UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

September 30, 2005

Joseph E. Venable
Vice President Operations
Waterford 3
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

SUBJECT: WATERFORD STEAM ELECTRIC STATION, UNIT 3 - SPECIAL INSPECTION REPORT 05000382/2005010

Dear Mr. Venable:

On September 14, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection at your Waterford Steam Electric Station, Unit 3. The special inspection was performed in response to an event which involved reactor coolant system configuration issues that resulted in a vacuum being drawn in the reactor coolant system during a draindown evolution. This event met two of the criteria specified in NRC Management Directive 8.3, "NRC Incident Investigation Program." These criteria were satisfied because the event involved significant unexpected system interactions and the event raised questions or concerns pertaining to licensee operational performance.

The enclosed report documents the inspection results, which were discussed on August 2, 2005, with Mr. Alan Harris and other members of your staff. On September 14, 2005, an exit was held with Mr. J. Venable and other members of your staff to convey the final disposition of inspection findings. The determination that the inspection would be conducted was made by the NRC on May 5, 2005, and the inspection started on June 20, 2005.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

There were four self-revealing findings of very low safety significance (Green) identified in this report. These findings involved violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section VI.A of the Enforcement Policy. These findings are described in the subject inspection report. If you contest the subject or severity of this noncited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Waterford Steam Electric Station, Unit 3, facility.

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

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

David N. Graves, Chief
Project Branch E
Division of Reactor Projects

Docket: 50-382
License: NPF-38

Enclosure:
1. NRC Inspection Report
   05000382/2005010
2. Charter for Special Inspection

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-382
License:	NPF-38
Report:	05000382/2005010
Licensee:	Entergy Operations, Inc.
Facility:	Waterford Steam Electric Station, Unit 3
Location:	Hwy. 18 Killona, Louisiana
Dates:	June 20-24, 2005
Inspectors:	V. G. Gaddy, Senior Project Engineer, Division of Reactor Projects G. F. Larkin, Resident Inspector, Division of Reactor Projects M. S. Haire, Operations Engineer, Division of Reactor Safety W. C. Lyon, Senior Reactor Engineer, Office of Nuclear Reactor Regulation
Approved By:	D. N. Graves, Chief, Project Branch E

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000382/2005-010; 06/20/2005 - 06/24/2005; Waterford Steam Electric Station, Unit 3; Special Team Inspection

This report covered a period of inspection by four inspectors. Four Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

C Green. A self-revealing noncited violation of Criterion XVI of Appendix B of 10 CFR Part 50 was identified for the failure to promptly identify and correct the vacuum condition in the reactor coolant system during draindown, a condition adverse to quality. Control room operators missed several opportunities over a 32.5-hour period to identify that a vacuum had been drawn on the reactor coolant system to correct the vacuum condition. The licensee documented this issue and their corrective actions in Condition Report CR-WF3-2005-1463. This finding has crosscutting aspects associated with problem identification and resolution for the failure to promptly identify and correct the vacuum condition.

This finding is greater than minor because if left uncorrected it could have become a more safety significant concern, it was associated with the human performance attribute of the mitigating systems cornerstone, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, "Shutdown Operations," Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available net positive suction head available to the operating shutdown cooling pumps at the low reactor coolant system pressure. The inspectors determined the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps (Section 3.8).

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation with three examples of Technical Specification 6.8.1.a was identified. The first involved the failure to implement Procedure OP-001-003, "RCS Drain Down," in establishing a reactor coolant system vent path when a nuclear auxiliary operator failed to open the reactor vessel vent line isolation valve as required. The licensee documented this issue and its corrective actions in Condition Report CR-WF3-2005-1463. The second violation of Technical Specification 6.8.1.a involved the failure to implement Procedure OP-100-001, "Operation Standards and Management Expectations," for providing a proper peer check for valve manipulations when a nuclear auxiliary operator failed to provide the required local peer check for opening the reactor vessel vent line isolation valve and erroneously agreed with the report that the valve had been properly opened and a vessel head vent path had been established. The licensee documented this issue and its corrective actions in Condition Report CR-WF3-2005-1463. The third violation of Technical Specification 6.8.1.a was identified for failure of the prejob brief to provide the nuclear auxiliary operators the required knowledge and information needed to successfully establish vent paths for the pressurizer and reactor vessel as required by procedure. The nuclear auxiliary operators responsible for establishing the vent paths did not attend this briefing as required. The licensee documented this issue and its corrective actions in Condition Report CR-WF3-2005-1463. This finding has human performance crosscutting aspects associated with three failures to follow procedure.

  This finding is more than minor because if left uncorrected it could have become a more safety significant concern, it was associated with the human performance attribute of the initiating events cornerstone, and it affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenged critical safety functions during shutdown operations. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, "Shutdown Operations," Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available net positive suction head available to the operating shutdown cooling pumps at the low reactor coolant system pressure. The inspectors determined the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps (Sections 3.3.1, 3.3.2, and 3.3.4).

