was included in the CAP and dose evaluations were conducted as appropriate.

For work activities that could suddenly and severely increase radiological conditions, the inspectors assessed the licensee's means to inform workers of changes that could significantly impact their occupational dose.

b. Findings

No findings were identified.

.4 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitored potentially contaminated material leaving the radiological control area and inspected the methods used for control, survey, and release from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use and evaluated whether the work was performed in accordance with plant procedures and whether the procedures were sufficient to control the spread of contamination and prevent unintended release of radioactive materials from the site. The inspectors assessed whether the radiation monitoring instrumentation had appropriate sensitivity for the type(s) of radiation present.

The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicated the presence of licensed radioactive material.

The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters. The inspectors assessed whether or not the licensee had established a de facto "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high-radiation background area.

The inspectors selected several sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact.

The inspectors evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

b. Findings

No findings were identified.

.5 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels) during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, radiation work permits, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls. The inspectors evaluated the licensee's use of electronic personal dosimeters in high noise areas as high radiation area monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee properly employed an NRC-approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high-radiation work areas with significant dose rate gradients.

As available, the inspectors reviewed radiation work permits for work within airborne radioactivity areas with the potential for individual worker internal exposures.

For these radiation work permits, the inspectors evaluated airborne radioactive controls and monitoring, including potential for significant airborne levels (e.g., grinding, grit blasting, system breaches, entry into tanks, cubicles, and reactor cavities). The inspectors assessed barrier (e.g., tent or glove box) integrity and temporary high-efficiency particulate air ventilation system operation.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within spent fuel and other storage pools. The inspectors assessed whether appropriate controls (i.e., administrative and physical controls) were in place to preclude inadvertent removal of these materials from the pool.

The inspectors examined the posting and physical controls for selected high radiation areas and very high radiation areas to verify conformance with the occupational performance indicator.

b. <u>Findings</u>

No findings were identified.

.6 <u>Risk-Significant High Radiation Area and Very High Radiation Area Controls</u> (02.06)

a. <u>Inspection Scope</u>

The inspectors discussed with the radiation protection manager the controls and procedures for high-risk high radiation areas and very high radiation areas. The inspectors discussed methods employed by the licensee to provide stricter control of very high radiation area access as specified in 10 CFR 20.1602, "Control of Access to Very High Radiation Areas," and Regulatory Guide 8.38, "Control of Access to High and Very High Radiation Areas of Nuclear Plants." The inspectors assessed whether any changes to licensee procedures substantially reduced the effectiveness and level of worker protection.

The inspectors discussed the controls in place for special areas that had the potential to become very high radiation areas during certain plant operations with first-line health physics supervisors (or equivalent positions having backshift health physics oversight authority). The inspectors assessed whether these plant operations required communication beforehand with the health physics group, so as to allow corresponding timely actions to properly post, control, and monitor the radiation hazards including re-access authorization.

The inspectors evaluated licensee controls for very high radiation areas and areas with the potential to become a very high radiation area to ensure that individuals were not able to gain unauthorized access to the very high radiation area.

b. Findings

No findings were identified.

.7 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance with respect to stated radiation protection work requirements. The inspectors assessed whether workers were aware of the radiological conditions in their workplace and the radiation work permit controls/limits in place, and whether their performance reflected the level of radiological hazards present.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed with the radiation protection manager any problems with the corrective actions planned or taken.

b. Findings

No findings were identified.

.8 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors observed the performance of the radiation protection technicians with respect to all radiation protection work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace and the radiation work permit controls/limits, and whether their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

b. Findings

No findings were identified.

.9 Problem Identification and Resolution (02.09)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring and exposure control were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring and exposure controls. The inspectors assessed the licensee's process for applying operating experience to their plant.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05)

This inspection constituted one complete sample as defined in IP 71124.05-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the plant UFSAR to identify radiation instruments associated with monitoring area radiological conditions including airborne radioactivity, process streams, effluents, materials/articles, and workers. Additionally, the inspectors reviewed the instrumentation and the associated TS requirements for post-accident monitoring instrumentation including instruments used for remote emergency assessment.

The inspectors reviewed a listing of in-service survey instrumentation including air samplers and small article monitors, along with instruments used to detect and analyze workers' external contamination. Additionally, the inspectors reviewed personnel contamination monitors and portal monitors, including whole body counters, to detect workers' internal contamination. The inspectors reviewed this list to assess whether an adequate number and type of instruments were available to support operations.

The inspectors reviewed licensee and third-party evaluation reports of the Radiation Monitoring Program since the last inspection. These reports were reviewed for insights into the licensee's program and to aid in selecting areas for review ("smart sampling").

