UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

November 14, 2017

Mr. Brian Sullivan
Site Vice President
Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360-5508

SUBJECT: PILGRIM NUCLEAR POWER STATION – INTEGRATED INSPECTION REPORT 05000293/2017003

Dear Mr. Sullivan:

On September 30, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Pilgrim Nuclear Power Station (PNPS). On October 18, 2017, the NRC inspectors discussed the results of this inspection with you and other members of your staff. The results of this inspection are documented in the enclosed report.

NRC inspectors documented seven findings of very low safety significance (Green) in this report. All seven findings involved violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the 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 I; the Director, Office of Enforcement; and the NRC Resident Inspector at PNPS. In addition, if you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC, 20555-0001; with copies to the Regional Administrator, Region I, and the NRC Resident Inspector at PNPS.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 *Code of Federal Regulations* (CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Arthur L. Burritt, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket No. 50-293
License No. DPR-35

Enclosure:
Inspection Report 05000293/2017003
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

SUBJECT: PILGRIM NUCLEAR POWER STATION – INTEGRATED INSPECTION REPORT 05000293/2017003 dated November 14, 2017

Distribution w/encl:
DDorman, RA
DLew, DRA
RLorson, DRP
DPelton, DRP
JYerokun, DRS
BWelling, DRS
ABurritt, DRP
MCatts, DRP
JVazquez, DRP
JPfingsten, DRP
PCataldo, DRP, SRI
BPinson, DRP, RI
PBoguszewski, DRP, RI
ACass, DRP, AA
JBowen, RI OEDO
RidsNrrPMPilgrim Resource
RidsNrrDorlLPL1 Resource
ROPReports Resource

DOCUMENT NAME: G:\DRP\BRANCH5\Inspection Reports\Final\2017\PIL IR17003 final.docx
ADAMS ACCESSION NUMBER: **ML17319A158**

☑ SUNSI Review		☑ Non-Sensitive ☐ Sensitive		☑ Publicly Available ☐ Non-Publicly Available	
OFFICE	RI/DRP	RI/DRP	RI/DRP		
NAME	PCataldo/ABurritt for	MCatts via email	ABurritt		
DATE	11/14/17	11/14/17	11/14/17		

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-293
License No.	DPR-35
Report No.	05000293/2017003
Licensee:	Entergy Nuclear Operations, Inc. (Entergy)
Facility:	Pilgrim Nuclear Power Station (PNPS)
Location:	600 Rocky Hill Road Plymouth, MA 02360
Dates:	July 1, 2017 through September 30, 2017
Inspectors:	E. Carfang, Senior Resident Inspector B. Pinson, Resident Inspector P. Boguszewski, Acting Resident Inspector P. Finney, Senior Resident Inspector B. Dionne, Health Physicist S. Pindale, Senior Reactor Inspector J. Ayala, Reactor Inspector M. Greenleaf, Reactor Inspector J. Pfingsten, Project Engineer J. Patel, Reactor Inspector T. Dunn, Reactor Inspector
Approved By:	Arthur L. Burritt, Chief Reactor Projects Branch 5 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY

IR 05000293/2017003; 07/01/2017 – 09/30/2017; PNPS; Maintenance Effectiveness, Routine Review of Problem Identification and Resolution Activities, Follow-Up of Events and Notices of Enforcement Discretion.

This report covered a three-month period of inspection by resident inspectors and announced baseline inspections performed by regional inspectors. The inspectors identified seven non-cited violations (NCVs), all of which were of very low safety significance (Green and/or Severity Level IV). The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)," dated October 28, 2016. Cross-cutting aspects are determined using IMC 0310, "Aspects Within Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated August 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 6.

Cornerstone: Mitigating Systems

- <u>Green</u>. An NRC-identified Green NCV of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified when Entergy did not establish an adequate abnormal operating procedure (AOP) to address loss of control room air conditioning. Specifically, until a revision was issued on April 27, 2017, this AOP did not include appropriate quantitative and qualitative acceptance criteria to ensure operators could maintain control room equipment during an accident scenario and perform the requirements of the procedure in the event of a loss of control room air conditioning. Entergy's corrective actions included a significant revision of AOP 2.4.149, "Loss of Control Room Air Conditioning," which separated the load shed list into four attachments and denoted the expected timeframes required for load shedding. Entergy entered this issue into the corrective action program (CAP) as condition report (CR) 2017-2600.

  The performance deficiency was more than minor because it was associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, Entergy provided an AOP that did not to ensure control room instrumentation could be maintained below equipment operating limits in accordance with design documents, and once revised, did not ensure sufficient direction was provided to operators to prioritize how loads are removed from service. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The SDP for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because while the performance deficiency could have affected the qualification of a mitigating structure, system, or component (SSC), the finding did not represent an actual loss of system or function. This finding had a cross-cutting aspect in the area of Human Performance, Design Margin, because Entergy did not maintain design margins through a systematic and rigorous process. Specifically, Entergy did not maintain design calculations for the main control room air conditioning system, and did not adequately translate the requirements into an AOP to maintain the operability of safety-

related equipment in the main control room following a loss of control room air conditioning. [H.6] (Section 1R12)

- Green. An NRC-identified Green NCV of Technical Specification (TS) 5.4.1.a, "Procedures," was identified because Entergy did not establish an appropriate preventive maintenance (PM) schedule for replacement of non-metallic parts internal to the 'A' safety relief valve (SRV) solenoid three-way operated valve. Specifically, between May 1993 and May 2017, the 'A' SRV solenoid coil (SV-203-3A) was not replaced for 20 years, which exceeded the environmental qualified life and replacement frequency specified in the vendor manual and Entergy's PM Basis document. As a result, on April 24, 2017, during the post-maintenance testing, high resistance was measured on SV-203-3A circuit that potentially affected 'A' SRV's ability to perform its safety function. Entergy's immediate corrective actions included replacing the solenoid valves on all four SRVs. Entergy entered this issue into the CAP as CRs 2017-06183, 2017-05472, 2017-05386, and 2017-05829.

  The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the inadequate PM frequency for the 'A' SRV solenoid coil resulted in a degraded connection causing high circuit resistance across the solenoid coil which challenged the reliability of the SRV safety function. The inspection staff and senior reactor analyst (SRA) determined that with the available technical information and testing, the screening questions in IMC 0609, Appendix A, "The SDP for Findings At-Power," may not adequately bound the performance deficiency. As such, in accordance with Section 5.0, "Screening," of IMC 0609, Appendix A, a bounding detailed risk assessment was conducted in accordance with Section 6.0, "Detail Risk Evaluation," of the appendix. The detailed risk evaluation concluded the finding was characterized as having very low safety significance (Green). The resulting change in core damage frequency of 6E-7 was dominated by medium break loss of coolant accidents (LOCAs) with the failure of the high pressure coolant injection (HPCI) system to run along with the failure to depressurize the reactor. The inspectors determined there was no cross-cutting aspects associated with this finding since it was not representative of current Entergy performance. (Section 4OA3.1.b.1)

- Green. An NRC-identified Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified in that Entergy did not correct a condition adverse to quality when they replaced differential pressure indication switch (DPIS)-2352, DPIS-1244, and DPIS-261 for the HPCI, reactor water cleanup, and low pressure core injection systems without upgrading their environmental qualification (EQ) status from the Division of Operating Reactors (DOR) Guidelines to 10 CFR 50.49 as required by 10 CFR 50.49(l). In response, Entergy conducted an operability assessment, which concluded that there were no immediate operability issues; and they will evaluate options for meeting 10 CFR 50.49 EQ criteria for the affected components. Entergy entered this issue into the CAP as CRs 2017-06652 and 2017-09330.

  The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone 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 failure to use replacement equipment qualified in accordance with 10 CFR 50.49(l) adversely affects the reliability of the HPCI, reactor water cleanup, and low pressure core injection systems. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The SDP for Findings At-Power," the inspectors determined the issue screened as having very low safety significance (Green) because the finding was a deficiency affecting the design or qualification of a mitigating SSC in which its operability or functionality was maintained. This finding had a cross-cutting aspect in Problem Identification and Resolution, Evaluation, because Entergy did not thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, Entergy did not properly evaluate a self-identified deficiency when they closed CR 2012-04248 without qualifying DPIS-2352, DPIS-1244, and DPIS-261 to the qualification requirements of 10 CFR 50.49. [P.2] (Section 4OA3.1.b.2)

- Green. A self-revealed Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," and TS 3.5.A, "Core Spray and Low Pressure Coolant Injection Systems," was identified when Entergy did not appropriately establish procedures for filling and venting the 'A' core spray (CS) system. As a result, the system was returned to service on May 21, 2017, with a 2-inch void in the 'A' CS system, which rendered it inoperable. The 'A' CS system was inoperable until Entergy filled and vented the system on June 7, 2017, which exceeded the TS allowed outage time. Entergy's corrective actions include immediately filling and venting the line, plans to revise procedural requirements for CS filling and venting, and providing a briefing to licensed operators on this event, its causes, and corrective actions. Entergy performed additional ultrasonic testing (UT) later on June 7 to verify the system was adequately filled. Entergy entered this issue into the CAP as CR 2017-6029.

  The performance deficiency was more than minor because it is associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, Entergy returned the 'A' CS system to service with a void in the discharge piping that made the pump inoperable, and the UT to verify the piping was full was not completed in a timely manner to ensure 'A' CS was operable when required in the Hot Shutdown, Startup, and Run modes. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The SDP for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not affect the design or qualification of a mitigating SSC and the finding did not represent a loss of system or function. This finding had a cross-cutting aspect in the area of Human Performance, Avoid Complacency, because individuals in the organization did not recognize and plan for the possibility of mistakes, latent issues, and inherent risk, even while expecting successful outcomes. Specifically, Entergy's plan to fill and vent the 'A' CS system failed to review and implement the requirements of PNPS 2.2.20 for dynamically venting the inverted loop in 'A' CS discharge piping. [H.12] (Section 4OA3.3)

Cornerstone: Barrier Integrity

- Green. A self-revealed Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," and TS 3.7.A.2, "Containment Systems – Primary Containment," was identified when Entergy did not appropriately establish procedures for maintenance on the HPCI turbine exhaust valves. As a result, the safety-related primary containment isolation check valves exceeded the 10-year disassembly and inspection interval and subsequently failed during testing. Corrective actions for this issue include the 2301-45 check valve was rebuilt, the 2301-74 check valve was disassembled, inspected, and cleaned, and the disassembly and inspection PM for the valves was changed from as required to every 10 years. Entergy entered this issue into the CAP as CR 2017-5075.

The performance deficiency was more than minor because it is associated with the SSC and Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events. Specifically, prior to July 27, 2017, Entergy's PM for the HPCI turbine exhaust check valves was inadequate to ensure the availability and reliability of SSC's required to maintain primary containment operable. In accordance with IMC 0609.04, "Initial Characterization of Findings," issued October 7, 2016, and IMC 0609, Appendix A, Exhibit 3, "The SDP for Findings At-Power," issued June 19, 2012, the inspectors determined that the finding was of very low safety significance (Green) because the finding does not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, or heat removal components or a reduction in function of hydrogen igniters in the reactor containment. This finding had a cross-cutting aspect of Problem Identification and Resolution, Resolution, because Entergy did not take effective corrective actions to address issues in a timely manner. Specifically, Entergy identified in 2016 that there were deficiencies in the PM program with the technical justification for deferring PMs and a 2011 CR directed a corrective action to specifically address the change in PM code that would have directed periodic maintenance on the valves. Entergy reasonably had two opportunities to identify that PMs were not performed within recommended guidelines and make appropriate changes as needed. [P.3] (Section 4OA2.2)

- Green. An NRC-identified Green NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified in that Entergy did not assure that the applicable design bases were correctly translated into specifications, drawings, procedures, and instructions; and did not verify the adequacy of design features by including suitable qualification testing of a prototype unit under the most adverse design conditions. Specifically, Entergy did not justify and document the activation energy (Ea) used to determine the thermal lifespan of silicon rubber gaskets used in the main steam isolation valve (MSIV) limit switches. Entergy used non-conservative Ea values without providing adequate justification when extending the qualified service life for the silicon rubber gaskets. In response, Entergy performed an immediate determination of operability; and they plan to properly identify, document, and justify the proper Ea for the silicon rubber gaskets. Entergy entered this issue into the CAP as CR 2017-09241.

  The performance deficiency was more than minor because if left uncorrected, it could have had the potential to lead to a more significant safety concern. Specifically, without using an adequate Ea, the MSIV limit switch assemblies could be have been allowed to exceed their qualified life. Also, the finding is associated with the Design Control attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of ensuring that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, using an incorrect Ea provided a non-conservative qualified service life value for the MSIV position indicating limit switches, and the MSIV limit switch assemblies would have exceeded their qualified life if left uncorrected. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 3 of IMC 0609, Appendix A, "The SDP for Findings At-Power," the inspectors determined the issue screened as having very low safety significance (Green) because it was a design deficiency confirmed not to result in an actual open pathway in the physical integrity of reactor containment (valves, airlocks, etc.), containment isolation system (logic and instrumentation), and heat removal components; and did not involve an actual reduction in function of hydrogen igniters in the reactor containment. This finding did not have a cross-cutting aspect because the performance deficiency did not reflect current licensee performance. (Section 4OA3.1.b.3)

- Green. A self-revealed Green NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and TS 4.7.A.2.a.3.2 and TS 4.7.A.2.a.3.4, "Primary Containment- Primary Containment Integrity," was identified because Entergy did not implement a vendor recommended modification to address MSIV stem damage caused by an unstabilized main poppet. As a result, the 1C and 1D MSIVs experienced damage that was identified during the failure of local leak rate testing (LLRT) of the valves. Entergy's corrective actions included overhauling the valves, adjusting packing on all eight MSIVs, and providing procedural guidance for closing a MSIV during low power operations. Entergy entered this issue into the CAP as CR 2017-5075.