- Green. A self-revealing noncited violation of Technical Specification 6.8.1.a was identified for failure to establish an adequate procedure to govern reactor coolant system inventory reductions. The reactor coolant system draindown procedure failed to identify that temporary vent rigs, required by procedure to properly establish vent paths, included in-line ball valves in series with the vent path and also failed to direct that those ball valves be opened to establish the vent path. As a result of this procedural inadequacy, one of the vent rig ball valves remained closed and the reactor coolant system remained unvented during the subsequent draindown, which caused the pressure in the reactor coolant system to drop below atmospheric. The licensee documented this issue and its corrective actions in Condition Report CR-WF3-2005-1463. This finding has problem identification and resolution crosscutting aspects because the licensee was aware of and did not fix the procedure to address the ball valves in 2002.

This finding is more than minor because if left uncorrected it could have become a more safety significant concern, it was associated with the procedure quality attribute of the initiating events cornerstone, and it affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, "Shutdown Operations," Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available net positive suction head available to the operating shutdown cooling pumps at low reactor coolant system pressure. The inspectors determined the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps (Section 3.3.3).

- Green. A self-revealing, noncited violation of Technical Specification 6.8.1.a was identified for failure to establish an adequate procedure to govern the integrated leak rate test for the containment vessel. The procedure for the test failed to prevent a plant configuration that allowed air to be entrained in the reactor coolant system and subsequently come out of solution and form a void in the reactor vessel head. The licensee documented this issue and its corrective actions in Condition Report CR-WF3-2005-2461. This finding has a human performance crosscutting aspect associated with procedure quality.

  This finding is more than minor because it is associated with the configuration control attribute of the initiating events cornerstone and affects the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. The inspector utilized the NRC Inspection Manual Chapter 0609 Significance Determination Process Phase 1 Screen Worksheet for Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones to assess the safety significance. The finding was determined to be of very low risk significance since adequate mitigation capability remained available (Section 3.13).

B. Licensee-Identified Violations

None

REPORT DETAILS

1.0 INTRODUCTION

1.1 Special Inspection Scope

The NRC conducted this inspection to gain a better understanding of the circumstances surrounding and the risk significance associated with the April 18, 2005, reactor coolant system (RCS) configuration control issues that resulted in a vacuum being drawn in the RCS during a draindown evolution at the Waterford 3 Steam Electric Station.

The inspection team used NRC Inspection Procedure 93812, “Special Inspection.” The specific items for investigation were outlined on the special inspection team charter, provided as Attachment 2. The special inspection team reviewed procedures, corrective action documents, work requests, engineering calculations, and the root cause analysis reports. The team also interviewed key plant personnel regarding the event, the root cause analysis, and corrective actions. A list of personnel interviewed and documents reviewed are provided as Attachment 1.

1.2 Preliminary Significance of Event

The NRC staff considered both deterministic and safety significance criteria, established in NRC Management Directive 8.3, “NRC Incident Investigation Program,” to determine whether a special inspection would be performed. The NRC staff determined that the following two deterministic criteria were met: (1) The event involved significant unexpected system interactions -- A vacuum in the RCS was created due to the failure by the licensee to ensure that the reactor vessel head vent and pressurizer vent valves were open before beginning the RCS draindown to 1 foot below the reactor vessel flange (19 feet) and conditions present in the shutdown cooling system (SDC) led to coolant flashing and the creation of bubbles of noncondensable gasses which passed through the SDC pumps, causing pump amperage to drop and flow fluctuations; and (2) The event involved questions or concerns pertaining to licensee operational performance -- A vacuum in the RCS was created due to the failure by the licensee to ensure that the reactor vessel head vent and pressurizer vent valves were open before beginning the RCS draindown to 1 foot below the reactor vessel flange (19 feet) and the licensee failed to recognize the conditions that could have led to a loss of SDC.

An NRC senior reactor analyst performed a preliminary risk assessment using the Palo Verde Shutdown SPAR to evaluate Mode 5, Early Time Frame Reduced Inventory, Intact Reactor Coolant System with open loops. (A shutdown SPAR model for Waterford 3 is not available.) This configuration related to Plant Operating State POS-M5ERIO and appropriately represented the status of the plant during the time that the majority of risk was caused by the failure of operators to make up to the reactor following the loss of the residual heat removal system. This appeared valid, especially considering that the operators had assumed that the indications they were seeing were driven by the inability of the system flow controllers to maintain flow at the high heat loads. This may have misled the operators to focus recovery attempts on the residual heat removal system itself, rather than making up to restore net positive suction head (NPSH). Based on these assumptions, the estimated incremental conditional core damage probability was 2E-5.

2.0 EVENT DESCRIPTION

On the day shift on April 18, 2005, pressurizer level was 100 percent, RCS temperature was approximately 120EF, and both trains of SDC were in service. Control room operators completed the initial depressurization of the RCS prior to transitioning to cold shutdown. The initial depressurization secured recirculation and cooldown of the pressurizer at 9:45 a.m., with pressurizer temperature of 186EF, and prepared the RCS for lowering pressurizer level to between 5 and 75 percent cold calibrated level.

At 12:50 p.m., maintenance installed a temporary vent rig on the flanged connection downstream of the pressurizer spray vent valve, RC-309. Installation of the vent rig was controlled by Work Order 34550. This work order did not specify the required configuration of the temporary vent rig and did not provide administrative controls for the temporary ball valve that was installed. The rig was installed with the ball valve closed and the operating handle removed.