The inspectors reviewed procedures that governed instrument source checks and calibrations, focusing on instruments used for monitoring transient high radiological conditions, including instruments used for underwater surveys. The inspectors reviewed the calibration and source check procedures for adequacy and as an aid to smart sampling.

The inspectors reviewed the area radiation monitor alarm setpoint values and setpoint bases as provided in the TSs and the UFSAR.

The inspectors reviewed effluent monitor alarm setpoint bases and the calculational methods provided in the Offsite Dose Calculation Manual (ODCM).

b. Findings

No findings were identified.

.2 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down effluent radiation monitoring systems, including at least one liquid and one airborne system. Focus was placed on flow measurement devices and all accessible point-of-discharge liquid and gaseous effluent monitors of the selected systems. The inspectors assessed whether the effluent/process monitor configurations aligned with ODCM descriptions and observed monitors for degradation and out-of-service tags.

The inspectors selected portable survey instruments that were in use or available for issuance and assessed calibration and source check stickers for currency as well as instrument material condition and operability.

The inspectors observed licensee staff performance as the staff demonstrated source checks for various types of portable survey instruments. The inspectors assessed whether high-range instruments were source checked on all appropriate scales.

The inspectors walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. Selectively, the inspectors compared monitor response (via local or remote control room indications) with actual area conditions for consistency.

The inspectors selected personnel contamination monitors, portal monitors, and small article monitors and evaluated whether the periodic source checks were performed in accordance with the manufacturer's recommendations and licensee procedures.

b. Findings

No findings were identified.

.3 Calibration and Testing Program (02.03)

Process and Effluent Monitors

a. Inspection Scope

The inspectors selected effluent monitor instruments (such as gaseous and liquid) and evaluated whether channel calibration and functional tests were performed consistent with radiological effluent Technical Specifications (RETS)/ODCM. The inspectors assessed whether: (a) the licensee calibrated its monitors with National Institute of Standards and Technology traceable sources; (b) the primary calibrations adequately represented the plant nuclide mix; (c) when secondary calibration sources were used, the sources were verified by the primary calibration; and (d) the licensee's channel calibrations encompassed the instrument's alarm set-points.

The inspectors assessed whether the effluent monitor alarm setpoints were established as provided in the ODCM and station procedures.

For changes to effluent monitor setpoints, the inspectors evaluated the basis for changes to ensure that an adequate justification existed.

b. Findings

No findings were identified.

Laboratory Instrumentation

a. Inspection Scope

The inspectors assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded instrument performance.

The inspectors assessed whether appropriate corrective actions were implemented in response to indications of degraded instrument performance.

b. Findings

No findings were identified.

Whole Body Counter

a. Inspection Scope

The inspectors reviewed the methods and sources used to perform whole body count functional checks before daily use of the instrument and assessed whether check sources were appropriate and aligned with the plant's isotopic mix.

The inspectors reviewed whole body count calibration records since the last inspection and evaluated whether calibration sources were representative of the plant source term and that appropriate calibration phantoms were used. The inspectors looked for anomalous results or other indications of instrument performance problems.

b. Findings

No findings were identified.

Post-Accident Monitoring Instrumentation

a. Inspection Scope

Inspectors selected containment high-range monitors and reviewed the calibration documentation since the last inspection.

The inspectors assessed whether electronic calibrations were completed for all range decades above 10 rem/hour and whether at least one decade at or below 10 rem/hour was calibrated using an appropriate radiation source.

The inspectors assessed whether calibration acceptance criteria were reasonable; accounting for the large measuring range and the intended purpose of the instruments.

The inspectors selected effluent/process monitors that were relied on by the licensee in its emergency operating procedures as a basis for triggering emergency action levels and subsequent emergency classifications, or to make protective action recommendations during an accident. The inspectors evaluated the calibration and availability of these instruments.

The inspectors reviewed the licensee's capability to collect high-range, post-accident iodine effluent samples.

As available, the inspectors observed electronic and radiation calibration of these instruments to assess conformity with the licensee's calibration and test protocols.

b. Findings

No findings were identified.

Portal Monitors, Personnel Contamination Monitors, and Small Article Monitors

a. Inspection Scope

For each type of these instruments used onsite, the inspectors assessed whether the alarm setpoint values were reasonable under the circumstances to ensure that licensed material was not released from the site.

The inspectors reviewed the calibration documentation for each instrument selected and discussed the calibration methods with the licensee to determine consistency with the manufacturer's recommendations.

b. Findings

No findings were identified.