  The performance deficiency was more than minor because it is associated with the SSC and Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events. Specifically, Entergy did not implement GE SIL 568 to address MSIV damage due to an unstabilized main poppet. This damage was observed in three MSIVs during the 2017 refueling outage (RFO). In accordance with IMC 0609.04, "Initial Characterization of Findings At-Power," issued June 19, 2012, the inspectors determined that the finding was of very low safety significance (Green) because the performance deficiency did not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, or heat removal components, or a reduction in function of hydrogen igniters in the reactor containment. The finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because Entergy did not evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, Entergy identified in 2015 that damage was occurring in the 1D MSIV, and the evaluation did not identify actions to address the vendor modification to correct the underlying issue. [P.2] (Section 4OA3.2)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. On August 10, 2017, operators reduced power to 45 percent to perform a main condenser thermal backwash. Operators returned the unit to 100 percent power the same day. On September 20, 2017, operators commenced a downpower to 80 percent due to a rising ultimate heat sink temperature. On September 21, 2017, operators downpowered an additional 10 percent to 70 percent due to ultimate heat sink temperatures. Operators returned the unit to full power on September 22, 2017. The unit remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04 – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- 'B' Residual heat removal (RHR) train during 'A' RHR train maintenance outage on July 5, 2017
- 'A' CS train while 'B' CS train was inoperable for 'B' CS logic system functional testing on July 18, 2017
- 'B' Salt service water (SSW) train during 'A' SSW train instrument calibration and functional test on July 19, 2017
- Reactor core isolation cooling (RCIC) system during HPCI system outage on August 8, 2017

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the Final Safety Analysis Report (FSAR), TSs, work orders (WOs), CRs, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted the system's performance of its intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether Entergy staff had properly identified equipment issues and entered them into the CAP for resolution with the appropriate significance characterization. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

.2 Full System Walkdown (71111.04S – 1 sample)

a. Inspection Scope

During the week of September 4, 2017, the inspectors performed a complete system walkdown of accessible portions of the 'A' emergency diesel generator (EDG), to verify the existing equipment lineup was correct. The inspectors reviewed operating procedures, surveillance tests, drawings, equipment line-up check-off lists, and the FSAR to verify the system was aligned to perform its required safety functions. The inspectors also reviewed electrical power availability, component lubrication and equipment cooling, hanger and support functionality, and operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify as-built system configuration matched plant documentation, and that system components and support equipment remained operable. The inspectors confirmed that SSCs were aligned correctly, free from interference from temporary services or isolation boundaries, environmentally qualified, and protected from external threats. Additionally, the inspectors reviewed a sample of related CRs and WOs to ensure Entergy appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

Resident Inspector Quarterly Walkdowns (71111.05Q – 5 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that Entergy controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan, and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for out of service, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- RCIC fire protection walkdown on July 7, 2017
- Reactor building 91' level on July 24, 2017
- HPCI quad room on July 27, 2017
- Control rod drive system quad room on August 1, 2017
- Standby gas treatment system room on August 1, 2017

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11Q – 2 samples)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on August 29, 2017, which involved a leak on the RHR heat exchanger, a loss of instrument air, and a main generator core monitor failure. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of AOPs and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

On September 27, 2017, during RCIC overspeed testing and drywell sump pump valve control switch replacements on the main control boards, inspectors observed control room activities to ensure command and control were effectively maintained by operators. The inspectors observed pre-shift briefings and reactivity control briefings to verify that the briefings met the criteria specified in Entergy Procedure EN-OP-115, "Conduct of Operations," Revision 21. Additionally, the inspectors observed operator performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q – 3 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on SSC performance and reliability. The inspectors reviewed system health reports, CAP documents, maintenance WOs, and maintenance rule basis documents to ensure that Entergy was identifying and properly evaluating performance problems within the scope of the maintenance rule. For each sample selected, the inspectors verified that the SSC was properly scoped into the maintenance rule in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by Entergy staff was reasonable. As applicable, for SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these SSCs to (a)(2). Additionally, the inspectors ensured that Entergy staff was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

- ‘B’ SSW train the week of July 10, 2017
- HPCI system the week of August 28, 2017
- Instrument air compressor K-117 and associated (a)(1) evaluation on August 30, 2017

The inspectors also reviewed Unresolved Item (URI) 05000293/2017001-1, Concern Regarding Ability to Declare EALs during Loss of Control Room Air Conditioning, regarding the potential to render several emergency action levels (EALs) ineffective. This URI was documented in NRC Integrated Inspection Report 05000293/2017001. To determine the adequacy of procedure 2.4.149, “Loss of Control Room Air Conditioning,” inspectors reviewed calculations, control room equipment, and emergency response procedures; and walked through load shedding procedures with operators and engineers.

b. Findings

The inspectors determined that sufficient equipment was maintained to declare all applicable HOT (greater than 212°F) condition EALs based on calculated heat-up rates in the control room. While numerous pieces of equipment would be removed from service under procedure 2.4.149, inspectors confirmed that the calculated time when control room heat loads would be required to be shed did not impact operators’ ability to make HOT condition EAL declarations. Specifically, Entergy performed a calculation under Engineering Change 71853 to determine if the temperatures would exceed the EQ limits of safety-related equipment located in the main control room during a loss of air conditioning. Entergy assumed that temperatures would increase to 119°F, before loads would be removed from service. In the model, a LOCA was assumed, and loads were required to be shed at 0.42 hours, 2.92 hours, 13.20 hours, and 35.55 hours after the loss of main control room air conditioning occurred. No loads that would impact the operators’ ability to declare an EAL were shed in the first two time periods. Furthermore, inspectors determined Entergy could reasonably achieve cold shutdown conditions within 13.20 hours, before de-energizing instruments needed to support EAL decisions. The equipment of concern of the URI was applicable to HOT condition EALs. URI 05000293/2017001-01, Concern Regarding Ability to Declare EALs during Loss of Control Room Air Conditioning, is closed.

Introduction. An NRC-identified Green NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified when Entergy did not establish an adequate AOP to address loss of control room air conditioning. Specifically, until a revision was issued on April 27, 2017, this AOP did not include appropriate quantitative and qualitative acceptance criteria to ensure operators could maintain control room equipment in an accident scenario and perform the requirements of the procedure in the event of a loss of control room air conditioning.

Description. In June 2016, inspectors identified concerns with the adequacy of Entergy AOP 2.4.149, "Loss of Control Room Air Conditioning." Since May 2012, Entergy entered AOP 2.4.149 nine times due to failures of the main control room air conditioning equipment. The main control room is required to remain at or below 120°F to ensure the main control room equipment remains operable. Main control room equipment temperatures above 120°F can result in multiple control equipment failures which could result in misleading indications and inadvertent system actuations. FSAR Section 7.1.8 stated that under no conditions would the loss of main control room air conditioning require the shutdown of the unit.

Inspectors identified that design calculation S&SA056, "Control Room and Cable Spreading Room Heatup Calculations," dated 1988, required in the event of a loss of main control room air conditioning that all main control room annunciators be turned off in order to not exceed the 120°F temperature limit. AOP 2.4.149 was reviewed, and did not include this requirement, only a note after Step 4.1.(14) that states heat loads can be further reduced by disabling annunciators and Section 4.1.(15) directs operators to immediately inform the operations manager if the control room reaches 115°F. The inspectors determined the procedure was inadequate because no direction was given to operators to shutdown the unit prior to exceeding 120°F and relied solely on the determination of the operations manager.

Based on the inspectors' questions, the licensee determined design calculation S&SA056 was out of date and not reflective of new modifications installed in the main control room (including replacement of annunciator bulbs with less heat generation). On December 14, 2016, the calculation was updated and Revision 15 of AOP 2.4.149 was issued on February 2, 2017. The new revision addressed the need to inform the operations manager when the main control room reached 90°F to discuss the need to shutdown the unit, and perform a load shed as described in Attachment 1. FSAR Section 7.1.8 was revised to reflect the new calculation assumptions and the possible need to shutdown the unit. The inspectors further determined Attachment 1 of procedure 2.4.149 provided a large list of loads for operators to shed to ensure the main control room remained below 120°F, but provided no guidance in the order of loads to be shed. In particular, no priority was made between shedding equipment that provided functions important to safety (such as radiation monitors, nuclear instruments, jet pump instrumentation) and control room lighting. As a corrective action, Entergy entered the issue into the CAP as CR 2017-2600. Entergy performed a significant revision of AOP 2.4.149, which separated the load shed list into four attachments and denoted the expected timeframes required for load shedding. Control room temperature monitoring is directed every five minutes, and specific guidance is provided to operators regarding the potential impact of equipment on EAL declarations. Entergy also updated the FSAR to incorporate design assumptions in calculation S&SA056. The inspectors reviewed the procedure changes and determined Entergy had appropriately revised the procedure.

Analysis. The inspectors determined that Entergy did not provide appropriate qualitative and quantitative criteria in AOP 2.4.149 to ensure operators could maintain control room equipment during an accident scenario and perform the requirements of the procedure in the event of a loss of control room air conditioning. The inspectors determined this was a performance deficiency that was within Entergy's ability to foresee and correct and should have been prevented. The performance deficiency was more than minor because it is associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, Entergy provided an AOP that did not to ensure control room instrumentation could be maintained below equipment operating limits in accordance with design documents, and once revised, did not ensure sufficient direction was provided to operators to prioritize how loads are removed from service. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The SDP for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because while the performance deficiency could have affected the qualification of a mitigating SSC, the finding did not represent an actual loss of system or function. This finding had a cross-cutting aspect in the area of Human Performance, Design Margin, because Entergy did not maintain design margins through a systematic and rigorous process. Specifically, Entergy did not maintain design calculations for the main control room air conditioning system, and did not adequately translate the requirements into an AOP to maintain the operability of safety-related equipment in the main control room following a loss of control room air conditioning. [H.6]

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states in part that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures, or drawings and that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, prior to April 27, 2017, Entergy did not establish adequate instructions in AOP 2.4.149, "Loss of Control Room Air Conditioning," which provides instructions on maintaining control room temperatures. Specifically, AOP 2.4.149 lacked adequate instructions to ensure main control room temperatures would not exceed the operability limits of control room instrumentation and ensure the availability of equipment important to safety. Entergy's corrective actions included a significant revision of AOP 2.4.149, which separated the load shed list into four attachments and denoted the expected timeframes required for load shedding. Because this issue is of very low safety significance (Green) and Entergy entered the issue into the CAP as CR 2017-2600, this finding is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000293/2017003-01, Inadequate Procedure for Loss of Control Room Air Conditioning)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 5 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that Entergy performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that Entergy personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When Entergy performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with the station's probabilistic risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the TS requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- Planned elevated risk during ‘B’ EDG inoperability on July 11, 2017
- Planned maintenance for fire protection ring header corrective maintenance on July 27, 2017
- Planned elevated risk during HPCI outage on August 7, 2017
- Unplanned elevated risk to identify cause of ‘B’ EDG overspeed trip reset mechanism failure on August 14, 2017
- Planned elevated risk for 2-year PM on the ‘A’ EDG the week of August 21, 2017

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 5 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions based on the risk significance of the associated components and systems:

- ‘A’ and ‘B’ reactor building closed cooling water heat exchanger macrofouling indicated by rising reactor building closed cooling water differential pressure the week of July 10, 2017
- ‘B’ EDG following high jacket water heat exchanger temperatures during the monthly surveillance run on July 11, 2017
- 115kV line maintenance with line 113 powering the shutdown transformer on July 17-21, 2017
- HPCI turbine exhaust check valve hinge damage the week of July 20, 2017
- ‘B’ EDG overspeed trip lever repairs on August 14, 2017

The inspectors evaluated the technical adequacy of the operability determinations to assess whether 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 TSs and FSAR to Entergy’s evaluations to determine whether the components or systems were operable. The inspectors confirmed, where appropriate, compliance with bounding limitations associated with the evaluations. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled by Entergy.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 5 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with the information in the applicable licensing basis and/or design basis documents, and that the test results were properly reviewed and accepted and problems were appropriately documented. The inspectors also walked down the affected job site, observed the pre-job brief and post-job critique where possible, confirmed work site cleanliness was maintained, and witnessed the test or reviewed test data to verify quality control hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

- Hydraulic control unit 30-19 accumulator high level switch replacement on July 14, 2017
- Standby gas treatment exhaust fan relay replacement on July 26, 2017
- Control room EDG kilowatt meter repair after 'B' EDG did not achieve rated voltage during monthly surveillance test on August 15, 2017
- 'E' SSW pump rebalancing to address increased vibrations on August 16, 2017
- 'A' EDG 2-year overhaul the week of August 28, 2017

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 4 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant SSCs to assess whether test results satisfied TSs, the FSAR, and Entergy procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied.

Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

- 8.5.4.1, High Pressure Coolant Injection System Pump and Valve Quarterly and Biennial Comprehensive Operability the week of August 9, 2017 (in-service test)
- 8.F.38.1, Diesel Generator Instrument Calibration and Functional Test the week of August 21, 2017
- 8.M.2-2.10.8.5, Diesel Generator 'A' Initiation by Loss of Offsite Power Logic Test on August 29, 2017

- 8.9.1, Emergency Diesel Generator and Associated Emergency Bus Surveillance the week of September 11, 2017

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06 – 6 samples)

a. Inspection Scope

The inspectors reviewed the treatment, monitoring, and control of radioactive gaseous and liquid effluents. The inspectors used the requirements in 10 CFR Part 20; 10 CFR Part 50, Appendix I; TS; Offsite Dose Calculation Manual (ODCM); applicable industry standards; and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors conducted in-office review of the PNPS's 2016 annual radioactive effluent, radioactive effluent program documents, FSAR, ODCM, and applicable event reports.

Walk-downs and Observations (1 sample)

The inspectors walked down the gaseous and liquid radioactive effluent monitoring and filtered ventilation systems to assess the material condition and verify proper alignment according to plant design. The inspectors also observed potential unmonitored release points and reviewed radiation monitoring system surveillance records and the routine processing and discharge of gaseous and liquid radioactive wastes.

Calibration and Testing Program (1 sample)

The inspectors reviewed gaseous and liquid effluent monitor instrument calibration, functional test results, and alarm setpoints based on National Institute of Standards and Technology calibration traceability and ODCM specifications.

Sampling and Analyses (1 sample)

The inspectors reviewed: radioactive effluent sampling activities, representative sampling requirements, compensatory measures taken during effluent discharges with inoperable effluent radiation monitoring instrumentation, the use of compensatory radioactive effluent sampling, and the results of the inter-laboratory and intra-laboratory comparison program, including scaling of hard-to-detect isotopes.

Instrumentation and Equipment (1 sample)

The inspectors reviewed the methodology used to determine the radioactive effluent stack and vent flow rates to verify that the flow rates were consistent with TS/ODCM and FSAR values. The inspectors reviewed radioactive effluent discharge system surveillance test results based on TS acceptance criteria. The inspectors verified that high-range effluent monitors used in emergency operating procedures are calibrated and operable and has post-accident effluent sampling capability.

Dose Calculations (1 sample)

The inspectors reviewed: changes in reported dose values from the previous annual radioactive effluent release reports, several liquid radioactive waste discharge permits, the scaling method for hard-to-detect radionuclides, ODCM changes, land use census changes, public dose calculations (monthly, quarterly, annual), and any records of abnormal gaseous or liquid radioactive releases.

Problem Identification and Resolution (1 sample)

The inspectors evaluated whether problems associated with the radioactive effluent monitoring and control program were identified at an appropriate threshold and properly addressed in Entergy's CAP.

b. Findings

No findings were identified.

2RS7 Radiological Environmental Monitoring Program (71124.07 – 3 samples)

a. Inspection Scope

The inspectors reviewed the Radiological Environmental Monitoring Program (REMP) to validate the effectiveness of the radioactive gaseous and liquid effluent release program and implementation of the Groundwater Protection Initiative (GPI). The inspectors used the requirements in 10 CFR Part 20; 40 CFR Part 190; 10 CFR Part 50, Appendix I; TSs; ODCM; Nuclear Energy Institute (NEI) 07-07; and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: PNPS's Annual Radiological Environmental Operating Report for 2016, REMP program audits, ODCM, 2016 land use census, FSAR, and inter-laboratory comparison program results.

Site Inspection (1 sample)

The inspectors walked down various environmental dosimeters (optically stimulated luminescent dosimeters), air sampling, groundwater monitoring wells, and surface water sampling locations. The inspectors also reviewed associated calibration and maintenance records. The inspectors observed the sampling of various environmental media as specified in the ODCM and reviewed any anomalous environmental sampling events including assessment of any positive radioactivity results. The inspectors also reviewed the ODCM. The inspectors verified the operability and calibration of the meteorological tower instruments and meteorological data readouts. The inspectors reviewed environmental sample laboratory analysis results, laboratory instrument measurement detection sensitivities, results of the laboratory quality control program audit, and the inter- and intra-laboratory comparison program results.

GPI Implementation (1 sample)

The inspectors reviewed: groundwater monitoring results; changes to the GPI program since the last inspection; anomalous results or missed groundwater samples; leakage or spill events, including entries made into the decommissioning files (10 CFR 50.75(g)); evaluations of surface water discharges; and Entergy's evaluation of any positive groundwater sample results, including appropriate stakeholder notifications and effluent reporting requirements.

The inspectors reviewed the groundwater monitoring program as it applies to selected potential leaking SSCs and the results of environmental remediation performed since the previous inspection.

Problem Identification and Resolution (1 sample)

The inspectors evaluated whether problems associated with the REMP, GPI, and Meteorological Monitoring Program were identified at an appropriate threshold and properly addressed in Entergy's CAP.

b. Findings

No findings were identified.