Shortly after installation of the vent rig, a nuclear auxiliary operator (NAO) was dispatched to open Valve RC-309. This step was necessary to vent the pressurizer in order to drain the pressurizer to between 5 and 75 percent cold calibrated level. The NAO opened Valve RC-309, but neither the NAO nor his peer checker were aware of the closed temporary ball valve blocking the vent path. This was a first time evolution for both the NAO and the peer checker. The NAO reported to the control room that the vent path had been established.

At 2:57 p.m., operators began draining the RCS to a level of 10-20 percent in the pressurizer. A postevent review of the archived plant computer data showed that, as the draining of the RCS proceeded, wide-range pressurizer pressure began to slowly drop, and at approximately 3 p.m., indicated RCS pressure dropped below atmospheric.

At 5 p.m., work management placed an open danger tag on Valve RC-309. The tagout was hung to facilitate pressurizer manway removal. The NAO hanging the danger tag along with his peer checker verified that Valve RC-309 was open. However, neither noticed, nor were they aware of the installed temporary ball valve blocking the vent path. Shortly after the danger tag was hung, a third NAO entered containment and verified that Valve RC-309 was open.

Prior to 6 p.m., as directed by Work Order 57341, the refueling group removed the normal reactor vessel head vent piping downstream of Valve RC-10111, the reactor coolant isolation to reactor vessel vent line. When in service, this piping functioned as the vessel head vent path to the quench tank and is removed for refueling. The refueling group then installed a temporary vent rig at the Valve RC-10111 flange. The work order did not specify the required configuration of the temporary vent rig and did not provide administrative controls for the temporary valve that was installed. The temporary vent rig was installed with its valve closed and operating hand-wheel installed.

At 6 p.m., operators began lowering pressurizer level to 5 percent (~30 feet mean sea level (MSL)). After approximately an hour, draining was temporarily suspended at 26 percent pressurizer level and RCS pressure was indicating between 9 and 11 psia. Operators believed this pressure indication was representative of atmospheric pressure with some allowances for instrument error.

At 4:55 a.m., on April 19, with pressurizer level at 5 percent, operators stopped draining the RCS and transitioned to Procedure OP-001-003, “Reactor Coolant System Drain Down.” Nuclear auxiliary operators were dispatched to containment to vent the reactor vessel head as required by procedure. When opened, water issued from Valve RC-10111 even though a vacuum existed in the RCS. The NAO indicated that he observed a solid, steady stream of water and bubbles from the vent. The licensee subsequently determined that prior to venting from Valve RC-10111, its vent hose contained water and was routed over the ledge from the upper refueling cavity to the lower refueling cavity. The licensee believed that this elevation change in the hose downstream from Valve RC-10111 was sufficient to cause the water flow.

At about 5:01 a.m., draining the RCS to 24 feet MSL began. During the draindown, while performing level cross checks, operators noted that RCS level was rising while refueling water storage pool (RWSP) level was dropping. Operators, preconditioned by the previous knowledge of leakage past SI-109A/B (LPSI suction isolation valves), attributed the RCS level rise to leakage past these valves.

At the 24 foot RCS level, draining was secured and an NAO was directed to vent the vessel head by opening Valve RC-10111. The NAO incorrectly identified the temporary vent rig valve as Valve RC-10111 and opened the temporary vent rig valve, leaving Valve RC-10111 closed. The peer check was performed from a distance of about 25-30 feet due to ALARA concerns. The NAO then reported that Valve RC-10111 was open.

At 7:44 a.m., an NAO was dispatched to check closed Valves SI-109A/B. Valve SI-109A was closed an additional two turns and Valve SI-109B was closed an additional three turns.

At 9 a.m., with pressure indicating 6 psia, the control room directed instrumentation and control to enter containment and check actual pressure using a temporarily installed test instrument. The initial pressure reading was measured as 23 psia. The control room operator doubted this measurement and directed Instrumentation and Control (I&C) to drain the reference leg and remeasure pressure. This action drained the condensate pot and reference leg until the pressure at the drain location was equal to atmospheric pressure (15 psia). At this point pressure due to the water remaining in the reference leg plus the RCS pressure reference leg was balanced by the pressure from the atmosphere. However, I&C incorrectly believed the reference leg had been drained. Consequently the remeasurement indicated 15 psia. Believing that the RCS was at atmospheric pressure (15 psia), operators continued draining the RCS.

At 10:30 a.m., operators closed the RWSP Train A outlet isolation valve to reduce leakage from the RWSP.

At approximately 11 a.m., while draining to 18.5 feet, operators noted a temperature rise (7EF) in the RCS. Oscillations were also noted at the output of the Train B SDC flow control valves. SDC pump amperage oscillations were also noted. Operators attributed the temperature rise to the flow oscillations. The flow controller was placed in manual and the oscillations stopped. I&C personnel were dispatched to evaluate the controller. No problems were noted. The controller was returned to automatic. At about 1:30 p.m., the oscillations (flow/amperage and a temperature rise (~10EF)) repeated, this time on both trains. The flow controllers were placed in manual, the oscillations stopped, and the temperature stabilized. Operators considered this condition to determine if it met the entry conditions for Off-Normal Operating Procedure OP-901-131, “Shutdown Cooling Malfunction.” Operators concluded that entry into the off-normal mode was not warranted since there were no consistent indications that the pump amps and flow were responding to anything other than a sluggish flow controller.