Portable Survey Instruments, Area Radiation Monitors, Electronic Dosimetry, and Air Samplers/Continuous Air Monitors

a. Inspection Scope

The inspectors reviewed calibration documentation for at least one of each type of instrument. For portable survey instruments and area radiation monitors, the inspectors reviewed detector measurement geometry and calibration methods and had the licensee demonstrate use of its instrument calibrator as applicable. The inspectors conducted comparison of instrument readings versus an NRC survey instrument if problems were suspected.

As available, the inspectors selected portable survey instruments that did not meet acceptance criteria during calibration or source checks to assess whether the licensee had taken appropriate corrective action for instruments found significantly out of calibration (greater than 50 percent). The inspectors evaluated whether the licensee had evaluated the possible consequences of instrument use since the last successful calibration or source check.

b. Findings

No findings were identified.

Instrument Calibrator

a. Inspection Scope

As applicable, the inspectors reviewed the current output values for the licensee's portable survey and area radiation monitor instrument calibrator unit(s). The inspectors assessed whether the licensee periodically measures calibrator output over the range of the instruments used through measurements by ion chamber/electrometer.

The inspectors assessed whether the measuring devices were calibrated by a facility using National Institute of Standards and Technology traceable sources and whether corrective factors for these measuring devices were properly applied by the licensee in its output verification.

b. Findings

No findings were identified.

Calibration and Check Sources

a. Inspection Scope

The inspectors reviewed the licensee's 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," source term to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

b. Findings

No findings were identified.

.4 Problem Identification and Resolution (02.04)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring instrumentation.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency AC Power System performance indicator (PI) for the period from the third quarter of 2012 through the second quarter of 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports and NRC Integrated Inspection Reports for the period of July 2012 through June 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one MSPI emergency AC power system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - High Pressure Injection Systems performance indicator for the period from the third quarter of 2012 through the second quarter of 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of July 2012 through June 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one MSPI high pressure injection system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Heat Removal System performance indicator for the period from the third quarter of 2012 through the second quarter of 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of July 2012 through June 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one MSPI heat removal system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity PI for Duane Arnold Energy Center for the period from the fourth quarter 2012 through the second quarter 2013. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s reactor coolant system chemistry samples, TS requirements, issue reports, event reports, and NRC Integrated Inspection Reports to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems were identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one reactor coolant system specific activity sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.5 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the occupational radiological occurrences PI for the period from the fourth quarter 2012 through the second quarter 2013. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarms and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational exposure control effectiveness sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.6 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the RETS/ODCM radiological effluent occurrences PI for the period from the fourth quarter 2012 through the second quarter 2013. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's issue report database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one RETS/ODCM radiological effluent occurrences sample as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the operator workarounds (OWAs) on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment to this report were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This inspection constituted one operator workaround annual sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: TIS Issues

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized several corrective action items documenting issues with TISs. The inspectors' review indicated that the licensee had a plan for long term management of TIS issues, because they had been experiencing several failures over time. The inspectors identified a concern that the licensee was not recognizing TIS failures as they occurred, and there were questions regarding the past operability of some TISs. The inspectors reviewed instances of potential past operability concerns under IP 71111.15 and documented the results under section 1R15.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

No findings were identified.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 RCIC Turbine Trip During Testing

a. Inspection Scope

The inspectors reviewed the plant's response to the overspeed trip of the RCIC turbine on August 22, 2013, during test activities. Specifically, the inspectors reviewed the licensee's response to the condition, troubleshooting efforts, and corrective actions to replace a failed resistor and perform testing. The inspectors verified operability and reportability criteria were reviewed and appropriate; and also determined that the condition did not meet the criteria of a significant operational event per NRC Management Directive 8.3, "NRC Incident Investigation Program." The inspectors' review of the cause and significance of this issue is further discussed in Section 1R15 of this inspection report. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report (LER) 05000331/2013-001-00: Emergency Diesel Generator Inoperability Results in Safety System Functional Failure

This event, which occurred on March 8, 2013, was associated with the failure of the 'A' SBDG lube oil heat exchanger gasket during a maintenance run. This event was the subject of unresolved item (URI) 05000331/2013002-01 and was closed as a preliminary White finding and apparent violation in NRC IR 05000331/2013010. The inspectors' characterizations of the issue, as well as the licensee's corrective actions, are discussed in the aforementioned Inspection Reports. The inspectors reviewed the bases for the 10 CFR 50.73 LER and did not have any concerns with the scope or content of the report. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