One observation concerning the implementation of the NEI 07-07 GPI is provided in Section 4OA5.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Mitigating Systems Performance Index (3 samples)

a. Inspection Scope

The inspectors reviewed Entergy's submittal of the Mitigating Systems Performance Index for the following systems for the period of July 1, 2016, through June 30, 2017:

- High pressure injection system
- Heat removal system
- Residual heat removal system

To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7. The inspectors also reviewed Entergy's operator narrative logs, CRs, Mitigating System Performance Index derivation reports, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 3 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify Entergy entered issues into the CAP at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. 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 CAP and periodically attended CR screening meetings. The inspectors also confirmed, on a sampling basis, that, as applicable, for identified defects and non-conformances, Entergy performed an evaluation in accordance with 10 CFR Part 21.

b. Findings

No findings were identified.

.2 Annual Sample: HPCI Turbine Exhaust Check Valve Failures Exceed Primary Containment Leakage Limit

The inspectors performed an in-depth review of Entergy's root cause evaluation and corrective actions associated with CR 2017-5075, 10 CFR 50 Appendix J Leak Rate Criteria Exceeded. Specifically, on April 22, 2017, while Entergy was performing LLRT on the HPCI turbine exhaust line, the associated check valve test results failed to meet established acceptance criteria.

The inspectors assessed Entergy's problem identification threshold, cause analyses, extent of condition reviews, and the prioritization and timeliness of Entergy's corrective actions to determine whether Entergy was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of Entergy's CAP and 10 CFR Part 50, Appendix B. In addition, the inspectors performed field walkdowns and interviewed engineering personnel to assess the effectiveness of the implemented corrective actions.

b. Findings

Introduction. A self-revealed Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," and TS 3.7.A.2, "Containment Systems –

Primary Containment," was identified when Entergy did not appropriately establish procedures for maintenance on the HPCI turbine exhaust valves. As a result, the safety-related primary containment isolation check valves exceeded the 10-year disassembly and inspection interval and subsequently failed during testing.

Description. On April 22, 2017, during Pilgrim's RFO, Entergy performed LLRT of the HPCI turbine exhaust check valves, 2301-74 and 2301-45. Both valves failed the test when they showed greater than 100 standard liters per minute (SLM) of leakage, which exceeded the acceptance criteria of 7.89 SLM. An exact leak rate could not be obtained because the line between them could not be pressurized due to the leakage through the valves exceeding the capacity of the testing equipment.

HPCI is an emergency core cooling system that provides coolant inventory to the reactor vessel to prevent fuel damage in the event of a postulated small break LOCA. The HPCI pump is a turbine driven pump powered by reactor steam. On a HPCI initiation, steam from the reactor is sent to the HPCI turbine and exhausted to the suppression pool. The piping that connects the HPCI turbine exhaust to the suppression pool contains two primary containment isolation check valves. Primary containment isolation valves are required to close in order to isolate primary containment and contain fission products released from the reactor system following a design basis accident. The HPCI turbine exhaust line does not represent an open pathway in the physical integrity of reactor containment because all leakage through the HPCI turbine exhaust valves is exhausted into the suppression pool, where it is scrubbed by water and remains in the suppression pool atmosphere.

The inspectors reviewed Entergy's root cause evaluation under CR 2017-5075, which determined the cause was that the HPCI turbine exhaust check valve, 2301-45, was in service for 22 years without a disassembly and inspection PM performed. The Entergy Preventive Maintenance Basis Template requires a 10-year disassembly and inspection PM on the HPCI turbine exhaust check valves. Entergy's root cause determined that the HPCI turbine exhaust valves previously had a 10-year inspection and disassembly PM, but sometime between 1995 and 2010, the PM frequency was changed to "as required." In addition, HPCI check valve 2301-74 could not meet its LLRT administrative limits at the end of the 2015 RFO. Administrative limits are identified to determine when a single valve is performing in a manner that requires correction. Immediate corrective actions are not always necessary, however, provided the redundant valve in the line can maintain the TS function to limit leakage through the pathway. Entergy delayed the repair of the 2301-74 check valve from the 2015 RFO to the 2017 RFO. The subsequent failure of the 2301-45 valve during the 2017 RFO led to a condition that exceeded the TS value.

The inspectors reviewed Entergy fleet procedure EN-DC-335, "Preventive Maintenance Basis Template," which requires Preventive Maintenance Basis Template deviations to contain sufficient technical basis documentation providing a clear and concise justification why the Preventive Maintenance Basis Template deviation is appropriate. Entergy's root cause found that the HPCI turbine exhaust check valves had been incorrectly coded in accordance with fleet procedure EN-DC-153, "Preventative Maintenance Component Classification." The correct code for the HPCI turbine exhaust valve is a PMO code 2, high critical, low duty cycle, and severe environment. However, the valves were coded as PMO code 9, non-critical. Check valves with a PMO code 2 have a 10-year disassembly and inspection PM, whereas check valves with a PMO code 9 have an “as required” disassembly and inspection PM.

In 2011, after a series of repeat failures on valve 2301-74, Entergy performed an apparent cause evaluation (CR 2011-2181) to determine the cause of the repeat failures. One of the corrective actions directed by the apparent cause evaluation was the verification of the PMO code of the 2301-74 valve in CR 2011-341. The corrective action response determined the valve was coded as PMO code 9, but should have been coded as PMO code 2. An engineering change was written to change the PMO code but was never implemented. Corrective actions only directed the writing of the engineering change, but not the implementation of the change. Additionally, CR 2016-2061, which addresses issues identified in Engineering Programs, a general concern was identified in the PM program regarding PM deferrals lacking adequate technical justification. The lack of adequate technical justification to change the PM from 10 years to “as required” led to the failure of the valves and an inoperable primary containment.

On May 17, 2017, Entergy completed repairs on both check valves. Entergy rebuilt the 2301-45 check valve, disassembled, inspected, and cleaned the 2301-74 check valve, and lapped both valve seats. The post-work LLRT was performed satisfactorily with results of 0.182 SLM for the 2301-45 check valve and 0.070 SLM for the 2301-74 check valve. In addition, Entergy changed the disassembly and inspection PM for the valves from “as required” to every 10 years on July, 27, 2017. Entergy entered this issue into their CAP as CR 2017-5075.

Analysis. The inspectors determined that Entergy established an inadequate inspection and disassembly PM for the HPCI turbine exhaust primary containment isolation check valves. This was a performance deficiency that was reasonably within their ability to foresee and correct and should have been prevented. The performance deficiency was more than minor because it is associated with the SSC and Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events. Specifically, prior to July 27, 2017, Entergy’s PM for the HPCI turbine exhaust check valves was inadequate to ensure the availability and reliability of SSC’s required to maintain primary containment operable. In accordance with IMC 0609.04, “Initial Characterization of Findings,” issued October 7, 2016, and IMC 0609, Appendix A, Exhibit 3, “The SDP for Findings At-Power,” issued June 19, 2012, the inspectors determined that the finding was of very low safety significance (Green) because the finding does not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, or heat removal components or a reduction in function of hydrogen igniters in the reactor containment.

This finding had a cross-cutting aspect of Problem Identification and Resolution, Resolution, because Entergy did not take effective corrective actions to address issues in a timely manner. Specifically, Entergy identified in 2016 that there were deficiencies in the PM program with the technical justification for deferring PMs and a 2011 CR directed a corrective action to specifically address the change in PM code that would have directed periodic maintenance on the valves. Entergy reasonably had two opportunities to identify that PMs were not performed within recommended guidelines and make appropriate changes as needed. [P.3]

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, prior to July 27, 2017, Entergy did not appropriately prescribe instructions or procedures for maintenance on the HPCI turbine exhaust valves. Specifically, Entergy changed the disassembly and inspection PM frequency from 10 years to "as required" without a proper justification, which resulted in the safety-related primary containment isolation check valves exceeding their recommended disassembly and inspection interval and subsequently failing during testing.

TS 3.7.A.2, "Containment Systems – Primary Containment," states, in part, that primary containment integrity shall be maintained at all times when the reactor is critical. Surveillance Requirement 4.7.A 2.a.3 states that primary containment overall rate acceptance criteria is $1.0L_a$, which is equal to 210 SLM standard liters per minute. Contrary to the above, from approximately May 20, 2015 to April 9, 2017, primary containment leakage through the HPCI turbine exhaust line (Penetration X-223) exceeded $1.0L_a$.

Entergy entered the issue into the CAP as CR 2017-5075. Entergy's immediate corrective actions included rebuilding the 23-CK-2301-45 check valve, disassembling and cleaning the 23-CK-2301-74 check valve, and lapping the valve seats. Because this violation was of very low safety significance (Green) and was entered into Entergy's CAP as CR 2017-5075, it is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. (**NCV 05000293/2017003-02, HPCI Turbine Exhaust Check Valve Failures Exceed Primary Containment Leakage Limit**)

.3 Annual Sample: Station Blackout Diesel Generator Failed to Control Load

a. Inspection Scope

The inspectors performed an in-depth review of Entergy's adverse cause analysis (ACA) and corrective actions associated with CR 2016-9211, Station Blackout Diesel Generator (SBODG) Speed Control Issues, and CR 2016-9989, SBODG Potentiometer Minimum Temperature Requirements. Specifically, during the November 22, 2016, quarterly surveillance test, the SBODG did not control the output of the SBODG within acceptance criteria.

The inspectors assessed Entergy's problem identification threshold, cause analyses, extent of condition reviews and the prioritization and timeliness of Entergy's corrective actions to determine whether Entergy was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of Entergy's CAP and 10 CFR Part 50, Appendix B. In addition, the inspectors performed field walkdowns and interviewed engineering personnel to assess the effectiveness of the implemented corrective actions.

b. Findings and Observations

No findings were identified.

Entergy identified two potential causal factors for the failure of the SBODG to maintain required speed. The first causal factor was the speed adjust potentiometer could have a high resistance spot on the internal resistor or wiper which affected the control signal being sent to the electric governor. The second causal factor is a degraded switch for isochronous operation.

As part of the ACA, Entergy developed corrective action 9 to troubleshoot the isochronous operation switch, to determine if it was actually causal to the issue. The original due date of the trouble shooting was March 16, 2017, however, a due date extension was granted because a new potentiometer was installed. This action was extended, then closed on May 24, 2017, to a new corrective action 13, to inspect the contact for the isochronous-droop switch by July 22, 2017. This corrective action does not require the SBODG to be running. Corrective action 13 was then extended to September 30, 2017, with results evaluated by October 7, 2017, to update the ACA. On September 25, 2017, the resistance reading directed by corrective action 13 found the resistance was within the expected range, after inspectors questioned the timeliness of the corrective action.

In total, this ACA had 10 original corrective actions with five additional corrective actions identified. There were nine due date extensions and two new corrective actions were created to finish previous corrective actions that were closed. Inspectors identified a performance deficiency in that actions to address a causal factor that potentially impacted isochronous mode switch performance for the SBODG was untimely, based on EN-LI-102, however, when the corrective action was implemented, the equipment test results were within acceptable values. This issue was determined to be minor because it was related to equipment performance and no equipment operability or functionality was significantly affected. In accordance with IMC 0612, "Power Reactor Inspection Reports," the above issue constituted a violation of minor significance that is not subject to enforcement action in accordance with the Enforcement Policy. Entergy entered the inspector's observations into their CAP as CR 2017-10416.

.4 Annual Sample: Corrective Actions from Cybersecurity Related Findings

a. Inspection Scope

On July 12, 2017, inspectors completed a problem identification and resolution sample to review corrective actions taken in response to a previous cybersecurity-related NRC finding. The results of this inspection sample are documented in NRC Inspection Report 05000293/2017405 (Agencywide Documents Access and Management System Accession No. ML17244A109), issued on September 5, 2017.

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

.1 Plant Events

a. Inspection Scope

For the plant event listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, “Reactive

Inspection Decision Basis for Reactors," for consideration of potential reactive inspection activities. As applicable, the inspectors verified that Entergy made appropriate emergency classification assessments and properly reported the event in accordance with 10 CFR 50.72 and 50.73. The inspectors reviewed Entergy's follow-up actions related to the events to assure that Entergy implemented appropriate corrective actions commensurate with their safety significance.

- High resistance on 'A' SRV solenoid circuit on April 24, 2017

Following this event, Entergy initiated a CR on May 17, 2017, documenting that the PM replacement frequency of the SRV solenoid coils had been based on non-conservative information. In response to this issue, three regional inspectors conducted additional follow-up inspection focused on EQ documentation and associated PM frequencies for selected electrical components. The inspectors interviewed station personnel, conducted plant walkdowns, and reviewed documentation to assess the extent of condition for this issue.

b. Findings

1. Introduction. An NRC-identified Green NCV of TS 5.4.1.a, "Procedures," was identified because Entergy did not establish an appropriate PM schedule for replacement of non-metallic parts internal to the 'A' SRV solenoid three-way operated valve.

Description. At Pilgrim, the nuclear system pressure relief system is comprised of four automatically actuated SRVs. Each relief valve is provided with a power actuated solenoid valve capable of opening the valve at any steam pressure above 100 pounds per square inch (psig), and capable of holding the valve open until the steam pressure decreases to approximately 50 psig. The SV-203-3A is the solenoid three-way operated valve for the 'A' SRV. FSAR Section 4.4, states the automatic depressurization feature of the nuclear system pressure relief system operates to reduce the reactor pressure so that the low pressure coolant injection (LPCI) and the CS systems can operate to re-flood the core following postulated small break LOCA. In addition, the manual initiation of the SRVs provides depressurization for transients and accidents in which the main heat sink is unavailable.

On April 20, 2017, during the RFO, Entergy replaced the 'A' SRV pilot valve and reinstalled the associated solenoid operated three-way valve. Following reinstallation, on April 24, 2017, post-maintenance testing was performed measuring circuit resistance from C156 Alternate Shutdown Panel through the solenoid coil using a Volt-Ohm-Meter. The circuit resistance displayed was "OL," indicating the resistance is greater than the meter can measure. Although it was not documented which range the meter was set on before using it, Entergy considered it as a high resistance measured across the solenoid coil that exceeded the acceptance range of 144 to 164 ohms. As a result, the solenoid was replaced and CR 2017-04203 was written to document this issue. Subsequently, prior to restart, Entergy performed an extent of condition review and replaced solenoids on the remaining three SRVs in May 2017. The 'B', 'C', and 'D' SRV solenoids did not indicate any signs of degradation during previous surveillance tests.

On May 11, 2017, the 'A' SRV solenoid was sent to Altran for electrical testing and forensic inspection. The testing initially measured a 2.3 megaohm resistance compared to the coil's internal resistance of 143 to 163 ohms. Further testing showed that with 30

Vdc applied, the solenoid coil energized and resistance readings were within the acceptance range. Two days later, additional electrical testing and resistance measurement results varied from 170 to 1100 ohms. Forensic inspections found corrosion product accumulation on the crimp connection and wires that created the high resistance, as measured by a low voltage digital multi-meter. Entergy determined that this resistance measurement was not representative of actual coil resistance because the corrosion product layer inhibited the operation of a 9 Volt battery digital multi-meter. Application of 30 Vdc was sufficient to overcome the corrosion product layer, allowed the valve to actuate, and allowed the multi-meter to obtain a resistance measurement more representative of actual coil resistance. The report concluded the variability of the resistance measurements was inconsequential because the valve actuated appropriately during all subsequent electrical testing at ambient and elevated temperatures.

Altran performed functional testing with full load pressure applied to the valve and increased the temperature to the maximum service temperature of 235°F, and observed that each time voltage was applied, the solenoid valve energized. The inspectors noted that pick up voltage would increase as temperature in the test chamber was raised. At 235°F, voltage required for the valve to actuate increased to a value between 65 and 75 Vdc. The inspectors determined that this would be an acceptable voltage as the minimum voltage available in the plant was 101 Vdc.