The parameter changes actually resulted from anomalies induced in the suction piping of the SDC pumps as a result of achieving saturation conditions at the highest point in the SDC pump suction piping.

SDC flow was then reduced to 3000 gpm and no further problems were noted with SDC flow. Operators resumed draining the RCS and stopped at the 19.1 foot level. Over a 4.5-hour period RCS level increased 0.8 feet. This was due to continued inleakage from the RWSP.

At approximately 10-10:30 p.m., operators lowered level to approximately 19 feet. However, due to inleakage from the RWSP, RCS level rose about 0.15 feet over the next 90 minutes. At approximately 11 p.m., maintenance personnel began unbolting and removing the pressurizer manway cover. Removal of the manway was required prior to going below 18 feet in the RCS. This provided a vent path in accordance with Procedure OP-010-006, “Outage Operations.” Attachment 9.11 required that the manway be removed prior to installing nozzle dams to ensure that adequate hot side venting was provided. Following removal of the manway, maintenance personnel attempted unsuccessfully to remove the manway diaphragm installed beneath the cover. At 11:30 p.m., maintenance personnel determined that the diaphragm could not be removed. The control room staff was notified shortly thereafter, providing indication of a partial vacuum in the RCS.

Operations sent personnel into containment to once again verify the RCS vent paths. At 12:30 a.m., on April 20, an NAO determined that there was a closed temporary valve on the vent rig downstream of Valve RC-309. At about 3 a.m., NAOs determined that

Valve RC-101111 was closed. At this point, operators stopped all evolutions that could result in changes in RCS pressure or level and communicated the vacuum condition to management.

Following development of a recovery plan, operators began raising level in the RCS. Recovery involved slowly venting the pressurizer through Valve RC-309 vent rig while using the charging pumps to maintain RCS level between 20 and 24 feet. Restoration of the RCS to atmospheric pressure was completed at 06:45 a.m., on April 21.

3.0 **SPECIAL INSPECTION AREAS**

3.1 Sequence of Events

a. Inspection Scope

The inspectors developed a sequence of events based on plant computer data and plant parameters, operator logs, and interviews with licensee staff. The inspector-developed sequence of events was compared with the licensee's sequence of events to determine whether the event had been adequately captured and reviewed. The sequence of events is included in Attachment 3.

b. Findings

No findings of significance were identified.

3.2 Condition in the RCS for Temperature, Pressure, and Water Inventories

a. Inspection Scope

The inspectors evaluated the state of the RCS during the approximate 32.5-hour period that a vacuum was drawn on the RCS. The inspectors focused on the temperature, pressure, and water inventories.

b. Findings

On April 19, 2005, at approximately 11 a.m. and again at 1:30 p.m., SDC flow, pressure, temperature, and pump motor current fluctuations occurred. The licensee subsequently determined that this was due to insufficient RCS pressure to maintain void-free operation at the upper SDC piping.

The licensee concluded that the voids caused an increased pressure drop in the SDC piping that reduced pressure at the pump inlet and caused minor pump cavitation, but did not result in a loss of SDC flow. The inspectors performed a thorough evaluation of all relevant plant parameters to fully understand the event. The inspectors concluded that, although minor cavitation occurred and there was a reduction in the available NPSH available to the SDC pumps, SDC flow remained sufficiently high that core cooling was not significantly affected. Specific evaluations are as follows:

3.2.1 RCS Conditions

Reduced inventory occurred whenever RCS level was drained to less than 18 feet MSL. During this event, the licensee had controls in place to prevent RCS level from being drained to less that 18.5 feet MSL. The draindown procedure required the pressurizer manway be removed before draining below 18 feet to install the nozzle dams, and it was the attempt to remove the manway that resulted in discovery of the RCS low pressure condition. The lowest level reached during the draindown event was approximately18 feet 8 inches.

The licensee noted that the indicated cold calibration pressurizer level was less than 100 percent with the RCS in a solid condition when commencing to drain the pressurizer on April 18. This was consistent with operational experience that all gas was not removed from the pressurizer during venting to the volume control tank. Additionally, small quantities of gas were expected in the top of the reactor vessel head and in the upper elevations of the steam generator tubes prior to RCS draining. As draining commenced, the gas initially expanded until pressurizer pressure equalized with the vapor pressure of water at the gas/water interface, at which time water boils and water vapor contributes to the gas volume. A similar process occurred in the reactor vessel head and steam generator tubes. Water from these three sources would then flow into the RCS as the draindown progressed.