4OA5 Other Activities

.1 Temporary Instruction (TI) - 2515/182 - Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks

a. Inspection Scope

Leakage from buried and underground pipes has resulted in ground water contamination incidents with associated heightened NRC and public interest. The industry issued a guidance document, NEI 09-14, "Guideline for the Management of Buried Piping Integrity" (ADAMS Accession No. ML1030901420) to describe the goals and required actions (commitments made by the licensee) resulting from this underground piping and tank initiative. On December 31, 2010, NEI issued Revision 1 to NEI 09-14, "Guidance for the Management of Underground Piping and Tank Integrity," (ADAMS Accession No. ML110700122), with an expanded scope of components which included underground piping that was not in direct contact with the soil and underground tanks. On November 17, 2011, the NRC issued TI-2515/182 "Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks" to gather information related to the industry's implementation of this initiative.

From July 22-26, 2013, the inspectors conducted a review of records and procedures related to the licensee's program for buried pipe, underground pipe, and tanks in accordance with Phase II of TI-2515/182. This review was performed to confirm that the licensee's program contained attributes consistent with Sections 3.3 A and 3.3 B of NEI 09-14 and to confirm that these attributes were scheduled and/or completed by the NEI 09-14 Revision 1 deadlines. The inspectors also conducted interviews with licensee staff responsible for the site's Buried Piping Program to determine whether the program attributes were implemented in a manner that reflected good or poor practices in program management.

Based upon the scope of the review described above, Phase II of TI-2515/182 was completed.

b. Observations

The licensee's Buried Piping And Underground Piping and Tanks Program was inspected in accordance with Paragraph 03.02.a of the TI and it was confirmed that activities which correspond to completion dates specified in the program which have passed since the Phase I inspection was conducted, have been completed. Additionally, the licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.b of the TI and responses to specific questions found in http://www.nrc.gov/reactors/operating/ops-experience/buried-pipe-ti-phase-2-insp-req-2011-11-16.pdf were submitted to the NRC headquarters staff.

c. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On November 12, 2013, the inspectors presented the inspection results to Mr. R. Anderson, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The Review of the Industry Initiative to control degradation of underground piping and tanks (TI -2515/182) with Mr. R. Anderson, Site Vice President and other members of the licensee staff on July 26, 2013; and

- The inspection results for the areas of radiological hazard assessment and exposure controls; radiation monitoring instrumentation; and RCS specific activity, occupational exposure control effectiveness, and RETS/ODCM radiological effluent occurrences performance indicator verification with Mr. R. Anderson, Site Vice President, on September 27, 2013.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Anderson, Site Vice President
G. Pry, Plant General Manager
K. Kleinheinz, Site Engineering Director
M. Davis, Licensing & Emergency Preparedness Manager
G. Young, Nuclear Oversight Manager
R. Wheaton, Operations Site Director
W. Bentley, Maintenance Site Director
R. Porter, Radiation Protection Manager
D. Olsen, Chemistry Manager
B. Kindred, Security Manager
C. Hill, Training Site Manager
B. Murrell, Licensing Engineer Analyst
L. Swenzinski, Licensing Engineer
J. Dubois, Program Engineering Manager
A. Thomas, Engineer Analyst, Buried Piping Program Owner
R. Frantz, Regulatory Assurance

Nuclear Regulatory Commission

C. Lipa, Chief, Reactor Projects Branch 1
C. Faria-Ocasio, Project Manager, NRR

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000331/2013004-01	NCV	Extent of Condition Not Properly Evaluated (RHRSW Piping) (Section 1R12.1)
05000331/2013004-02	NCV	Failure to Perform CHANNEL CHECKs (Section 1R15.1)
05000331/2013004-03	AV	RCIC Turbine Overspeed Trip (Section 1R15.2)

Closed

05000331/2013004-01	NCV	Extent of Condition Not Properly Evaluated (RHRSW Piping) (Section 1R12.1)
05000331/2013004-02	NCV	Failure to Perform CHANNEL CHECKs (Section 1R15.1)
05000331/2013-001-00	LER	Emergency Diesel Generator Inoperability Results in Safety System Functional Failure (Section 4OA3.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. 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.