Entergy's failure analysis report determined the most plausible cause of the high resistance reading was due to the degraded, corroded crimp connection between the stranded coil lead and the solid coil winding wire. This crimp connection was located encapsulated in the potting material associated with the coil, as such, vibration would not have any impact on the crimp. Based on the review of test results and forensic inspection, the inspectors determined that the solenoid valve would have performed its function under normal plant operating conditions. The inspectors noted that there was no post-accident type testing performed by Entergy to demonstrate valve functionality under design basis accident conditions.

The inspectors reviewed the overall cumulative installed history for all four SRV solenoids to determine the age in service prior to removal in May 2017. The inspectors found the age in service for all four SRV solenoids as shown in the table below.

SRV	Solenoid Coil	O-rings (internal)
3A (Serial No. 107)	20 years	14 years
3B (Serial No. 106)	12 years	6 years
3C (Serial No. 104)	12 years	6 years
3D (Serial No. 26)	4 years	4 years

Additionally, the inspectors reviewed the EQ report, vendor manual, work history, and PM documents associated with the 'A' SRV solenoid. The inspectors found that the subject solenoid was environmentally qualified to ensure it will function in a harsh environment. It was qualified for a period of 10 years at a normal base service temperature of 240°F in a normal ambient temperature of 150°F, per the manufacturer's EQ documentation. The report did not state any specific maintenance requirements during the 10 year qualified service life period. However, it stated electrical components, including solenoid coil and terminal boards, elastomer seals, and valve seat inserts be replaced after 10 years of service. The inspectors also reviewed the vendor manual which provided a replacement frequency of 10 years for seat inserts, rubber O-rings, and solenoid coil. Additionally, the inspectors found that Entergy's Preventive Maintenance Basis document, though inactive in their system, stated that both the Entergy PM template and Electric Power Research Institute recommend replacement intervals of 10 years. Finally, the inspectors reviewed Pilgrim's PM replacement schedules and found that O-rings were being replaced every 15 years and solenoid coils were being replaced every 32 years. The inspectors determined this was a nonconformance with the EQ report, vendor manual, and Entergy Preventive Maintenance Basis Template.

The inspectors determined Entergy used a non-conservative value for determining qualified service life of Target Rock solenoid operated three-way valves. Entergy used a previous EQ report, which was for the Target Rock Solenoid Operated Globe Valve, that calculated service life solely based on the ambient temperature of 150°F with resulting service life of 32 years for the solenoid coil. The correct EQ report for the Target Rock SRV solenoid operated three-way valves was reviewed and accepted by Entergy in 1990, and considered the heat rise due to solenoid mounted on the SRV body and thermal conductance heat transfer from the main steam line to SRV. The EQ report documented the maximum service temperature the solenoid coil and valve could experience is 235° F due to main steam SRV heating in an ambient 150°-F environment. The EQ report used service temperature of 240°F in qualifying solenoid valves for a period of 10 years.

The inspectors reviewed Pilgrim's procedure 1.8.1, "Administration of Station Predefine," which defines PM requirements as any task that must be periodically performed which may satisfy regulatory requirements. Further it defines qualification maintenance requirements (QMR) as any unique maintenance requirements for the EQ component in order to maintain its qualification. The procedure stated that requirements found in QMR are derived from the equipment qualification data file and are in addition to routine maintenance. The inspectors reviewed Entergy's procedure EN-DC-324, "Preventive Maintenance Program," which lists key elements of the PM program, including the development and maintenance of Preventive Maintenance Basis Template and Preventive Maintenance Standard Strategies for high and low critical components. EN-DC-324 also requires Preventive Maintenance Basis databases remain current with plant configuration and practices, and approval be obtained for deviations from approved Preventive Maintenance Basis Templates or Strategies. EN-DC-335, "Preventive Maintenance Basis Templates," defines PM evaluations as process by which a Preventive Maintenance Basis Template is applied to a component to arrive at the Preventive Maintenance Standard Strategy for that component. The Preventive Maintenance Standard Strategy is then evaluated against commitments, operating experience, manufacturer recommendations, and plant history to arrive at the most applicable and effective PM strategy for that equipment. EN-DC-335 requires that a PM evaluation be performed for critical components when existing Preventive Maintenance Basis Template task frequency change or scope change.

The inspectors determined that Entergy did not maintain the Preventive Maintenance Basis Template in an active status. The inspectors determined that Entergy did not perform a PM evaluation when deviating from manufacturer recommended maintenance and from the Preventive Maintenance Task Frequency specified in the Preventive Maintenance Basis Template. The inspectors also determined that Entergy's QMR document did not identify all maintenance tasks (i.e. replacement of elastomer seals, solenoid coil, terminal board, and valve seat inserts) that were in the equipment qualification data file for the Target Rock SRV solenoid valve.

Based on the information above, the inspectors determined that 'A' SRV solenoid was installed in the plant for greater than its qualified life. The inspectors determined that Entergy's SRV solenoid valve PM frequency was not adequate. Entergy's electrical testing of the valve to determine the ability of the valve to operate as intended under various plant operating condition with as-found resistance did not include testing representing the plant operating conditions during the small break LOCA. As a result, the inspectors determined that the valve likely would not have performed its required safety function during a design basis small break LOCA. Entergy's immediate corrective actions included replacing the solenoid valves on all four SRVs. Entergy also completed an EQ evaluation to determine the qualified life based on the maximum service temperature of 235°F and using the Arrhenius equation. Entergy determined the qualified life to be 13.32 years.

Analysis. The inspectors determined that Entergy not establishing an appropriate PM schedule for the SRV solenoid valve – specifically, a 10 year replacement interval for solenoid coil and terminal boards, rubber O-rings, and valve seat inserts – was a performance deficiency that was within Entergy's ability to foresee and correct, and should have been prevented. The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the inadequate PM frequency for the 'A' SRV solenoid coil resulted in a degraded connection causing high circuit resistance across the solenoid coil which challenged the reliability of the SRV safety function. The inspection staff and SRA determined that with the available technical information and testing, the screening questions in IMC 0609, Appendix A, "The SDP for Findings At-Power," may not adequately bound the performance deficiency. As such, in accordance with Section 5.0, "Screening," of IMC 0609, Appendix A, a bounding detailed risk assessment was conducted in accordance with Section 6.0, "Detail Risk Evaluation" of the appendix. The detailed risk evaluation concluded the finding was characterized as having very low safety significance (Green). The resulting change in core damage frequency of 6E-7 was dominated by medium break LOCA with the failure of the HPCI system to run along with the failure to depressurize the reactor.

The SRA determined that licensee testing at a laboratory facility demonstrated that the solenoid, under normal loading, would likely function within acceptable dc voltage ranges. As such, the 'A' SRV was assumed to have the nominal failure probability for internal and external events that did not expose the valve to a harsh environment. However, no testing was conducted in harsh environment conditions, such as small, medium, and large break LOCA conditions, therefore, it was assumed that the 'A' SRV would fail and could not be recovered. For the 'B', 'C', and 'D' SRVs, based on the as-found conditions and Entergy's analysis, the failure probability was left unchanged at the nominal.

Main steam line and feedwater line breaks along with inadvertent opened relief valves were screened out of consideration. Main steam line and feedwater line breaks are generally excluded from Standardized Plant Analysis Risk since, for boiling water reactors, they generally contribute to less than one percent of the core damage frequency. Inadvertent opened relief valves were screened out because the energy from the reactor would be directed to the torus where a large amount of energy would be absorbed before the environment in containment would become a challenge to the 'A' SRV.

A detailed risk evaluation was performed using SAPHIRE 8.1.5 and Pilgrim Standardized Plant Analysis Risk Version 8.5. The 'A' SRV was set to a failure of 'true' for small, medium, and large break LOCA conditions. The exposure time was determined to be one year. The resulting change in core damage frequency was approximately 6E-7. The dominant accident sequences were medium break LOCA with the failure of the HPCI system to run (given that it was started) along with the failure to depressurize the reactor.

Given that the internal events resulted in a change in core damage frequency of greater than 1E-7, an evaluation of external events and large early release frequency was conducted. Based on the nature of the performance deficiency, it was expected that the 'A' SRV would have nominal reliability for all events that did not expose the valve to a harsh environment. The only external event that could present such conditions is a seismically induced LOCA. These events were determined to be substantially less than the contribution from the internal events of concern.

IMC 0609, "Containment Integrity SDP," was referenced and indicated that the dominant accident sequence was a candidate for a further review for risk contribution from a large early release. Additional technical information was obtained from NUREG/CR-7110, Vol. 1, Revision 1, "State-of-the-Art Reactor Consequence Analyses (SOARCA) Project Volume 1: Peach Bottom Integrated Analysis," since Pilgrim has a similar containment and the responses would be similar. Insights from NUREG/CR-7110, Vol. 1 indicate that the time to containment failure for severe accidents is much longer than previously understood. This, coupled with the dominant sequence which shows a successful HPCI run for a period of time, would further increase the time to containment failure. Although not quantified in this analysis, this would allow additional time to restore core cooling and prevent vessel failure. In addition to delayed radiological releases, the SOARCA study also demonstrates that the amount of radioactive material released is much smaller. Given this, the SRA qualitatively determined that the contributions from a large early release would not be a significant contribution. As a result, the performance deficiency was determined to be Green.

The inspectors determined there was no cross-cutting aspects associated with this finding since it was not representative of current Entergy performance. In accordance with IMC 0612, the causal factors associated with this finding occurred outside the nominal three-year period of consideration and were not considered representative of present performance.

<u>Enforcement</u>. Entergy's TS 5.4.1 states, in part, that written procedures recommended in Appendix A of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, February 1978, shall be established, implemented, and maintained. Section 9.b, "Procedures for Performing Maintenance," of Appendix A to Regulatory Guide 1.33 states that preventive maintenance schedules should be developed to specify, in part, the inspection of equipment and the replacement of parts that have a specific lifetime. Contrary to the above, from May 1993 to May 2017, Entergy's PM schedule for replacement of SRV solenoid coil and terminal board, rubber

O-rings, and valve seat inserts was inadequate. Specifically, the 'A' SRV solenoid coil was not replaced for 20 years, which exceeded the environmental qualified life and replacement frequency in the vendor manual and Entergy Preventive Maintenance Basis document. Entergy's immediate corrective actions included replacing the solenoid valves on all four SRVs. Entergy generated a CR to document this issue and initiated a root cause evaluation to understand the cause of the issue and to determine appropriate corrective actions to update PM schedules. Because this finding was of very low safety significance (Green) and has been entered into Entergy's CAP (CRs 2017-06183, 2017-05472, 2017-05386, and 2017-05829), this violation is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000293/ 2017003-03; Inadequate Preventive Maintenance Replacement Schedule for the SRVs' Solenoid Valve)**

2. Introduction. An NRC-identified Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified in that Entergy did not correct a condition adverse to quality when they replaced DPIS-2352, DPIS-1244, and DPIS-261 for the HPCI, reactor water cleanup, and low pressure core injection systems without upgrading their EQ status from the Division or Operating Reactors (DOR) Guidelines to 10 CFR 50.49 as required by 10 CFR 50.49(l).

   Description. Prior to issuance of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," licensees were required to meet the requirements of NUREG-0588, "Interim Staff Position on Equipment Qualifications of Safety-Related Electrical Equipment," and DOR Guidelines to meet General Design Criterion 4 (Environmental and Dynamic Effects Design Bases) of 10 CFR Part 50, Appendix A, as directed by the Commission in NRC Commission Order CLI 80-21 on May 23, 1980. When final rulemaking for 10 CFR 50.49 had been completed and the rule published on January 21, 1983, licensees who had previously qualified their existing equipment in accordance with the less stringent requirements of the DOR Guidelines or Category II of NUREG-0588 were not required to upgrade their equipment to the more stringent requirements of 10 CFR 50.49 or NUREG-0588, Category I. It was required of the licensees, however, that any replacement equipment be qualified in accordance with the provisions of 10 CFR 50.49 unless there were "sound reasons to the contrary," as per 10 CFR 50.49(l).

   While the rule does not provide specific guidance regarding "sound reasons to the contrary," NRC RG 1.89, Revision 1, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," and NUREG-0588 do provide guidelines for applying 10 CFR 50.49(l).
   Upgrading to the full requirements of 10 CFR 50.49 is important for replacement equipment as DOR Guidelines qualification programs were less stringent, and as such, did not require the effects of aging or synergistic effects to be accounted for during qualification testing. Upgrading to the full requirements of 10 CFR 50.49 provides a greater measure of assurance that electrical equipment in the scope of 10 CFR 50.49 will perform its specific safety function when called upon during a design basis accident.

   In 2012, Entergy initiated CR 2012-04248 when they discovered that ITT Barton DPISs, (DPIS-2352, DPIS-1244, and DPIS-261), were previously replaced (in November 2006) without upgrading their qualification status. The CR at that time identified that "sound reasons to the contrary do not exist." In 2013, Automated Engineering Services was tasked to perform a replacement study, AES-10373239-01 Revision 0, for the DPISs.

The study provided three viable upgrade options for replacement switches that would require various changes to the plant configuration, however, when the CR was closed in 2016, Entergy applied 10 CFR 50.49(l), after the fact, stating that no suitable replacement exists.

When the inspectors questioned the use of 10 CFR 50.49(l), Entergy provided more detail regarding their use of 10 CFR 50.49(l). Specifically, two potential replacement options would require minor modifications to racks and mounting and some decrease in the margin of the station's setpoint calculations, while the third would involve the addition of new bistables, cables, and power. Entergy contended that due to these factors, that NRC Regulatory Guide 1.89, paragraph C.6.d, "Replacement equipment qualified in accordance with the provisions of § 50.49 does not exist," and Regulatory Guide 1.89, paragraph C.6.f, "Replacement equipment qualified in accordance with § 50.49 would require significant plant modifications to accommodate its use," were sufficient sound reasons to not upgrade the replacement equipment.

The inspectors determined that Entergy was incorrect in their application of NRC Regulatory Guide 1.89 C.6.d because replacement equipment, as outlined and analyzed by the station and Automated Engineering Services for suitability, qualified in accordance with 10 CFR 50.49 did, in fact, exist to replace the old ITT Barton switches. Replacement equipment need not be "like-for-like" to be suitable. The inspectors determined that Entergy was similarly incorrect in their application of Regulatory Guide 1.89 C.6.f because, while some modifications would be required to accommodate non-"like-for-like" equipment, the modifications at least in two cases would not be considered "significant" as described. In one instance, only the addition of a new local gauge and a reduction of their setpoint margin would be required. The inspectors concluded that replacement equipment did exist and, therefore, use of the "sound reasons to the contrary" provision was not appropriate.

In response to the inspectors' questions, Entergy initiated CR 2017-06652 and CR 2017-09330. Engineering conducted an operability assessment and determined that since the replacement components were identical to the components removed, that there is no immediate operability issue. They further stated that the component testing frequency is current with satisfactory results, which maintains current operability. Entergy plans to perform a causal evaluation to determine their corrective actions necessary for meeting 10 CFR 50.49 EQ criteria for the affected components.

Analysis. The inspectors determined that Entergy's failure to upgrade the qualification of the replacement ITT Barton DPISs after identifying it as a condition adverse to quality, in accordance with Entergy's CAP procedure EN-LI-102, Revision 29, "Corrective Action Program," was a performance deficiency that was within Entergy's ability for foresee and correct. The replacement DPISs were within the scope of 10 CFR 50.49, but they were not upgraded/qualified in accordance with the provisions of 10 CFR 50.49 as required by 10 CFR 50.49(l). The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone 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 failure to use replacement equipment qualified in accordance with 10 CFR 50.49(l) adversely affects the reliability of the HPCI, reactor water cleanup, and low pressure core injection systems.