During the event, the inspectors reviewed the available core exit thermocouple temperature indicators. During the event on April 19, core exit thermocouple indicators typically ranged between 120EF and 125EF. However, immediately prior to the first SDC Train A flow fluctuation, temperature peaked at 131EF at approximately 11 a.m. and returned to normal 2 hours later. (Normal flow was about 4000 gpm. Flow fluctuations ranged from about 3500-4200 gpm.) At approximately 1:30 p.m., another temperature increase (127EF) occurred at the same time that both trains of SDC experienced fluctuations. Temperature gradually returned to normal over the next several hours. The 131EF value corresponded to a saturation pressure of about 2.3 psia. At 11 a.m., pressure was about 5.5 psia and RCS water level was 18.6 feet MSL. Since the upper level of the hot leg was at 15.1 feet MSL, pressure at this elevation was about 7 psia. Pressure at the top of the reactor vessel upper head (24 feet MSL) was about 3.2 psia. At 3.2 psia, the temperature would have to be greater than about 143EF for a vapor void to form in the upper head. Based on the available indications, the inspectors concluded that a significant vapor void did not form in the reactor vessel upper head.

3.2.2 SDC Condition and Operations

As the RCS was drained without a vent path, pressure dropped below atmospheric, creating a vacuum in the RCS. At approximately 38 percent cold calibration pressurizer level, the steam generators achieved saturation conditions. As pressure lowered as a result of the draindown, saturation conditions were achieved in the SDC piping at the 23 foot elevation, the SDC high point. Entergy estimated that the pressure at the high point in the SDC piping (23 ft MSL) was <2 psia. As water flashed to steam, noncondensable gases were released and the head loss at the 23 foot piping area increased, reducing the NPSH available to the SDC pumps. Minor indications of cavitation (fluctuations in flow and amperage) occurred twice in SDC Pump A piping and once in SDC Pump B piping. The vapor bubbles formed at the 23 foot elevation were swept down the SDC suction piping and collapsed as elevation head raised pressure and the noncondensable gases were swept through the SDC pumps. A rise in the RCS level due to RWSP inleakage restored SDC Pump A flow on the first occasion, and a flow reduction of 1000 gpm to 3000 gpm per pump restored SDC flow on the second occasion. Raising RCS level and reducing SDC flow raised NPSH available at the SDC pumps and stopped the minor cavitation. Although minor indications of pump cavitation occurred, the pumps remained functional throughout the event.

3.3 Assessment of Controls in Place for Establishing Adequate Vent Paths for Initial RCS Inventory Reduction and Reduced/Midloop Operation

a. Inspection Scope

The inspectors reviewed the licensee's controls that were in place for establishing adequate vent paths for initial RCS inventory reduction and reduced/midloop operations. The team reviewed the licensee's root cause analysis, draindown procedures, corrective action documents, work orders, and Technical Specifications and interviewed operators, system engineers, and work control supervisors.

b. Findings

.1 Introduction. An example of a Green self-revealing noncited violation of Technical Specification 6.8.1.a was identified for the failure to implement Procedure OP-001-003, "RCS Drain Down," while establishing an RCS vent path.

Description. On April 19, 2005, Procedure OP-001-003, "RCS Drain Down," directed an NAO to open Valve RC-10111, the reactor coolant isolation to reactor vessel vent line, to establish a vent path for the RCS. The NAO, unfamiliar with the exact location of Valve RC-10111 (behind a shield panel) and also unfamiliar with the temporary vent rig installed downstream of Valve RC-10111, mistakenly opened the unlabelled ball valve in the temporary vent rig and left Valve RC-10111 closed. The NAO then reported to the control room that Valve RC-10111 had been opened and that the vent path had been established. In actuality, Valve RC-10111 remained closed and the reactor vessel vent path remained isolated. This failure to follow procedure allowed the RCS to remain unvented during the subsequent RCS draindown which caused the pressure in the RCS to drop below atmospheric.

Analysis. The failure to follow procedure while attempting to establish a reactor vessel vent path is a performance deficiency. The finding was more than minor because if left uncorrected it could have become a more safety significant concern and because it was associated with the human performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination

Process, Appendix G, "Shutdown Operations," Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available net positive suction head available to the operating SDC pumps at the low RCS pressure. The inspectors determined that the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps

In addition, this finding had crosscutting aspects associated with human performance for the failure to follow procedure.

Enforcement. Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, Revision 2. Regulatory Guide 1.33, Appendix A, Section 3.a, requires procedures be established, implemented, and maintained with instructions for draining the RCS. Contrary to this requirement, the NAO failed to implement Procedure OP-001-003, "RCS Drain Down," by failing to open Valve RC-10111 as directed by step 6.2.9.2.2 of the procedure. This failure to establish a vent path for the RCS during draindown caused subsequent draining of the RCS to reduce RCS pressure below atmospheric, resulting in a partial vacuum being drawn on the RCS. Because the failure to implement a required procedure was determined to be of very low risk significance and has been entered into the licensee corrective action program as Condition Report CR-WF3-2005-1463, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000382/20050010-01; Failure to implement required procedure for RCS draindown procedure.

.2 Introduction. An example of a Green self-revealing noncited violation of Technical Specification 6.8.1.a was identified for failure to implement Procedure OP-100-001, "Operation Standards and Management Expectations," for providing a proper peer check for valve manipulations.