1R01

OP-AA-102-1002 (DAEC); Seasonal Readiness; Revision 07
OP-AA-102-1002; Seasonal Readiness; Revision 01
Abnormal Operating Procedure (AOP) 903; Severe Weather; Revision 44
AOP 304; Grid Instability; Revision 35
Administrative Control Procedure (ACP) 101.16; MIDWEST ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/ Electric System Interfaces; Revision 07
ML060950462; St. Lucie, Units 1 and 2, Turkey Point, Units 3 and 4, Seabrook, Duane Arnold, NRC Generic Letter 2006/02 60-Day Response

1R04

OP-AA-102-1003; Guarded Equipment; Revision 03
OP-AA-102-1003 (DAEC); Guarded Equipment (DAEC Specific Information); Revision 27
Operating Instruction (OI) 149A1; RHR Electrical System Lineup; Revision 3
OI 149A2; ‘A’ RHR System Valve Lineup and Checklist; Revision 11
OI 149A4; ‘B’ RHR System Valve Lineup and Checklist; Revision 5
OI 149A6; RHR System Control Panel Lineup; Revision 2

1R05

ACP 1203.53; Fire Protection; Revision 18
ACP 1412.4; Impairments to Fire Protection Systems; Revision 67
DAEC Fire Plan – Volume 1, Program; Revision 66
AFP-74; Switchyard; Revision 5
AFP-69; Main Transformer 1X1; Revision 5
AFP-70; Standby Transformer 1X4; Revision 4
AFP-71; Startup Transformer 1X3; Revision 3
AFP-72; Auxiliary Transformer 1X2; Revision 3
AFP-14; Rx Feed Pump Area, Turbine Lube Oil Tank Area and 1A2 Switchgear Area, El. 734’; Revision 31
AFP-17; Condenser Bay, Heater Bay, & Steam Tunnel, EL 734' 0" and 757' 6"; Revision 26
AFP-18; North Turbine Building Ground Floor, Tube Pulling Area, & 1A1 Switchgear Room EL 757' 6"; Revision 30
AFP-19; South Turbine Building Ground Floor, EL 757' 6"; Revision 25
AFP-21; North Turbine Operating Floor & Middle Operating Floor EL 780' 0"; Revision 25
AFP-22; South Turbine Operating Floor & Demin Pits, EL 780' 0"; Revision 26
AFP-25; Cable Spreading Room, EL 772' 6"; Revision 26

1R06

AOP-902; Flood; Revision 48
ACP 109.5; Guidelines for Operability of Barriers; Revision 6
WO 1139360; Circ Pump Area to RHRSW Pump Area Door
WO 1141267; SE Corner Room Bottom Door
WO 1141266; SE Corner Room to Torus Door
WO 40172776; NW Corner Room to Torus Area Door and SE Corner Room to Torus Area Door

1R07

FPLE76-DAEC-1-1; Final Inspection Report; EDG-1E053A; Bundles A-1, A-2, A-3; September 2013

1R13

Work Planning Guideline-1; Work Process Guideline; Revision 59
Work Planning Guideline-2; Online Risk Management Guideline; Revision 63
OP-AA-104-1007; Online Aggregate Risk; Revision 02
WM-AA-1000; Work Activity Risk Management; Revision 14
WM-AA-100-1000; Work Activity Risk Management; Revision 0
OP-AA-102-1003; Guarded Equipment; Revision 03
OP-AA-102-1003 (DAEC); Guarded Equipment (DAEC Specific Information); Revision 27
Work Week 1331 Work Activity Risk Management (WARM) Summary and Weekly Probabilistic Risk Analysis (PRA)
Work Week 1332 Work Activity Risk Management (WARM) Summary and Weekly Probabilistic Risk Analysis (PRA)
CR 01884388; RCIC Turbine Speed Indicator Reading 1200 RPM Shutdown
CR 01895048; Drop in Indicated Core Thermal Power AOP 255.2 Entry

1R15

EN-AA-203-1001; Operability Determinations/ Functionality Assessments; Revision 12
OP-AA-100-1000; Conduct of Operations; Revision 10
POD and CR 01900523; Lead Flakes Found on 1D4 Battery Cell Plate Separators
CR 01888736; 1D4 Cell 30 Shows Signs of Corrosion
CR 01896309; TIP Traces from C Machine Rejected During Aug 01 LPRM Cal
STP 3.3.1.1-24; Local Power Range Monitor Calibration; Revision 18
STP 3.4.1-01; APRM Gain Adjust Calibration; Revision 6
BECH-C475; Reactor Building Drywell Vessel Supports and Construction Sequence; Revision 4
CR 01903528; Adequacy of SR 3.3.6.1.2-1.f, TB Main Steam Line TIS
CR 01884408; TIS4480 MSL D TB Steam Temp, PCIS Channel B2 Temp Rise
STP 3.0.0-01; Instrument Checks; Revision 132
CR 01897232; PDA – DPO on TIS 4479 and 4480
CR 01888245; Issues Regarding TIS4479 and TIS4480

1R18

ACP 103.2; 10 CFR 50.59 Screening Process; Revision 42
FP-E-MOD-03; Temporary Modifications; Revision 10
Engineering Change 0279575; In Support of Maintenance, Install Temporary Hoses Between 1P48 Electric Fire Pump and Ring Header During Work on Isolation Valves V33-47, 48, and 49.