In accordance with IMC 0609.04, “Initial Characterization of Findings,” and Exhibit 2 of IMC 0609, Appendix A, “The SDP for Findings At-Power,” the inspectors determined the issue screened as having very low safety significance (Green) because the finding was a deficiency affecting the design or qualification of a mitigating SSC in which its operability or functionality was maintained. The inspectors determined that this finding had a cross-cutting aspect in Problem Identification and Resolution, Evaluation, because Entergy did not thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, Entergy did not properly evaluate a self-identified deficiency when they closed CR 2012-04248 without qualifying DPIS-2352, DPIS-1244, and DPIS-261 to the qualification requirements of 10 CFR 50.49. [P.2]

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requires in part, that, measures shall be established to assure that conditions adverse to quality, such as deviations and non-conformances are promptly identified and corrected. Contrary to the above, Entergy initiated CR 2012-04248 in September 2012, which identified a non-conformance with 10 CFR 50.49(l) since November 2006, however, they closed the CR on February 3, 2016, and did not adequately correct the condition adverse to quality. Specifically, Entergy’s resolution of CR 2012-04248 failed to qualify replacement switches DPIS-2352, DPIS-1244, and DPIS-261 in accordance with the provisions of 10 CFR 50.49. In response, Entergy conducted an operability assessment, which concluded that there were no immediate operability issues; and they will evaluate options for meeting 10 CFR 50.49 EQ criteria for the affected components. Because this finding was of very low safety significance (Green) and was entered into Entergy's CAP as CR 2017-06652 and CR 2017-09330, the NRC is treating this violation as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy, dated August 1, 2016, **(NCV 05000293/2017003-04, Failure to Correct Improper Environmental Qualification of Replacement Differential Pressure Indication Switches)**

3. Introduction. An NRC-identified Green NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was identified in that Entergy did not assure that the applicable design bases were correctly translated into specifications, drawings, procedures, and instructions; and did not verify the adequacy of design features by including suitable qualification testing of a prototype unit under the most adverse design conditions. Specifically, Entergy did not justify and document the activation energy (Ea) used to determine the thermal lifespan of silicon rubber gaskets used in MSIV limit switches.

   Description. The MSIV position indication switches are safety-related and are required to provide post-accident MSIV position indication to control room operators (full open, full closed, and partially closed). Namco (the switch vendor) had established an Ea for the silicon rubber gaskets and O-rings associated with the limit switch assembly to be 0.8 electron volts (eV) in the vendor manual and qualification test report, QTR-140. Ea is a material characteristic that is a measure of sensitivity to thermal aging (i.e., it relates the rate of aging process to temperature); and typically, the lower the Ea, the shorter the qualified life of the component being evaluated. Namco subsequently provided additional information to update the Ea of only the O-rings to 1.31 eV. However, Entergy updated the Arrhenius calculation, which establishes the component service life, for both the O-ring and silicon rubber gasket from 0.8 eV to 1.31 eV in May 2007. With an Ea of 1.31 eV, the silicon rubber and O-rings were no longer the most limiting components in the limit switch assembly (i.e., their individual expected service life was extended and were no longer limiting values for the entire limit switch assembly). The contact block with an Ea of 0.836 eV became the next most limiting component, yielding an overall qualified life of 16.7 years for the limit switch assembly; and associated PM replacement frequency of 16.7 years for the limit switch assembly.

Entergy's EQ documentation stated that 0.8 eV for silicon rubber gaskets was a very conservative value and that a test report performed by an independent consultant, EGS Corporation, determined that Ea for silicon rubber in the nuclear industry ranged from 0.98 eV to 2.0 eV. Accordingly, Entergy elected to select a more realistic value. However, they selected a value of 1.31 eV for the silicon rubber gasket but did not provide a supporting technical basis. While there is a range of Ea values for specific generic materials, the actual chemical composition and material properties vary based on specific manufacturing and production, necessitating specific testing/analysis to determine the proper Ea associated with the as-manufactured component. The original Ea value of 0.8 eV, identified in the vendor manual and vendor EQ test report yielded a qualified life of the silicon rubber gaskets as 13.5 years, less than the current 16.7 year qualified life of the assembly. The inspectors concluded that, absent an adequate technical basis for the 1.31 eV value, the qualified life of 16.7 years is not conservative. In response to this issue, Entergy's corrective actions included performing an immediate determination of operability, in which Entergy concluded that the affected components are operable for the current operating cycle. Specifically, the service time of the installed MSIV limit switch assemblies, to the end of the current operating cycle, is less than the currently supported qualified life of 13.5 years. They also plan to perform a causal evaluation to determine their corrective actions to properly identify, document and justify the proper Ea for the silicon rubber gasket. Entergy documented this issue in CR 2017-09241.

<u>Analysis</u>. The inspectors determined that Entergy's failure to verify, justify, and document the basis for the Ea used to establish the MSIV limit switch silicon rubber gasket qualified service life, as specified by NRC RG 1.89, was a performance deficiency that was reasonably within Entergy's ability to foresee and correct. Specifically, Entergy used an Ea that was less conservative than the previously existing value, but did not provide an adequate technical basis for their selection.

This performance deficiency was more than minor because if left uncorrected, it could have had the potential to lead to a more significant safety concern. Specifically, without using an adequate Ea, the MSIV limit switch assemblies could have been allowed to exceed their qualified life. Also, the finding was associated with the Design Control attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of ensuring that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, using an incorrect Ea provided a non-conservative qualified service life value for the MSIV position indicating limit switches, and the MSIV limit switch assemblies would have exceeded their qualified life if left uncorrected. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 3 of IMC 0609, Appendix A, "The SDP for Findings At-Power," the inspectors determined the issue screened as having very low safety significance (Green) because it was a design deficiency confirmed not to result in an actual open pathway in the physical integrity of reactor containment (valves, airlocks, etc.), containment isolation system (logic and instrumentation), and heat removal components; and did not involve an actual reduction in function of hydrogen igniters in the reactor containment. This finding was not assigned a cross-cutting aspect because the performance deficiency did not reflect current licensee performance.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. It also requires that where a test program is used to verify the adequacy of design features, it shall include suitable qualification testing of a prototype unit under the most adverse design conditions. Contrary to the above, from May 2007 to the present, Entergy’s design control measures did not provide for verifying or checking the adequacy of design of the MSIV position indication limit switch assembly. Specifically, Entergy did not verify or check the adequacy of the Ea for silicon rubber gaskets before using the newly calculated Ea in ongoing qualifications. In response, Entergy performed an immediate determination of operability, and they plan to properly identify, document, and justify the proper Ea for the silicon rubber gasket. Because this finding was of very low safety significance (Green) and was entered into Entergy's CAP as CR 2017-09241, the NRC is treating this violation as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy, dated August 1, 2016. **(NCV 05000293/2017003-05, Failure to Verify, Justify, and Document Activation Energy for Main Steam Isolation Valve Position Indicator Switch Assembly Components)**

.2 (Closed) Licensee Event Report (LER) 05000293/2016-010-00 and 2016-010-01: MSIV Inoperability Led to a Condition Prohibited by the Plants Technical Specifications

On December 15, 2016, and April 17, 2017, Entergy identified leaks on the ‘C’ and ‘D’ main steam lines. A body-to-bonnet steam leak was identified on the 2D MSIV and a packing leak was identified on the 2C MSIV, which rendered the MSIVs inoperable for a time greater than that allowed by TS 3.7.A.2.b, “Primary Containment Isolation Valves.” Entergy determined that TS 3.7.A.2.b requires that, in the event any automatic primary containment isolation valve becomes inoperable, at least one containment isolation valve in each line shall be deactivated in the isolated condition, or TS 3.7.A.5, “Primary Containment,” applies, which states an orderly shutdown shall be initiated and the reactor shall be placed in cold shutdown. Entergy shut down the unit to repair the 2C and 2D MSIVs in December 2016. On April 15, 2017, LLRT identified that both the 1C and 1D MSIVs failed the test, with the 1C MSIV leak rate exceeding the capacity of the leak rate equipment. Entergy repaired the 1D, 1C, and 2C MSIVs and performed partial repacks of the other five MSIVs to address the leakage concerns. The inspectors reviewed the LER, CRs, causal evaluation, and corrective actions. One self-revealed violation that was characterized as more than minor was identified and is documented below. This LER is closed.

Introduction. A self-revealed Green NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” and TS 4.7.A.2.a.3.2 and TS 4.7.A.2.a.3.4, “Primary Containment-Primary Containment Integrity,” was identified because Entergy did not implement a vendor recommended modification to address MSIV stem damage caused by an unstabilized main poppet. As a result, the 1C and 1D MSIVs experienced damage that was identified during the failure of LLRT of the valves.

Description. On April 15, 2017, as-found LLRT, required by 10 CFR Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,” identified that the 1C and 1D MSIVs exceeded the TS values. TS 4.7.A.2.a.3.1 contains criteria that the primary containment overall leakage rate is less than or equal to 1.0 L_a. L_a is the maximum allowable test leak rate which is 1.0 percent per day at a pressure of 45 psig. L_a, for Pilgrim is 210.50 standard liters per minute (SLM). TS 4.7.A.2.a.3.4

requires that the combined main steam line leakage rate is less than or equal to 46 standard cubic feet per hour (SCFH), which is equivalent to 21.71 SLM. On April 15, 2017, the LLRT as-found leakage was 25.8 SLM for the 1D MSIV and reached the capacity of the leak rate monitor for the 1C MSIV, which is 101 SLM. While not directly exceeding the TS value, the 2C MSIV was also required to be overhauled due to a LLRT as-found value of 12.3 SLM, which if left uncorrected, would have exceeded the combined main steam line leakage allowance of 21.71 SLM.

Entergy entered the Appendix J failures into the CAP as CR 2017-5075 and performed a root cause evaluation. Entergy identified that flow-induced vibration was a contributing factor in the failure of all three LLRTs. The root cause evaluation, CR 2017-5075, discusses operating experience available to the site from GE SIL 568, “MSIV Guide Rib Wear,” Atwood and Morrill Technical Bulletin 27.0, “Mitigation of the Potential for Stem Failures in Wye Globe Main Steam Isolation Valves,” and internal and external operating experience notices. The vendor recommended in GE SIL 568, dated August 10, 1993, that sites implement a main poppet stabilization modification to address the flow-induced vibration. The modification utilizes a new main poppet and valve bonnet to stabilize the main poppet tightly against the bonnet when the valve is open. This modification is implemented to address flow induced vibratory fatigue on the stem from oscillations caused by flow lifting the poppet. Entergy previously determined this modification was not required based on the relatively small MSIVs installed at Pilgrim. In 2015, the 1D MSIV was overhauled due to the failure of a main poppet anti-rotation device that is connected to the valve stem. At that time, minor wear was observed on one of the guide ribs, but remained within the allowed procedural tolerance. Entergy reasonably had an opportunity to identify the cause of the rib damage in 2015 that led to the 2017 LLRT failures.

The inspectors determined that not implementing the vendor recommended modification contributed to the 1C and 1D MSIVs exceeding TS values of 210.5 SLM and 21.71 SLM. In this case, the ‘C’ and ‘D’ main steam lines were inoperable from the last known LLRT in May 2015 until the repairs in May 2017. In addition, inspectors reviewed data from repairs made to the 2C and 2D MSIVs in December 2016. Inspectors determined that during the post-maintenance testing, the line was pressurized to 23 psig between the inboard and outboard MSIVs of both lines. While the testing is not credited for LLRT, it did establish that the 1C MSIV did not exhibit the gross failure seen in April 2017 while the outboard 2C MSIV experienced a packing leak. Similar testing was performed on the ‘D’ main steam line at the same time to test the seal weld repair on the 2D MSIV. Entergy also performed a calculation to determine the maximum leakage through the MSIV packing stuffing box with no packing to address concerns about total leakage. Entergy concluded, the total possible leakage was 5400 SCFH. Actual plant conditions indicated a less severe packing leak on 2C MSIV. Entergy concluded the failure of the LLRTs on the ‘C’ and ‘D’ main steam lines did not provide an open pathway from containment. The inspectors reviewed Entergy’s conclusion and agreed with the determination.

Entergy determined that if the valves were to remain in service for additional cycles, the main poppet stabilization modification would be necessary. Entergy implemented compensatory measures until the permanent modification can be made. The compensatory measures included performing an improved packing strategy for all eight MSIVs during the 2017 RFO to improve leak tightness of the valves, and providing procedural guidance to close one MSIV when operating at low powers for greater than 24 hours. The inspectors reviewed the compensatory measures and since the degradation mechanism is a long term concern, the inspectors determined the compensatory measures were adequate until the permanent modification could be made.

Analysis. The inspectors determined that Entergy did not implement a vendor recommended modification to the MSIVs that resulted in failed LLRTs that exceeded TS values for the 1C and 1D MSIVs. This was a performance deficiency that was reasonably within Entergy's ability to foresee and correct and should have been prevented. The performance deficiency was more than minor because it is associated with the SSC and Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events. Specifically, Entergy did not implement GE SIL 568 to address MSIV damage due to an unstabilized main poppet. This damage was observed in three MSIVs during the 2017 RFO.

In accordance with IMC 0609.04, "Initial Characterization of Findings," Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," issued June 19, 2012, the inspectors determined that the finding was of very low safety significance (Green) because the performance deficiency did not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, or heat removal components, or a reduction in function of hydrogen igniters in the reactor containment. The finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because Entergy did not evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, Entergy identified in 2015 that damage was occurring in the 1D MSIV, and the evaluation did not identify actions to address the vendor modification to correct the underlying issue. [P.2]

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of SSCs to which Appendix B applies (i.e. that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public). Contrary to the above, between approximately 1993 and the present, Entergy had not implemented a vendor recommended modification to safety-related MSIVs based on industry operating experience. Specifically, the vendor provided a modification due to damage observed from flow induced vibration on MSIVs, and Entergy did not implement the modification, which ultimately allowed several MSIVs to become damaged and led to the failure of the associated LLRTs.

TS 4.7.A.2.a.3.1, "Primary Containment- Primary Containment Integrity," requires, that primary containment overall leakage rate is less than or equal to 1.0 L_a. TS 4.7.A.2.a.3.4, "Primary Containment- Primary Containment Integrity," requires, in part, that the leakage rate acceptance criteria for combined main steam line leakage rate is less than or equal to 46 SCFH at 23 psig. TS 3.7.A.2, "Primary Containment- Primary Containment Integrity," requires, in part, that primary containment integrity shall be maintained at all times when the reactor is critical or an orderly shutdown shall be initiated and the reactor shall be in cold shutdown condition within 24 hours. Contrary to the above, between May 20, 2015 and April 10, 2017, the primary containment overall leakage rate exceeded 1.0 L_a, and the leakage rate acceptance criteria for combined main steam line leakage exceeded 46 SCFH at 23 psig, which resulted in primary containment being inoperable. Primary containment integrity was not maintained at all times when the reactor was critical and the unit was not placed in cold shutdown condition within 24 hours.

Entergy's corrective actions included overhauling the valves, adjusting packing on all eight MSIVs, and providing procedural guidance for closing a MSIV during low power operations. Because this violation was of very low safety significance (Green) and entered into Entergy's CAP as CR 2017-5075, this violation is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. (**NCV 05000293/ 2017003-06, MSIVs Fail Local Leak Rate Test and Exceed La**)

.3 (Closed) LER 05000293/2017-010-00: Air Accumulation Creates Small Void in Core Spray Discharge Piping

On June 6, 2017, Entergy personnel were performing UT examinations on 'A' CS high point piping to ensure the piping was water solid when they identified that the top of the horizontal pipe had an internal air void. Specifically, the top 2 inches of the 10-inch CS pump discharge line had accumulated an air void within the known inverted loop in the CS 'A' discharge line, presumably resulting from being drained for maintenance during the RFO. Upon discovery of the void, TS 3.5.A, "Core Spray and LPCI Systems," was entered and the void was filled immediately to correct the issue. TS 3.5.H, "Maintenance of Filled Discharge Pipe," requires, in part, that whenever CS systems are required to be operable, the discharge piping from the pump discharge to the last block valve shall be filled. In this case, the 'A' CS pump discharge line was not filled to the last block valve, which exceeded the seven day allowed outage time of TS 3.5.A and the unit was not placed in cold shutdown. The inspectors reviewed the LER, CRs, causal evaluation, and corrective actions. One self-revealed violation that was characterized as more than minor was identified and is documented below. This LER is closed.