Description. On April 19, 2005, an NAO was directed to open Valve RC-10111, reactor coolant isolation to reactor vessel vent line, to establish a vent path for the RCS per Procedure OP-001-003, "RCS Drain Down." A second NAO was sent to provide a peer check on the valve position. The NAO, unfamiliar with the exact location of Valve RC-10111 (behind a shield panel) and also unfamiliar with the temporary vent rig installed downstream of Valve RC-10111, mistakenly opened the unlabelled ball valve in the temporary vent rig and left Valve RC-10111 closed. The second NAO conducted the peer check from a distance of greater than 25 feet in order to minimize his radiation exposure. However, this distance peer check was not approved by the shift manager or the control room supervisor. Step 5.2.2.4.7 of Procedure OP-100-001 precludes distance peer checks as a substitute for local peer checks if the task is a first time evolution for the performer, which was the case for both the positioner and the peer checker. The peer checker failed to recognize that the positioning NAO had not opened the correct valve, and agreed with the positioning NAO's report to the control room that Valve RC-10111 had been opened and that the vent path had been established. In actuality, Valve RC-10111 remained closed and the reactor vessel vent path remained isolated. This failure to follow procedure allowed the RCS to remain unvented during the subsequent RCS draindown, which caused the pressure in the RCS to drop below atmospheric.

Analysis. The failure to follow procedure while performing a peer check is a performance deficiency. The finding was more than minor because if left uncorrected it could have become a more safety significant concern and because it was associated with the human performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, "Shutdown Operations," Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available NPSH available to the operating SDC pumps at the low RCS pressure. The inspectors determined that the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps

In addition, this finding had crosscutting aspects associated with human performance for the failure to follow procedure.

Enforcement. Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, Revision 2. Regulatory Guide 1.33, Appendix A, Section 1, requires procedures be established, implemented, and maintained covering administrative processes for equipment control and safe operations. Contrary to this requirement, the NAO failed to implement Procedure OP-100-001, "Operation Standards and Management Expectations," steps 5.2.2.4.7 and -.8, by failing to provide an adequate local peer check for opening Valve RC-10111. This failure to provide an adequate local peer check allowed the RCS to remain unvented during subsequent draining of the RCS, which caused RCS pressure to remain below atmospheric. Because the failure to implement a required procedure was determined to be of very low safety significance and has been entered into the licensee's corrective action program as Condition Report CR-WF3-2005-1463, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000382/20050010-01; Failure to implement required procedure for peer checking.

.3 Introduction. A Green self-revealing noncited violation of Technical Specification 6.8.1.a was identified for failure to establish an adequate procedure that properly governed reactor coolant system inventory reductions.

Description. On April 18 and 19, 2005, NAOs were directed to establish vent paths for the RCS per Procedure OP-001-003, “RCS Drain Down.” The procedure directed that temporary vent rigs be installed at Valves RC-309 (pressurizer vent path) and RC-10111 (reactor vessel head vent path) and then directed that they be opened to establish their respective vent paths. However, Procedure OP-001-003 did not identify that both vent rigs include a ball valve in series with the vent path and did not identify that those ball valves also needed to be opened to establish the vent paths. This failure of the procedure to adequately control the configuration of the temporary vent rigs allowed the vent rig ball valves to remain closed and the RCS to remain unvented during subsequent draindown, which caused the pressure in the RCS to drop below atmospheric.

Although the temporary valves in the vent rigs were not addressed in Procedure OP-001-003, they were addressed in Procedure OP-001-001, “Reactor Coolant System Fill and Vent.” The fact that Procedure OP-001-003 did not address the vent rigs was identified in March 2002 and documented in Condition Report CR-WF3-2002-0491. However, the licensee decided not to add guidance to the procedure that addressed the ball valves. The issue was resolved with the following statement from the condition report, “Temporary valves are common on vent rigs and it is considered toolbox knowledge for an operator to manipulate this valve as required to perform the venting.” This was a missed opportunity to correct the procedural deficiency.

Analysis. The failure to establish an adequate procedure for RCS draindown is a performance deficiency. This finding was more than minor because if left uncorrected it could have become a more safety significant concern and because it was associated with the procedure quality attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, “Shutdown Operations,” Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available NPSH available to the operating SDC pumps at the low RCS pressure. The inspectors determined that the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps

This finding has crosscutting aspects associated with procedural quality and problem identification and resolution.

Enforcement. Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, Revision 2. Regulatory Guide 1.33, Appendix A, Section 3.a, requires procedures be established, implemented, and maintained with instructions for draining the RCS. Contrary to this requirement, Procedure OP-001-003, “RCS Drain Down,” was inadequate in that, although it governed the establishment of RCS vent paths necessary for RCS draindown by installing temporary vent rigs at Valves RC-309 (pressurizer vent path) and RC-10111 (reactor vessel head vent path), it did not identify that both vent rigs included a ball valve in series with the vent path and did not direct that those ball valves be opened to establish the vent path. This failure of the procedure to adequately control the configuration of the temporary vent rigs allowed the vent rig ball valves to remain closed and the RCS to remain unvented during subsequent draindown, which caused the pressure in the RCS to drop below atmospheric. Because the failure to establish an adequate procedure for draining the RCS was determined to be of very low safety significance and has been entered into the licensee’s corrective action program as Condition Report CR-WF3-2005-1463, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000382/20050010-02; Failure to establish an adequate procedure for draining the RCS.