DAEC Fire Plan – Volume 1, Program; Revision 64
STP NS13B014; Fire Water Valve Lineup Check; Revision 15
CR 01904604; Question Regarding Functionality of Fire Distribution System
CR 01905021; Fire Plan LCO Not Recognized During Planned Work

1R19

ACP 1408.1; Work Order Task(s); Revision 183
WO 40065865; Calibrate PI-7336A, 1K3 Discharge Pressure
WO 40209320; PS7333A, Inst Air Comp 1K-3 Start/ Stop Press Switch
WO 40157550; PS7334A, High Pressure Stop/ Alarm Switch
WO 40198735; 74-K7301A: Replace Relay
WO 40198738; 94-K7333A: Replace Relay (TDR)
WO 40196794; STP 3.7.9-02-A CB/ SBGTS Instrument Air Functional Test
STP 3.7.9-02A; 'A' CB/SBGTS Instrument Air Compressor Functional Test and Check Valve Testing; Revision 4
RELAY-A109-01; Replacing Agastat Timing Relays, Section D; Revision 3
WO 40177684; HPCI Turbine L/O Cooler HX Line: (PRA & LCO) Disassembly & Inspect
STP 3.5.1-05; HPCI System Operability Test; Revision 61
CR 01891863; Valve Failed to Close During STP 3.6.1.3-11A
STP 3.6.1.1-11; Containment Isolation Valve Leak Tightness Test- Type C Penetrations – Sampling/ Monitoring Valves; Revision 7
STP 3.5.1-01B; B Core Spray System Operability Test; Revision 14
WO 40197097; V21-0012 Disassembly and Inspection
WO 40110135; 1A404 – Refurbish Breaker

1R22

STP 3.5.1-11B; 'B' LPCI System Operability Tests and Comprehensive Pump Tests; Revision 11
CR 01893852; Safety – Long Term Scaffold Control
STP 3.3.6.1-10; Reactor Lo Lo Water Level (ATWS-RPT/ARI Trip/RWCU Isolation) and Lo Lo Lo Water Level (Main Steam Line Isolation Trip) Channel Calibration; Revision 11
CR 01895406; NRC Observation Comment of STP 3.3.6.1-10
STP 3.8.1-04B; 'B' SBDG Operability Test; Revision 21

2RS1

CR 01815652; Worker Received an Unanticipated Rate Alarm
CR 01817966; Un-Anticipated Dose Rate Alarm C Demin Septa Job
CR 01818157; Failure to Label (6) Drums with Radiological Info
CR 01818175; Changing Radiological Conditions Create a High Rad Area
CR 01838349; Missed Semi-Annual Surveys for 2012
CR 01846870; Increased Neutron Dose Rates at the DW Hatch
CR 01866379; Posting/Rad Material Tag Issues with Two Sealands in Yard
CR 01877989; Radiological Safety Near Miss – Contam Barrier Removed
CR 01887555; Unposted RCA Found in Yard
CR 01894028; Hot Spot Found During Routine Survey in LHRA
Radiation Work Permit (RWP) 13-0022; In-Vessel Surveillance Specimen Holder; Revision 00
RWP 13-0181; Boral Badger Testing with Neutron Source; Revision 00
RWP 13-0600; Steam Areas at High Power; Revision 00

HP-55; Radiological Work Screening Form; various dates
HP-21; HP Briefing Checklist Summary; various dates
RP-AA-104-1000-F02; Pre-Job ALARA Review; various dates
HP-41; Radiological Survey Maps; various dates
Health Physics Procedure (HPP) 3104.03; Radiological Air Sample Collection and Analysis; Revision 18
HPP 3103.03; Radiological Area Posting and Surveillances; Revision 58
RP-AA-104-1000; ALARA Implementing Procedure; Revision 5
HPP 3102.03; Radiation Protection Job Planning; Revision 37
WM-AA-1000; Work Activity Risk Management; Revision 13
HPP 3107.05; Release of Items from the RCA; Revision 18
ACP 1411.13; Control of Locked High Radiation Areas and Above; Revision 30
HPP 3104.10; Control of Drywell Access During Fuel Movement; Revision 8
ACP 1407.2; Material Control in the Spent Fuel Pool and Cask Pool; Revision 25