Introduction. A self-revealed Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," and TS 3.5.A, "Core Spray and LPCI Systems," was identified when Entergy did not appropriately establish procedures for filling and venting the 'A' CS system. As a result, the system was returned to service on May 21, 2017, with a void in the CS 'A' system, which rendered it inoperable. The 'A' CS system was inoperable until Entergy filled and vented the system on June 7, 2017, which exceeded the TS allowed outage time.

Description. On June 7, 2017, PNPS personnel performed planned UT examinations on the 'A' CS system and identified a void in the top 2 inches of a 10-inch diameter horizontal high point pipe, resulting in the 'A' CS system being declared inoperable. This section of pipe is 36 feet long and is an inverted loop, where the discharge line in the torus compartment drops in elevation before going up to the containment penetration, resulting in a local high point. The UT was a planned, routine test following the RFO that ended on May 21, 2017.

On April 27, 2017, the 'A' CS system was removed from service under tagout 14-007-D-MO-1400-4A and drained to support planned system repairs and maintenance. Following completion of the work, the system was returned to service on April 30, 2017, by removing the tagout. The restoration section of the tagout directed operators to review PNPS 2.2.20, “Core Spray,” Attachment 8, which contained specific guidance detailing the dynamic venting process utilized for flushing this specific section of piping and displacing any potential gas voids. PNPS 2.2.20 does not, however, contain stand-alone guidance for full system filling and venting. Because of this, the licensee decided to develop a fill and vent plan for the ‘A’ CS system using generic guidance from PNPS 2.1.11.1, “System Fill, Vent and Drain Instructions.” PNPS 2.1.11.1, however, lacked the necessary details for adequately filling and venting the ‘A’ CS inverted loop piping, and the licensee did not implement the specific guidance in PNPS 2.2.20, Attachment 8. As a result, air that had entered the system during the April 27-30, 2017, maintenance window was not appropriately vented and remained trapped in the system.

PNPS performs UT inspections at the end of each RFO to ensure that voiding in the emergency core cooling system does not impact operability. The UT inspections ensure that the piping is water solid, thus preventing damage from potential water hammer events. Pilgrim TS 3.5.H, “Maintenance of Filled Discharge Pipe,” requires that the piping from the CS pump discharge to the last block valve be filled. When the RFO ended on May 21, 2017, Entergy did not perform the UT inspections ensuring operability until June 7, 2017, which exceeded the CS limiting condition for operation allowed outage time, and would have required a shutdown. The immediate corrective actions taken by Entergy on June 7, 2017, included venting the air from the inverted loop, performing a follow-up UT examination to ensure the piping was full, and declaring the system operable.

Although the ‘A’ CS system was inoperable, Entergy performed an evaluation and determined the ‘A’ CS system as found void volume did not exceed the maximum allowable void criteria, and was still available to perform its specified safety functions. The inspectors reviewed the evaluation and agreed with the determination.

The inspectors determined that both the procedure used to fill and vent the ‘A’ CS system and the timeframe in which Entergy chose to perform the UT examinations were inadequate. Entergy should have performed the UT examinations in a timely manner to ensure operability prior to exceeding the seven day limiting condition for operation limit. Additionally, the UT examinations are required following only RFOs, not following major system outages or operation, two potential sources of gas entrapment.

<u>Analysis</u>. The inspectors determined that Entergy’s vent and fill plan for the ‘A’ CS system did not adequately incorporate the guidance of PNPS 2.2.20 to ensure the inverted loop in the discharge piping was filled before the system was required to be operable on May 21, 2017, and that this constituted a performance deficiency that was reasonably within the licensee’s ability to foresee and correct and should have been prevented. The performance deficiency was more than minor because it is associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, Entergy returned the ‘A’ CS system to service with a void in the discharge piping that made the pump inoperable, and the UT to verify the piping was full was not completed in a timely manner to ensure ‘A’ CS was operable when required in the Hot Shutdown, Startup, and Run modes.

In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The SDP for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not affect the design or qualification of a mitigating SSC and the finding did not represent a loss of system or function. This finding had a cross-cutting aspect in the area of Human Performance, Avoid Complacency, because individuals in the organization did not recognize and plan for the possibility of mistakes, latent issues and inherent risk, even while expecting successful outcomes. Specifically, Entergy's plan to fill and vent the 'A' CS system failed to review and implement the requirements of PNPS 2.2.20 for dynamically venting the inverted loop in 'A' CS discharge piping in accordance with the restoration instructions in the tagout. [H.12]

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, from April 30, 2017, to June 7, 2017, Entergy did not appropriately prescribe instructions or procedures for maintenance associated with the 'A' CS system. Specifically, appropriate instructions for filling and venting an inverted loop were not incorporated into the maintenance plan developed under PNPS 2.1.11.1, which resulted in a void in the inverted loop and the 'A' CS system being inoperable. The plan also did not ensure the UT was performed prior to the 'A' CS system being required.

TS 3.5.A.1 requires that both CS systems shall be operable during Run, Startup, and Hot Shutdown Modes and prior to reactor startup from Cold Shutdown. TS 3.5.A.2 requires that, while in Run, Startup, and Hot Shutdown Modes, with one of the CS systems inoperable, Entergy must restore the inoperable CS system to operable status within seven days and maintain all active components of the LPCI system and diesel generators operable. Otherwise, Entergy must place the unit in at least Cold Shutdown within 24 hours. Contrary to the above, with the unit in Hot Shutdown, Startup, and Run Modes beginning on May 21, 2017, Entergy did not enter TS 3.5.A when a two-inch void in the 'A' CS system rendered it inoperable. On May 28, 2017, Entergy did not restore the CS system to operable status within seven days in accordance with TS 3.5.A.2. On May 29, 2017, Entergy was not in at least Cold Shutdown within 24 hours. Entergy identified the void on June 7, 2017 by conducting routine, post outage UT on the 'A' CS piping.

Entergy's corrective actions include immediately filling and venting the line, plans to revise procedural requirements for CS filling and venting, and providing a briefing to licensed operators on this event, its causes, and corrective actions. Entergy performed additional UT later on June 7, 2017, to verify the system was adequately filled. Because this violation was of very low safety significance (Green) and was entered into Entergy's CAP as CR 2017-6029, the NRC is treating this as an NCV in accordance with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000293/2017003-07, Core Spray Voiding Due to Inadequate Instructions)**

.4 (Closed) LER 05000293/2017-003-00: Pressure Suppression Pool Declared Inoperable Due to High Water Level

On March 31, 2017, with the reactor at 97 percent core thermal power and steady state conditions, operators caused water level to increase in the pressure suppression pool. Operators incorrectly restored a CS system valve line-up after a planned maintenance activity that resulted in water draining by gravity from the condensate storage tank to the suppression pool. The rise in suppression pool water level exceeded the maximum water level specified in TSs. The differential pressure limit between the drywell and pressure suppression pool was also not met. Entergy submitted LER 05000293/2017-003-00, "Pressure Suppression Pool Declared Inoperable Due to High Water Level," on May 25, 2017. The enforcement aspects of this issue are discussed in Section 4OA2.1 of NRC Integrated Inspection Report 05000293/2017002. The inspectors did not identify any new issues during the review of the LER. This LER is closed.

4OA5 Other Activities

Industry's Implementation of the Groundwater Protection Initiative

Entergy did not meet one acceptance criteria for Objective 3.0 of the NEI 07-07 GPI, which states, "Perform program oversight to ensure effective implementation of the GPI program." Specifically, acceptance criteria 3.2.b was not met since no documentation exists to demonstrate that a periodic review of the GPI was performed every five years subsequent to the initial NEI GPI Peer Assessment that was performed on February 8, 2010. Additionally, Entergy's Fleet Procedure EN-CY-111, "Radiological Groundwater Monitoring Program," Revision 7, step 5.17 [1] states that a periodic review of the Radiological Groundwater Monitoring Program should be performed every five years. In accordance with IMC 0612, "Power Reactor Inspection Reports," this performance deficiency was determined to be minor because it did not adversely affect the Public Radiation Safety Cornerstone objective. NRC Inspectors independently concluded that the Groundwater Protection Program was adequately implemented at Pilgrim. Entergy's chemistry personnel entered this issue into the CAP as CR 2017-09417 and developed a corrective action to complete the NEI GPI Peer Assessment by December 30, 2017.

4OA6 Meetings, Including Exit

On October 18, 2017, the inspectors presented the inspection results to Mr. Brian Sullivan, Site Vice President, and other members of the Entergy staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

B. Sullivan, Site Vice President
R. Pitts, General Plant Manager
P. Beabout, Security Manager
G. Blankenbiller, Chemistry Manager
D. Calabrese, EP Manager
B. Chenard, Operations Manager
N. Eisenmann, Supervisor
G. Flynn, Engineering Director
J. Gerety, Recovery Manager
P. Harizi, Senior Design Engineer
R. Ho, Programs Engineer
M. Jacobs. Nuclear Oversight Manager
J. Keene, Design Electrical / I&C Supervisor
J. Kritzer, Senior Reactor Operator
D. Labun, System Engineering
P. Leavitt, Chemistry Supervisor
C. Littleton – Risk Analyst
F. McGinnis, Flex Fire Marshall
P. Miner, Regulatory Assurance Engineer
D. Noyes, Recovery Director
K. O’Brien, Electrical Relay Technician
C. Perkins, Regulatory Assurance Manager
M. Powers, Licensing Specialist
B. Rancourt, Senior Engineer
N. Reece, Mechanical System Engineer
M. Romeo, Regulatory Assurance & Performance Improvement Director
T. White, Design Engineering Manager
K. Whippie, VY Chemistry Manager
M. Williams, Licensing Engineer
A. Zelie, Radiation Protection Manager

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

05000293/2017003-01	NCV	Inadequate Procedure for Loss of Control Room Air Conditioning (Section 1R12)
05000293/2017003-02	NCV	HPCI Turbine Exhaust Check Valve Failures Exceed Primary Containment Leakage Limit (Section 4OA2.2)
05000293/2017003-03	NCV	Inadequate Preventive Maintenance Replacement Schedule for SRVs Solenoid Valve (Section 4OA3.1.b.1)

05000293/2017003-04	NCV	Failure to Correct Improper Environmental Qualification of Replacement Differential Pressure Indication Switches (Section 4OA3.1.b.2)
05000293/2017003-05	NCV	Failure to Verify, Justify, and Document Activation Energy for Main Steam Isolation Valve Position Indicator Switch Assembly Components (Section 4OA3.1.b.3)
05000293/2017003-06	NCV	MSIVs Fail Local Leak Rate Test and Exceed La (Section 4OA3.2)
05000293/2017003-07	NCV	Core Spray Voiding Due to Inadequate Instructions (Section 4OA3.3)

Closed

05000293/2017001-01	URI	Concern Regarding Ability to Declare EALs During Loss of Control Room Air Conditioning (Section 1R12)
05000293/2016-010-00 and 2016-010-01	LER	MSIV Inoperability Led to a Condition Prohibited by the Plants Technical Specification (Section 4OA3.2)
05000293/2017-003-00	LER	Pressure Suppression Pool Declared Inoperable Due to High Water Level (Section 4OA3.4)
05000293/2017-010-00	LER	Air Accumulation Creates Small Void in Core Spray Discharge Piping (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Procedures
2.2.19, Residual Heat Removal, Revision 113
2.2.20, Core Spray, Revision 88
2.2.22, Reactor Core Isolation Cooling System, Revision 81
2.2.32, Salt Service Water, Revision 96
2.2.108, Diesel Generator Cooling and Ventilation System, Revision 48
7.8.1, Chemistry Sample and Analysis Program, Revision 77
8.2-2.10.1-3, Logic System Functional Test – Core Spray System ‘B’ Drywell High Pressure Auto-Initiation Trip, Revision 25
8.9.1, Emergency Diesel Generator and Associated Emergency Bus Surveillance, Revision 141
8.E.29.1, Salt Service Water Instrument Calibration and Functional Test, Revision 21

Condition Reports
2017-8839 2017-8848

Miscellaneous
V0454, Emergency Diesel Generators Instruction Manual, Revision 82
V1186, OPW Over Spill Containment and Overfill Prevention Equipment, Revision 2

Drawings
C-64-1-1, Underground Storage Tanks T-126A & B and T-129A & B, Revision 7
House Drawing: 345 kV Distribution, Revision 0
House Drawing: Emergency Diesel Generator Output Breaker Logic, Revision 0
House Drawing: Emergency Diesel Generator Sheet 1 and 2, Revision 0
M212, SH1, P&ID Service Water System, Revision 96
M219, P&ID Diesel Generator Air Start System, Revision 24
M223, P&ID Diesel Oil Storage and Transfer System, Revision 34
M242, Core Spray System, Revision 16
M245, PI&D RCIC system. Revision 40
M247 PI&D, Reactor Water Cleanup, Revision 55
M252, SH2, PI&D Nuclear Boiler, Revision 70
M259, P&ID Diesel Generator Turbo Air Assist System, Revision 10

Section 1R05: Fire Protection

Procedures
5.5.2, Special Fire Procedure, Revision 56
89XM-1-ER-Q, Updated Fire Hazards Analysis, Revision 16

Condition Reports
2017-5644 2017-7257 2017-7424

Miscellaneous
89XM1ERQ, Updated Fire Hazard Analysis, Revisions 5 & 16
Fire Hazards Analysis –Fire Zone 1.8, Fire Zone 1.3, and Fire Zone 1.23 RCIC

Section 1R11: Licensed Operator Requalification Program

Procedures
3.M.4-107, RCIC Turbine Overspeed Preventive Maintenance, Revision 11
EN-OP-115, Conduct of Operations, Revision 21
2.2.22, Reactor Core Isolation Cooling System, Revision 81

Section 1R12: Maintenance Effectiveness

Procedures
2.4.149, Loss of Control Room Air Conditioning, Revisions 15 through 20
EN-DC-203, Maintenance Rule Program, Revision 3
EN-DC-204, Maintenance Rule Scope and Basis, Revision 3
EN-DC-205, Maintenance Rule Monitoring, Revision 6
EN-DC-206, Maintenance Rule (a)(1) Process, Revision 3
TP17-007, QP-9.9 General Welding Requirements, Revision 0
TP17-008, QP-9.10 Control of Weld and Base Metal Repairs, Revision 0

Condition Reports
2009-4634 2015-6612 2015-7841 2015-9395 2016-0281 2016-0385

2016-1132	2016-2198	2016-2527	2016-3129	2016-6379	2016-7179
2016-7184	2016-7195	2016-8059	2016-8600	2016-8605	2016-8657
2016-8663	2016-8715	2016-8725	2016-8769	2016-9803	2017-0235
2017-0242	2017-1518	2017-1619	2017-2622	2017-3110	2017-4047
2017-4048	2017-4136	2017-4256	2017-4256	2016-7421	2017-4794
2017-4826	2017-5075	2017-5082	2017-5089	2017-5094	2017-5542
2017-5627	2017-6219	2017-6596	2017-6644	2017-7998	2017-8030
2017-8073					