.4 Introduction. An example of a Green self-revealing noncited violation of Technical Specification 6.8.1.a was identified for the failure to perform an adequate prejob brief. Specifically, the prejob brief provided to the NAOs responsible for establishing vent paths for the reactor vessel head and the pressurizer was inadequate because it did not cover all required material and because it did not ensure that the participants had the knowledge and information necessary to successfully perform the task.

Description. On April 18, 2005, operations conducted a prejob brief prior to draining the reactor coolant system. Administrative Procedure UNT-005-0027, “Infrequently Performed Tests or Evolution (IPTE),” Revision 2, identified Procedure OP-001-003, “Reactor Coolant System Drain Down,” as a procedure that required an IPTE brief. However, the NAOs that attempted to establish the pressurizer and reactor head vent paths did not receive an IPTE brief. The NAOs were performing other duties in the field. The control room supervisor recognized the NAOs were not briefed and intended to brief them separately, but the IPTE brief did not occur. However, the NAOs that attempted to establish the vent path did receive a separate brief from the work management center supervisor, but this brief was not performed in accordance with procedural requirements. A requirement of the IPTE brief was a discussion of prior operating experience. This discussion would have covered a 2002 event at Waterford in which the reactor vessel head vent path was not established prior to draining to RCS and would have addressed the vent rigs. Other industry operating experience would also have been covered during this brief.

Analysis. The performance deficiency was the failure to ensure that the prejob brief delivered the required knowledge and information needed for operators to successfully establish vent paths for the pressurizer and reactor vessel head. This finding was more than minor because it was associated with the procedure quality attribute of the initiating events cornerstone and affects the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, “Shutdown Operations,” Checklist 2.

Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available NPSH available to the operating SDC pumps at the low RCS pressure. The inspectors determined the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps

In addition, this finding had crosscutting aspects associated with human performance for the failure to follow procedure.

Enforcement. Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, Revision 2. Regulatory Guide 1.33, Appendix A, Section 1, requires procedures be established, implemented, and maintained covering administrative processes for safe operations. The inspectors reviewed Procedure OP-100-001, "Operations Standards and Management Expectations, Revision 20. Step 5.2.5.1 of this procedure stated, in part, that prejob briefs are performed to ensure that all participants have the knowledge and information necessary to perform successfully. Step 5.2.5.2 stated, in part, that pre-evolution briefings are performed for tasks or evolutions outside the routine operator rounds to ensure that all participants have the knowledge and information necessary to carry out the evolution successfully. Contrary to this, the NAOs that were assigned to establish the vent paths were not given, nor were they briefed on, the required information necessary to ensure the vent paths were established. The NAOs assigned to establish the vent paths had never received any physical training on how to properly establish vent paths and had never performed the evolution in the past. Failing to ensure that the prejob brief delivered the required knowledge and information needed for operators to successfully establish vent paths for the pressurizer and reactor vessel head was a violation. Because the failure to implement a required procedure was determined to be of very low safety significance and has been entered into the licensee's corrective action program as Condition Report CR-WF3- 2005-1463,this violation is being treated as a noncited violation consistent with Section VI.a of the NRC Enforcement Policy: NCV 05000382/2005/010-01; Failure to conduct an adequate prejob brief.

3.4 Evaluation of Pertinent Industry Operating Experience

a. Inspection Scope

The team reviewed Entergy's operating procedures, root cause evaluation report, and industry and government web sites for applicable operating experience and potential precursors to RCS inventory or vacuum problems or a loss of SDC similar to the Waterford 3 event on April 18-20, 2005. The team also reviewed Entergy's past and present actions to evaluate the effectiveness of their actions to preclude occurrence of a similar event.

b. Findings

No findings of significance were identified. The inspectors reviewed a March 2002 event, when Entergy created a partial vacuum in the reactor vessel, while performing a RCS draindown. Procedure OP-001-003, “Reactor Coolant System Drain Down,” directed operations to vent the reactor vessel head via Valves RC-101 (reactor vessel vent) or RC-10111 (reactor coolant isolation to reactor vessel vent line) if Valve RC-101 had been removed. Valves RC-101 and RC-10111 were located in series on the reactor vessel head vent line. Both Valves RC-101 and RC-10111 were installed; however, Valve RC-10111 had been deviated closed in accordance with another refueling procedure for reactor head removal preparations. This prevented the reactor head from venting. Procedure OP-001-003 did not reflect that configuration. To vent the reactor vessel head, Valves RC-101 and RC-10111 and the temporary rig ball valve must all be open. The cause of the partial vacuum condition was an inadequate procedure since the procedure did not explicitly indicate that Valve RC-10111 must always be open to vent the reactor head. Entergy changed Procedure OP-001-003 to require both Valves RC-101 and RC-10111 to be open to vent the reactor vessel head. However, the procedure was not changed to provide guidance for controlling the temporary vent rig ball valve. The operation of temporary vent rig valves was considered toolbox knowledge for operators. Since this was considered toolbox knowledge, procedural direction was not considered necessary. However, following the April 2005 partial vacuum event, Procedure OP-001-003 was subsequently revised to detail the reactor head vent with the temporary vent rig installed.