2RS5

CR 01677877; Delays in Restoration of FastScan Whole Body Counter
CR 01843182; Model 1000 Multi Source Gamma Calibrator Degradation
CR 01829345; M&TE HP1608 EAS as Found Data Was OOT
CR 01818041; M&TE HP1611 Air Sampler as Found Data Was OOT
CR 01782893; ThermoFisher Calibration Results Inadequate
CR 01890649; Unable to Meet ANSI N323B-2003
CR 01890425; Calibration Frequency for Portable RP Instruments Not Per ANSI N323B
CR 01878233; May’13 Monthly Not to be Performed Due to Out of Calibration
WO 01285831; MA Calibrate RE9178 Loop
WO 40193207; STP 3.45-03 Cal Of Primary Containment Air Sampling System
WO 40214533; STP NS790305 RHRSW Radiation Monitor Calibration
WO 40134978; STP 3.3.3.1-12 Pri Cont Area Rad Post Accident Mon Ins SRC
WO 40042475; MAPri Cont area Rad Post Accident Mon Ins Source Cal
HPP 3110.72 Appendix 2; Data Sheet 1 – Reference Standard and Calibration Confirmation Worksheet; various dates
HPP 3110.16 Attachment 1; SAM0-11 Calibration Form; November 1, 2012
Calibration Report RTM 950; May 1, 2013
HPP 3110.31 Attachment 1; Eberline PCM-1B Personnel Monitor Calibration Data Sheet; June 6, 2013
DAEC Metrology Lab Report of Calibration; Instrument HP1004; June 6, 2013
DAEC Metrology Lab Report of Calibration; Instrument HP1109; April 4, 2013
DAEC Metrology Lab Report of Calibration; Instrument HP1608; July 31, 2013
DAEC Metrology Lab Report of Calibration; Instrument HP3105; November 6, 2012
PASAP 2.0; Post-Accident Sampling System; Revision 4
HPP 3110.72; Calibration of the FastScan Whole Body Counter; Revision 2
HPP 3108.02; Inventory and Calibration Frequency for HP Instrumentation; Revision 15
HPP 3110.39; Calibration and Response Check of the Rados RTM 950 Portal Monitor; Revision 16
HPP 3110.31; Calibration of Eberline PCM-1B Personnel Monitor; Revision 11
HPP 3110.16; Calibration of the Thermo Eberline SAM-11 Monitor; Revision 4
PCP 8.7; Alarm Setpoints for Liquid Rad Monitors; various dates

4OA1

MSPI Basis Document; Revision 14
PCP 6.10; Reactor Coolant Iodine and Crud Activity; Revision 9
RCS Activity NRC PI Data Collection Package; Various Dates
RETS/ODCM Radiological Effluent NRC PI Data Collection Package; Various Dates
Occupational Exposure Control Effectiveness NRC PI Data Collection Package; Various Dates
MSPI Emergency AC Power System NRC PI Data Collection Package; 3rd Quarter 2012 Through 2nd Quarter 2013
MSPI High Pressure Injection System NRC PI Data Collection Package; 3rd Quarter 2012 Through 2nd Quarter 2013
MSPI Heat Removal System NRC PI Data Collection Package; 3rd Quarter 2012 Through 2nd Quarter 2013

4OA2

OA-AA-100-1002; Plant Status Control Management; Revision 0
PI-AA-101-1000; Human Performance Program Error Reduction Tools; Revision 9
ACP 1410.2; LCO Tracking and Safety Function Determination Program; Revision 31
ACP 1410.5; Plant Status Control Program; Revision 104
ACP 101.01; Procedure Use and Adherence; Revision 51
PI-AA-204; Condition Identification and Screening; Revision 52
PI-AA-100-1007; Apparent Cause Evaluation; Revision 7
CR 01903710; Past Leakage on MO-2135 Has Left a White Residue
CR 01903528; Adequacy of SR 3.3.6.1.2-1.f, TB Main Steam Line TIS
CR 01888137; TIS4445 Channel 1 Increasing Trend Toward Out of Spec
CR 01785218; Slow Rising Trend in Steam Tunnel Temperatures
CR 01835557; TIS 4479 Channel 1 Failed Channel Check Surveillance
CR 01834965; TIS4479 CH. 1 Indicating Above STP 3.0.0-01 Limit