Maintenance Orders/Work Orders

0422681	0441769	0468384	0478901	0482245

Miscellaneous
1N1-297, Control Room Heat Loads, Revision 4
EC 65239, 71853
EN-DC-126, Control Room and Cable Spreading Room Heatup Calculations, Revision 6
EP-AD-270, Equipment Important to Emergency Response (EITER), Revision 3
FSAR
Maintenance Rule (a)(1) Action Plan, K-117 Air Compressor Engine Oil Level Trips, dated 7/26/17
Maintenance Rule Basis Document – System 31 Instrument Air, Revision 5
MRBD23, High Pressure Coolant Injection System, Revision 5
NUMARC 93-01, Industry Guideline For Monitoring The Effectiveness Of Maintenance At Nuclear Power Plants, Revision 4A
PNPS RPT-05-006, Pilgrim Nuclear Power Station Mitigating System Performance Index (MSPI) Basis Document, Revision 5
PNPS System Health Report 29, Salt Service Water
PNPS 10 CFR 50.65 Maintenance Rule Scoping Basis Document for Salt Service Water, Revision 4
TDBD-110, Design Basis Document for Control Room Habitability, Revision 1
V0303, Byron Jackson Pumps, Revision 38

Drawings
M-212 Sheet 1, Service Water System, Revision 96

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
1.3.142, PNPS Risk Review and Disposition, Revision 7
1.5.22, Risk Assessment Process, Revision 27
8.C.34, Operations Technical Specifications Requirements for Inoperable Systems/ Components, Revision 64
EN-OP-119, Protected Equipment Postings, Revision 8
EN-WM-104, Online Risk Assessment, Revisions 14 and 15

Condition Reports
2017-2133 2017-4494

Miscellaneous
EOOS Risk Evaluation dated July 11, 2017

EOOS Risk Profile dated August 14, 2017
Station Risk Assessments for July 24 through 26, 2017

Drawings
M219, P&ID Diesel Generator Air Start System, Revision 24
M223, P&ID Diesel Oil Storage and Transfer System, Revision 34

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
2.2.8, Standby AC Power, Revision 118
2.2.32, Salt Service Water System, Revision 96
2.2.21.5, HPCI Injection and Pressure Control, Revision 18
2.4.A.23, Loss/Degradation of 23 kV line, Revision 26
3.M.4-10, Valve Maintenance, Revision 46
EN-MA-118, Foreign Material Exclusion, Revision 10
EN-OP-104, Operability Determination Process, Revision 11

Condition Reports

2014-1987	2015-3151	2017-4941	2017-6213	2017-6965	2017-6995
2017-7083	2017-7298	2017-7320	2017-7428	2017-8044	2017-8057

Maintenance Orders/Work Orders
00473404

Miscellaneous
Engineering Evaluation 00-022, Differential Pressure Across RBCCW Heat Exchangers above Acceptance Criteria in Procedure 8.5.3.14, dated May 10, 2000
SDBD-61, Emergency Diesel Generator and Auxiliary Systems, Revision 2
Trending Data for EDG Jacket Water Heat Exchangers Temperatures taken over last two years
V0391, Anchor/Darling Company Maintenance Manual for Swing Check Valves, Revision 8

Drawings
M132, BC11-13, 20”-150# Swing Check Valve-Bolt Bonnet-Cast Carbon Steel Stellite Trim-Butt Weld Ends, Revision E2
M272, P&ID Emergency Diesel Generator Jacket Water Cooling System, Revision 9

Section 1R18: Plant Modifications

Miscellaneous
R2079-07-001, Assessment of Potential Multiple Spurious Operations Impacts in III.G.2 Fire Area, Revision 1

Drawings
E7, 4160 Volt System, Revision 29

Section 1R19: Post-Maintenance Testing

Procedures
3.M.3-17.1, Raychem Or Taping Of 1000 Volt And Under Cables and/or Wires, Revision 26
3.M.3-51, Electrical Termination Procedure, Revision 31

3.M.4-14.2, Salt Service Water Pumps: Routine Maintenance, Revision 69
8.5.3.2.1, Salt Service Water Pump Quarterly and Biennial (Comprehensive) Operability And Valve Operability Tests, Revision 34
8.9.1, Emergency Diesel Generator and Associated Emergency Bus Surveillance, Revisions 140 and 141
8.E.3, Control Rod Accumulator's Operability, Revision 28
8.M.2-2.10.8.5, Diesel Generator 'A' Initiation by Loss of Offsite Power Logic- Critical Maintenance, Revision 60
8.M.3-18, Standby Gas Treatment System Exhaust Fan Logic Test and Instrument Calibration, Revision 53
EN-WM-107, Post-Maintenance Testing, Revision 5
EN-MA-125, Trouble Shooting Control of Maintenance Activities, Revision 20

Condition Reports

2017-6866	2017-7110	2017-7380	2017-7477	2017-7491	2017-7532
2017-7533	2017-8078	2017-8365	2017-8581	2017-8590	2017-8626
2017-8636	2017-8689				

Maintenance Orders/Work Orders

00040511	00462502	00479892	00480341	00482380	52577508
52618015	52775715				

Miscellaneous
EC 73272
SEP-PNPS-IST-009, Administrative Guidelines for the Inservice Testing and Appendix B Testing Programs, Revision 2
FSAR Section 7.18

Drawings
E241, Stand-by Gas Treatment, Revision 14

Section 1R22: Surveillance Testing

Procedures
2.2.22, Reactor Core Isolation Cooling System, Revision 81
3.M.3-1, A5/A6 Buses 4kV Protective Relay Calibration/Functional Test and Annunciator Verification, Revision 148
3.M.3-61.14, Emergency Generator Performance Data Monitoring, Revision 3
8.5.4.1, High Pressure Coolant Injection System Pump and Valve Quarterly and Biennial Comprehensive Operability, Revision 123
8.9.1, Emergency Diesel Generator and Associated Emergency Bus Surveillance, Revision 143
8.F.38.1, Diesel Generator Instrument Calibration and Functional Test, Revision 47
8.M.2-2.10.8.5, Diesel Generator 'A' Initiation by Loss of Offsite Power Logic Test, Attachment 1, Revision 60
ARP-C7L-C4, Alarm Response Procedure, Revision 19
NE3.20, Preparation, Review, Approval, Revision, and Closeout of Modifications at Pilgrim Station, Revision 23

Condition Reports

2017-6197	2017-7898	2017-7998	2017-8030	2017-8365	2017-8369
2017-8376	2017-8376	2017-9152	2017-9290		

Maintenance Orders/Work Orders
00484688 15678202 52616628 52760289

Miscellaneous
EC 73704
MPR Associates Input to Pilgrim's EDG Operability

Drawings
ES-200, SH 1, 4160 Volt Switchgear Relay Settings, Revision 20
ES-200, SH 2, 4160 Volt Switchgear Relay Settings, Revision 18
ES-200, SH 3, 4160 Volt Switchgear Relay Settings, Revision 13
M243, P&ID HPCI System, Revision 55
M6-22-14 SH1, Diesel Generator "A" X107A Engine Control, Revision 39

Section 2RS6: Radioactive Gaseous and Liquid Effluent Treatment

Procedures
7.1.142, Groundwater and Precipitation Radioactivity Sampling, Revision 2
7.1.30, HEPA Filter and Charcoal Cell Performance Test Program, Revision 34
7.1.44, Sampling of Charcoal Cells in Standby Gas Treatment and Control Room Environmental Filters' Systems for Methyl Iodide Testing, Revision 24
7.1.83, Sampling Closed Cooling Water Systems and Station Heat System, Revision 19
7.1.89, Sewage Treatment Plant Sampling, Revision 7
7.3.25, Particulate and Iodine Monitoring at the Main Stack and the Reactor Building Vent, Revision 44
7.3.31, Tritium Sampling, Revision 26
7.3.36, Offgas Sampling and Analysis, Revision 63
7.3.41, Salt Service Water Sampling and Analyses, Revision 38
7.3.48, Airborne Effluent Monitoring of the Turbine Deck and Reactor Feed Pump Bay, Revision 28
7.3.51, Airborne Effluent Monitoring of the Station Services Red Line Facility and Miscellaneous Sample Points, Revision 11
7.4.12, Calibration of the SJAE Offgas Process Radiation Monitors, Revision 32
7.4.29, Source Calibration of General Atomic High Range Noble Gas Monitor, Revision 29
7.4.48, Calibration of Turbine Building Gaseous Effluent Monitors (GEMS), Revision 10
7.4.49, Operation of Turbine Building Gaseous Effluent Monitors (GEMS), Revision 14
7.4.60, Operation of the EG&G ORTEC Gamma Spectroscopy System, Revision 10
7.4.63, Process Radiation Monitor Setpoints, Revision 13
7.4.64, Process Radiation Monitor Alarms, Revision 12
7.8.1, Chemistry Sample and Analysis Program, Revision 77
7.10.8, Main Stack, Reactor Building Vent, and Radwaste PRM Functional Check and Source Check, Revision 30
7.12.60, Garden Census, Revision 8
8.M.3-15, Main Stack Gas and Sample Flow Functional Test, Revision 8
8.M.3-16, Reactor Building Gas and Sample Flow Functional Test, Revision 11
8.M.3-17, Radioactive Liquid Effluent Flow Rate Instrument Functional and Calibration - Critical Maintenance, Revision 21
8.M.3-17.1, Radioactive Liquid Effluent Alternate Flow Rate (Liquid Level) Instrument Functional and Calibration, Revision 12
CN-CY-111-01, Tritium Recapture Sampling, Revision 0

EN-CY-102, Laboratory Analytical Quality Control, Revision 10
EN-CY-111, Radiological Groundwater Monitoring Program, Revision 7

Audits, Self-Assessments, and Surveillances:
LO-PNPLO-2017-033, Pre-NRC Inspection of Radioactive Gaseous and Liquid Effluent Treatment, Inspection Manual 71124-06, June 16, 2017
QA-2-6-2015-PNP-1, Entergy Pilgrim Quality Assurance Audit Report, Chemistry, Effluents and Environmental Monitoring, September 15, 2015

Condition Reports

2016-2037	2016-3221	2016-3221	2016-4462	2016-4619	2016-4619
2016-4619	2016-5815	2016-6408	2016-8496	2017-0258	2017-2238
2017-2655	2017-3026	2017-6072			

Maintenance Orders/Work Orders

00452044	00474833	02749606	52347555	52362206	52450789
52507342	52511337	52625397	52697959	52731382	52732121
52734553	52738236	52740617	52748439	52751582	52759387

Miscellaneous
6.6-116, Attachment 2, CHRMS Calibration Data Sheet, RIT-607B, December 6, 2016, Revision 18
6.6-116, Attachment 2, CHRMS Calibration Data Sheet, RIT-606A/B, -607A, April 11, 2016, Revision 18
2016 PNPS Annual Radioactive Effluent Release Report, May 12, 2017
Canberra 10000007928-442, Secondary Calibration Report for Pilgrim Nuclear Power Station Gaseous Effluent Monitoring Systems (GEMS) C3003 and C3004, April 3, 2017
Canberra 10000008127, Performance Report for Model MG4A (801032-001, Rev B) Gas Sampler with MDNR45E Detector, April 3, 2017
EN-LI-100 Attachment 9.1 Process Applicability Determination Form, Installation of New Liquid Radwaste Processing System (THERMEX) EC 63032, August 22, 2016
GEL Laboratories, LLC, 10CFR Part 50/61 Analysis: Certificate of Analysis, 2016 Bead Resin Composite collected April 21, 2016, June 3, 2016
MRAP-2016-003, Maintenance Rule a(1) Action Plan 45E and 45M, April 4, 2017
MRBD-45E, 45E Process Radiation Monitoring Systems, Revision 7
MRBD-45M, 45M Area Radiation Monitoring Systems, Revision 6
Pilgrim Nuclear Power Station Offsite Dose Calculation, Revision 11
Pilgrim Nuclear Power Station 2016 Garden Census Summary, February 22, 2017
Q1-17 - Radiation Monitoring, System Health Report, April 2017
Q2-17 - Radiation Monitoring, System Health Report, August 2017
Q4-16- Radiation Monitoring, System Health Report, January 2017
Results of Radiochemistry Cross Check Program Pilgrim Station, August 12, 2016

Liquid Effluent Waste Permits:
Liquid Radwaste Verification and Discharge Permit Number 2017001, January 4, 2017
Liquid Radwaste Verification and Discharge Permit Number 2017002, July 13, 2017

HEPA Filter and Charcoal Absorber Test Reviewed:
7.1.30, HEPA Filter and Charcoal Cell Performance Test Program, SBGT A, November 5, 2015, Revision 33

7.1.30, HEPA Filter and Charcoal Cell Performance Test Program, SBGT B, November 10, 2015, Revision 33
7.1.30, HEPA Filter and Charcoal Cell Performance Test Program, SBGT A, July 10, 2013, Revision 33
7.1.30, HEPA Filter and Charcoal Cell Performance Test Program, SBGT B, July 11, 2013, Revision 33
7.1.44, Sampling of Charcoal Cells in SBGT and Control Rm Environments Filters' Systems for Methyl Iodide Testing, SBGT A, November 10, 2015, Revision 23
7.1.44, Sampling of Charcoal Cells in SBGT and Control Rm Environments Filters' Systems for Methyl Iodide Testing, SBGT A, July 10, 2013, Revision 23
7.1.44, Sampling of Charcoal Cells in SBGT and Control Rm Environments Filters' Systems for Methyl Iodide Testing, SBGT B, July 11, 2013, Revision 23

Section 2RS7: Radiological Environmental Monitoring Program

Procedures
7.12.1, Administration of the Radiological Environmental Monitoring Program, Revision 11
7.12.10, REMP Sample and Analysis Tracking, Revision 6
7.12.20, Collection, Identification, and Laboratory Analysis of Radiological Environmental Monitoring Samples, Revision 6
7.12.25, Air Particulate and iodine Filter Preparation and Collection, Revision 15
7.12.30, Surface Water Sampling, Revision 10
7.12.40, Exchanging TLDs, Revision 12
7.12.45, Marine Life Sampling, Revision 8
7.12.50, Bottom Sediment Sampling, Revision 7
7.12.60, Garden Census, Revision 8
7.1.88, Operation of Sigma Composite Samplers, Revision 8
8.E.71, Surveillance, Maintenance and Calibration of 160' MET Tower MeDAP Equipment, Revision 16
8.E.72, Surveillance, Maintenance and Calibration of 220' MET Tower MeDAP Equipment, Revision 7
EN-CY-111, Radiological Groundwater Monitoring Program, Revision 7
EN-CY-111-01, Tritium Recapture Sampling, Revision 0

Audits, Self-Assessments, and Surveillances
DTE-NAQA-17-0038, Audit Report 17-007 – Audit of the Environmental Dosimetry Company, September 1, 2017
LO-PNPLO-2015-00022, Groundwater Tritium Self-Assessment for NEI-07-07 Objectives 2.1 through 2.4, December 18, 2015
LO-PNPLO-2014-00038, Groundwater Tritium Self-Assessment for NEI-07-07 Objectives 1.1 through 1.5, November 20, 2014
LO-PNPLO-2012-00016, Groundwater Tritium Snapshot-Assessment for NEI-07-07, March 26, 2012
NEI Peer Assessment for Pilgrim Nuclear Power Station, February 8, 2010
NUPIC Audit 24191, Teledyne Brown Engineering, Environmental Services Laboratory Audit, June 10, 2016
Pilgrim Nuclear Power Station Self-Assessment, Pre-NRC Inspection of REMP, August 21, 2017
QA-2-6-2015-PNP-1, Quality Assurance Audit Report, Chemistry, Effluents and Environmental Monitoring, September 15, 2015
WT-WTHQN-2015-00728, Entergy Audit of Teledyne Brown, Audit Report, July 8, 2016

WT-WTHQN-2015-00728, Entergy Audit of Teledyne Brown, Audit Closeout, October 27, 2016
WT-WTPNP-2010-00222, ERM Hydrological Dye Study for Condensate Storage Tank Flow, November 20, 2014

Condition Reports

2015-6716	2015-9556	2016-2228	2017-8383	2017-9151	2017-9356
2017-9393	2017-9395	2017-9413	2017-9417		

Maintenance Orders/Work Orders

52592502	52594258	52715494	52715501	52726233

Miscellaneous
Entergy - Quality Assurance Program Manual, Revision 33
Environmental Resources Management letter to Fred Mogolesko, Pilgrim Engineering, RE: FLEX Well PW-1 72 Hour Pumping Test – Water Management Approach, June 11, 2014
Environmental Resources Management letter to Ken Sejkora Pilgrim Chemistry, RE: Summary of 2015 Hydraulic Testing, December 28, 2015
Environmental Dosimetry Company, Annual Quality Assurance Status Report, January – December 2015, February 29, 2016
Environmental Dosimetry Company, Annual Quality Assurance Status Report, January – December 2016, March 8, 2017
Exelon Certificate of Calibration # 0010946819 for Sprague Gas Meter No. 175, Serial Number 3433485, April 11, 2016
Exelon Certificate of Calibration # 00109855500 for Sprague Gas Meter No. 175, Serial Number 1600139, February 20, 2017
FSAR Ch 2 A and B Onsite Meteorological Data and 2.4 Hydrology
Maintenance and Calibration of the REMP Air Sampler, Revision 9
Normandeau Associates, Inc., Quality Assurance Program, June 2017
Normandeau Associates, Inc., Procedure No. 7.12.45, Pilgrim Nuclear Power Station – Marine Life Sampling, July 2015
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 006354022 (A/S Station # 1), December 5, 2014
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 006354020 (A/S Station # 3), December 5, 2014
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 003604371 (A/S Station # 6), December 5, 2014
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 003605118 (A/S Station # 7), April 11, 2016
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 006354028 (A/S Station # 9), December 5, 2014
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 003604367 (A/S Station # 10), February 20, 2017
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 003601308 (A/S Station # 15), April 11, 2016
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 006354021 (A/S Station # 17), December 5, 2014
PNPS 7.12.80 Attachment 2 REMP Air Sampler Gas Meter Calibration Form – Gas Meter Serial Number 003601316 (A/S Station # 00), April 11, 2016
Pilgrim Nuclear Power Station – Offsite Dose Calculation Manual, June 12, 2017
Pilgrim Nuclear Power Station Annual Radiological Environmental Operating Report's, May 13, 2016, and May 12, 2017

Teledyne Brown Engineering, Annual 2015 Quality Assurance Report January – December 2015, May 9, 2016
Teledyne Brown Engineering, Annual 2016 Quality Assurance Report January – December 2016, April 19, 2017
Teledyne Brown Engineering, Results of Environmental Cross Check Program – 1st Quarter 2017, June 27, 2017

Section 4OA1: Performance Indicator Verification

Procedures
EN-LI-114, Regulatory Performance Indicator Process, Revision 7

Section 4OA2: Problem Identification and Resolution

Procedures
EN-VALVE-CHECK-Various, PM Basis Template, Revision 1
EN-DC-153, Preventative Maintenance Component Classification, Revision 14
EN-Valve- Air Operated, PM Basis Template Revision 1,
EN-DC-335, PM Basis Template, Revision 8
EN-DC-205, Maintenance Rule Monitoring, Revision 6
EN-LI-102, Corrective Action Program, Revision 30
EN-WM-101, On-line Work Management Process, Revision 14

Condition Reports

2003-0557	2003-0571	2004-0852	2005-0254	2006-3535	2007-0203
2007-2885	2012-1045	2013-5023	2013-1197	2014-0324	2015-7486
2011-0341	2017-5075				

Maintenance Orders/Work Orders

473404	421473	480905	461824	465142

Miscellaneous
Licensee Event Report 2017-005-00, Appendix J, Option B Leak Rate Criteria Exceeded
Root Cause Evaluation for Cycle 21 Appendix J leakage

Drawings
M244 SH1, P&ID HPCI System, Revision 31
M243, P&ID HPCI System, Revision 55

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures
1.8.1, Administration of Station Predefine, Revision 4
8.7.4.8.2, PASS Panel Water Isolation Valve Position Indication Verification, Revision 4
8.E.65, Containment Pressure, Water Level, And Torus Pressure Instrumentation Calibration - Critical Maintenance, Revision 29
8.Q.2-2, Rosemount Transmitter Circuit Board And Sensor Module Replacement, Revision 15
8.Q.3-2, RHR/Core Spray Pump Motor Preventive Maintenance, Revision 24
8.Q.3-5, NAMCO Limit Switch EQ Repair, Revision 19
8.Q.3-5, NAMCO Limit Switch EQ Repair, Revision 22

8.Q.3-8.2, Limitorque Type HBC, SB/SMB-0 Through SB/SMB-3 Valve Operator Maintenance – Critical Maintenance, Revision 24
E-36, Environmental Parameters for Use in the Environmental Qualification of Electrical Equipment (per 10CFR50.49), Revision 11
E-536, ENN Engineering Standard Pilgrim Unit 1, Revision 11
EN-DC-164, Environmental Qualification Program, Revision 4
EN-DC-324, Preventive Maintenance Program, Revision 17
EN-DC-335, PM Basis Template, Revision 7

Vendor Documents
V0055, Barton Instruments, Revision 25
V0348, Bingham Pumps, Revision 17
V0390, Limitorque Valve Controls, Revision 35
V0426, NAMCO Limit Switch Assemblies, Revision 14

Equipment Qualification Data File Cover Sheets (EQES)
EQES, A1 KERITE (OC), Revision 4
EQES, DPIS-2352-EQES, Revision 9
EQES, J208, Junction Box, Revision 11
EQES, MO-1301-49-EQES, Revision 11
EQES, MO-2301-35, Revision 7
EQES, MO-2301-4, Connectors (LUGS) AMP (1C), Revision 7
EQES, MO-2301-4, Limit Switches – MOVS (1C), Revision 5
EQES, MO-2301-4, Motor Operated Valve Actuator, Revision 12
EQES, MO-2301-4, TERM Blocks – Marathon 300 for 120VAC, Revision 3
EQES, MO-2301-4, TERM Blocks for Limitorque-4, Revision 4
EQES, MO-2301-4, Torque Switch (1C), Revision 4
EQES, MO-2301-4, ZS2301-4 (1W), Internal Wiring, Revision 5
EQES, PASS Solenoid Valve SVSO6S-83, Revision 7
EQES, PT1001-6014, Revision 7
EQES, Raychem Splices (IC), Revision 13
EQES, VAC-204A-EQES, Revision 6
EQES, ZS-203-1A-1, Limit Switch/Connector, Revision 15
EQES, ZS-203-1A-3, Limit Switch/Connector, Revision 15
EQES, ZS-203-1A-5, Limit Switch/Connector, Revision 14
EQES, ZS-203-1A-6, Limit Switch/Connector, Revision 15

Qualification Maintenance Requirements (QMR)
QMR, Containment Pressure Transmitter PTI001-601A, Revision 3
QMR, DPIS-2352-QMR, Revision 2
QMR, HPCI Motor-Operated Valve MO2301-35, Revision 8
QMR, J208, Revision 2
QMR, MO-1301-49-QMR, Revision 8
QMR, MO-2301-4, HPCI Steam Supply Valve, Revision 11
QMR, Raychem Splices (IC), Revision 1
QMR, RHR Motor Power Cable A1 KERITE (OC), Revision 1
QMR, SVSO6S-83, Revision 1
QMR, VAC-204A-QMR, Revision 1
QMR, ZS-203-1A-1, NAMCO LIMIT SWITCH, Revision 3
QMR, ZS-203-1A-3, NAMCO LIMIT SWITCH, Revision 3

QMR, ZS-203-1A-5, NAMCO LIMIT SWITCH, Revision 3
QMR, ZS-203-1A-6, NAMCO LIMIT SWITCH, Revision 3

Equipment Qualification Reference Files (EQDF)
EQDF Ref 186, Qualification for Class 1E Motors, Revision B
EQDF Ref. 103, Qualification Verification Report on Barton Pressure Switches 288, 288A, and 298A for Use in Pilgrim 1 Nuclear Power Station, Revision B
EQDF Ref. 107, Qualification Test Procedure for Barton Models 288A and 289A Indication Switches per General Electric Company Environmental Specifications, Rev 0
EQDF Ref. 128, IEEE 344-1975 Seismic and Radiation Qualification Tests for ITT Barton Differential Pressure Indicating Switches Models 288A and 289A, Revision 0
EQDF Ref. 145, Generic Qualification of Series EA740 Switches for Use in Nuclear Power Plant Class 1E Application in Compliance with IEEE 323-74, 382-72, and 344-75, Revision E0
EQDF Ref. 145B, NAMCO Limit Switch for MSIVs in Drywell Supporting Information, Revision 3
EQDF Ref. 145D, Supplements 01, 02, 03, 04, and 05 to NAMCO Test Report QTR140 Qualification of EA740 Series Limit Switches, Revision E0
EQDF Ref. 145G, Qualification Test Report QTR140, Revision E0
EQDF Ref. 189, Qualification Verification Report on Westinghouse Motors – Model 215T for Use in Pilgrim Nuclear Power Station, Revision 0
EQDF Ref. 201, AMP Insulated Terminal and Splices for Class 1E IC Service in Nuclear Power Generating Stations, Revisions A and E1
EQDF Ref. 201A, Thermal Life of Polyvinylidene Fluoride Insulating Sleeves, Revision 0
EQDF Ref. 241, Determination of Equivalent Constant Year Round Temperature Based Upon Various Seasonal Temperatures Using Arrhenius Techniques, Revision E1
EQDF Ref. 387-A, Nuclear Environmental Test Program on a Marathon 300 Terminal Block for Use in 120 VAC Control Circuits, Revisions 0 and E0
EQDF Ref. 387-F, Nuclear Environmental Qualification Test Program on a Buchanan 0222 Terminal Block in a 480 Vac Circuit, Revisions 0 and E0
EQDF Ref. 416, Qualification Test Program on Limitorque Limit Switches, Marathon Terminal Blocks, Kerite Cables, Rosckbestos SIS Cables Test Report #42364-1, Revisions A and E0
EQDF Ref. 425, Nuclear EQ Test Report on Limitorque Components, Revisions B and E2
EQDF Ref. 445, NAMCO QTR 520 Qualification of Namco EA740-Series Limit Switches with EC290-Series Receptacles and Connector/Cable Assemblies, Revision E0
EQDF Ref. 451, EDR-5336, Nuclear Products Requalification Testing, Revision 0
EQDF Ref. 461, Test Report for NAMCO EA-180 and EZ-740 Limit Switches for use in Cooper Nuclear Station, EGS Report No. EGS-TR-902200-02, Revision A, 2/28/1995, Revision E3
EQDF Ref. 52A, Qualification Type Test Report Limitorque Valve Actuators with Type LR Motor from Westinghouse PWR, Report B0212, Revision 0
EQDF Ref. 77, Limitorque Actuator Qualification for Nuclear Power Station Service, Revision E0

Condition Reports

2007-0844	2008-0063	2012-4248	2017-4203	2017-4883	2017-4934
2017-5067	2017-5275	2017-5339	2017-5386*	2017-5417*	2017-5472*
2017-5473*	2017-5829*	2017-5883*	2017-6116	2017-6183*	2017-6184*
2017-6199*	2017-6207	2017-6575	2017-6577	2017-6578	2017-6579
2017-6580	2017-6582	2017-6718	2017-6725	2017-7397*	

* Written as a results of this inspection

Maintenance Orders/Work Orders

P9401855	P9401856	P9401857	P9401858	P9900724	P9900728

P9900757 P9900758 02101020 06108898 435308-01 52617072

Miscellaneous
17-0192-TR-003, Electrical Testing and Analysis of SV-203-3A and SV-203-3D, Revision 0
AES-10373239-01, Differential Indicating Switch Replacement Study, Revision 0
BWR Report 600376A, BWR Containment Qualification, 5/13/76
E-535, ENN Engineering Standard Pilgrim Unit 1, Revision 11
EQDF 388, Qualification Test Report for The Environmental Qualification of The Target Rock Corp. Solenoid Operated Globe Valves IAW Standard Case IV Conditions (Modified) IEEE 383-1980, dated 11/10/88
EQDF 388B, Qualification Test Report For The Environmental Qualification of The Target Rock Corp. 3 Way Valve, Solenoid Operated, P/N 1/2 SMS-S-02-1, In Accordance With IEEE 383-1985, dated 1/9/90
EQDF 388E, Addenda 1, 2, 3, and 4 to Target Rock Report 5074 (EQDFREF388B), Revision 1
Equipment Qualification Data File, Equipment ID SV203-3A, Revision 8, dated 4/17/07
Equipment Qualification Data File, Equipment ID SV203-3A, Revision 9, dated 5/12/17
Log 93-19, Request for Master List Revision (Temperature Switches), 5/13/93
Log 94-03, Request for Master List Revision (Cables), 2/12/93
Log 94-05, Request for Master List Revision (Cables), 10/6/94
MRIR 90-2960, Solenoid Purchase Order for PDC89-052, dated 4/23/91
PMBD-279, PM Basis Document for SRV Solenoid Operated Valves, Revision 0
PNPS-RPT-05-006, Pilgrim Nuclear Power Station Mitigating System Performance Index (MSPI) Basis Document, Revision 5
Qualification Maintenance Requirements, Equipment ID SV203-3A, Revision E1, dated 6/7/99
Qualification Maintenance Requirements, Equipment ID SV203-3A, Revision 2, dated 5/12/17
RIR 03-0361, Solenoid Valve Assembly, dated 5/5/03
Rtype B4.60, PNPS Environmental Qualification Master List, Revision E51
Troubleshooting Plan, CR-17-5275, WO 475506, dated 5/5/17
T03, Design Guide for Environmental Qualification of Electrical Equipment, Revision E3
V-0353, Target Rock Safety Relief Valve Model 7567F, Revision 15

Drawings
M203, Sh. 1, Main Steam, Revision 48
M203, Sh. 2, Main Steam, Revision 34
M203, Sh. 3, Main Steam, Revision 44
M243, HPCI System, Revision 55
M244, Sh. 1, HPCI System, Revision 31

LIST OF ACRONYMS

ACA	adverse cause analysis
AOP	abnormal operating procedure
CAP	corrective action program
CFR	*Code of Federal Regulations*
CS	core spray
CR	condition report
DOR	Division of Operating Reactors
DPIS	differential pressure indication switch
Ea	activation energy
EAL	emergency action level
eV	electron volts
EDG	emergency diesel generator
EQ	environmental qualification
FSAR	Final Safety Analysis Report
GPI	Groundwater Protection Initiative
HPCI	high pressure coolant injection
IMC	Inspection Manual Chapter
LLRT	local leak rate testing
LOCA	loss of coolant accident
LPCI	low pressure coolant injection
MSIV	main steam isolation valve
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
ohm	volt-ohm-meter
PNPS	Pilgrim Nuclear Power Station
PM	preventive maintenance
psig	pounds per square inch
QMR	qualification maintenance requirement
RCIC	reactor core isolation cooling
REMP	Radiological Environmental Monitoring Program
RFO	refueling outage
RHR	residual heat removal
SBODG	station blackout diesel generator
SCFH	standard cubic feet per hour
SDP	Significance Determination Process
SLM	standard liters per minute
SOARCA	State-of-the-Art Reactor Consequence Analyses
SRA	Senior Reactor Analyst
SRV	safety relief valve
SSC	structure, system, or component
SSW	salt service water
TS	technical specification
URI	unresolved item
UT	ultrasonic testing
WO	work order