4OA5

ER-AA-102; Buried Piping Program; Revision 3
Report No. 1000995; Duane Arnold energy Center Site Specific Risk Analysis; Revision 0
ER-AA-102-1000; Buried Piping Examination Procedure; Revision 2
ER-AA-102-005; Underground Piping and Tanks Integrity Program, Revision 5
ENG-ER-AA-102; Common ESP Training Guide; Revision 0
ACP 1211.16; Ultrasonic Thickness Measurement using Digital Thickness Gages; Revision 7
Duane Arnold Energy Center Underground Piping and Tanks Examination Plan; Revision 1
Report No. 1000995.401; APEC Survey – Duane Arnold Energy Center, August 22, 2011; Revision 0
NEI 09-14 Condition Assessment Plan for Buried Tanks, Revision 0
DAEC Underground Piping and Tanks Examination Plan, Revision 1
Report No. 19508-C-006; Integrity Assessment of Buried Pipe 16” GBC-002; October 23, 2012
Report No. 19508-C-002; Integrity Assessment of Buried Pipe 4” ELC-010; July 1, 2012
Report No. 19508-C-008; Integrity Assessment of Buried Pipe 18” HCC-008; October 24, 2012
Report No. 19508-C-012; Integrity Assessment of Buried Pipe 6” HBD-025; October 24, 2012
Report No. 1200723.401; GWT/UT Assessments at Duane Arnold Energy Center; January 15, 2013
CR 01891902; NRC Observation On Buried Piping Risk Ranking at DAEC
CE 1815022-02; GBC-002 Condition Evaluation

Report No. C40322; Corrpro Soil Sample Analysis Report for DAEC; August 10, 2010
WO 40036466; RHRSW ‘A’ ASME Section XI System Leakage Test
WO 01363518; River Water Supply ASME Section XI System Leakage Test
WO 40121807; Perform a Buried Piping Exam on GBC-002 South of the HPCI/RCI
CR 01815022; GBC002 RHRSW Pipe Found Below Min Wall During Buried Piping Exam
Report No. 2012-0454-1; GE Metallurgical Lab Report for RHR River Inlet; February 1, 2013
WO 40137334; Inspect Cathodic Protection System
Report No. NEER-RSC-13813; 2012 Cathodic Protection Systems At DAEC; August 13, 2012
CR 01892261; Potential Operability Concern for RHRSW line GBC-002
CR 01892263; POD Not Performed On GBC-001 Piping Based On GBC-002 Inspection

LIST OF ACRONYMS USED

AC	Alternating Current
ACP	Administrative Control Procedure
ADAMS	Agencywide Document Access Management System
AFP	Area Fire Protection
AOP	Abnormal Operating Procedure
ASME	American Society of Mechanical Engineers
AV	Apparent Violation
CAP	Corrective Action Program
CB	Control Building
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CRS	Control Room Supervisor
DAEC	Duane Arnold Energy Center
DRP	Division of Reactor Projects
EG-M	Electronic Governor Module
ESW	Emergency Service Water
HPCI	High Pressure Coolant Injection
HPP	Health Physics Procedure
IMC	Inspection Manual Chapter
IOD	Immediate Operability Determination
IP	Inspection Procedure
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LPCI	Low Pressure Coolant Injection
LPRM	Local Power Range Monitor
MSL	Main Steam Line
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OI	Operating Instruction
OOS	Out-of-service
OSM	Operations Shift Manager
OWA	Operator Workaround
PARS	Publicly Available Records System
PI	Performance Indicator
POD	Prompt Operability Determination
PRA	Probabilistic Risk Analysis
psi	Pounds Per Square Inch Gauge
RCE	Root Cause Evaluation
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RETS	Radiological Effluent Technical Specifications
RFO	Refueling Outage
RFP	Reactor Feed Pump

RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SAMP	Severe Accident Management Procedure
SBDG	Standby Diesel Generator
SBGT	Standby Gas Treatment
SBO	Station Blackout
SERP	Significance and Enforcement Review Panel
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SR	Surveillance Requirement
SRA	Senior Reactor Analyst
SSC	Structure, System, or Component
STP	Surveillance Test Procedure
TI	Temporary Instruction
TM	Temporary Modification
TIP	Traversing In-core Probe
TIS	Temperature Indicating Switch
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WARM	Work Activity Risk Management
WO	Work Order

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth G. O'Brien, Acting Director
Division of Reactor Projects

Docket No. 50-331
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Enclosure: Inspection Report 05000331/2013004
w/Attachment: Supplemental Information

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Letter from to Richard Anderson by Kenneth O'Brien dated November 14, 2013

SUBJECT: DUANE ARNOLD ENERGY CENTER – NRC INTEGRATED INSPECTION REPORT 05000331/2013004, PRELIMINARY WHITE FINDING

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