3.5 Evaluation of Adequacy of Operator Training and Knowledge for Draining the Pressurizer, Steam Generator, Transitioning to Reduced Inventory Operations, Activities While in Reduced Inventory/Midloop Operations, and other RCS Inventory Controls

a. Inspection Scope

The inspectors evaluated the training provided to licensed and nonlicensed operators for RCS inventory reduction and midloop operations to verify its adequacy.

b. Findings

Between April 18 and 19, 2005, three qualified NAO were involved in two instances of failing to establish an RCS vent path prior to draining the RCS. At 1 p.m., on April 18, two NAOs were dispatched to establish an RCS vent path via Valve RC-309, the pressurizer spray line vent valve, as required by Section 6.1.2 of Procedure OP-001-003, “RCS Drain Down.” A temporary vent rig with an in-line ball valve had been installed downstream of Valve RC-309, also as required by Procedure OP-001-003. However, neither the operating NAO nor the peer-checking NAO were familiar with the temporary vent rig (and the fact that it included an in-line ball valve) since it was a first time evolution for both NAOs. Procedure OP-001-003 required the vent path to be established through Valve RC-309 and the temporary vent rig downstream of Valve RC-309 and then removal of the hose on the vent rig after observing system response. (Typically a small amount of water issues from the vent rig, followed by the sound of air flow.) Neither NAO was aware of the expected system response and considered the vent path established after opening Valve RC-309, even though the ball valve in the vent rig remained shut and no vent path had been established.

Later during the draindown, at 6:11 a.m., on April 19, 2005, two NAOs (one of which was also involved in the Valve RC-309 operation) were dispatched to establish a second RCS vent path at Valve RC-10111, as required by Section 6.2.9.2.2 of Procedure OP-001-003, "Reactor Coolant System Drain Down." Similar to Valve RC-309, a temporary vent rig with an in-line ball valve had been installed downstream of Valve RC-10111, but neither the operating NAO nor the peer-checking NAO were familiar with the temporary vent rig (and the fact that it included an in-line ball valve), since it was a first time evolution for both. Additionally, neither NAO was familiar with the location of Valve RC-10111 (behind a removable shielding panel). As a result of their unfamiliarity with the location of Valve RC-10111 and the configuration of the temporary vent rig, both NAOs mistakenly identified the vent rig ball valve as Valve RC-10111, opened the vent rig ball valve, and left Valve RC-10111 closed.

In both instances, the NAOs involved were fully qualified, but had never before performed the operations with which they had been tasked. The ability to perform the valve operations required by an NAO during RCS draindown per Procedure OP-001-003 was identified in the licensee's job task analysis for the NAO. However, as documented in Section 3.3, the procedure was inadequate in that it failed to clearly identify that both vent rigs included a ball valve in series with the vent path and that the ball valves needed to be opened to establish the vent paths. An adequate procedure would have increased the likelihood that vent paths could have been properly established. Additionally, the inspectors evaluated records for the training received by the NAOs for properly establishing vent paths. The NAOs involved had received signatures for completing the training for this task by discussing the task with qualified NAOs, which was allowed, rather than by simulating or performing the task. However, there was no guidance for the level of detail required for task discussions. Although the training provided lacked specificity and detail, the inspectors concluded that, had the venting procedure been adequate, the NAOs possessed the necessary skill to perform the task.

3.6 Evaluation of the Response to the Misaligned Pressurizer and Reactor Vessel Vents, including the Impact on the RCS of a Sudden Pressurization of the RCS

a. Inspection Scope

The inspectors evaluated the licensee's response during the draindown, the controls in place to prevent entering reduced inventory, the licensee's inventory and pressure recovery plan, and an assessment of potential complications during the event.

b. Findings

The inspectors documented the numerous missed opportunities to identify the misaligned pressurizer and reactor vessel vents in Section 3.8 of this report.

The draindown procedure required the pressurizer manway be removed before draining below 18 feet (reduced inventory) to install the nozzle dams and it was the attempt to remove the manway that resulted in discovery of the RCS pressure condition. The lowest level reached during the draindown event was approximately18 feet 8 inches. Level indications remained accurate throughout the draindown event and it was concluded that entry into reduced inventory did not occur. Additionally, the Mansell level monitoring system was available. This system comes on-scale if level is drained below 18 feet. This system would have also alerted operators that the RCS was in a reduced inventory condition.

The vacuum condition was fully recognized at 3 a.m., on April 20 when the reactor vessel head and pressurizer vent paths were found to be closed. The shift manager immediately prohibited opening any vent, drain, or sample valve that could adversely affect the RCS. The licensee then developed a pressure and inventory recovery plan. The recovery plan involved slowly venting the pressurizer through the pressurizer spray vent rig, while using a charging pump to maintain RCS level between 20 and 24 feet. The 20 foot minimum was selected to ensure that SDC NPSH was not challenged. The 24 foot maximum level was selected to keep the Mansell level monitoring system and SDC vacuum priming in service. Procedure OP-001-003, “RCS Drain Down,” requires both systems to be removed from service above 24 feet RCS level. The licensee determined that the Mansell level monitoring system was the best available indication of RCS pressure under vacuum conditions. The inspectors evaluated this plan and the actions taken by operators during implementation of this plan. The inspectors concluded that the recovery plan was reasonable and that level and pressure were restored in accordance with the plan, without incident and undue risk.

The inspectors evaluated the effect that a rapid pressurization would have on the RCS. If a vent path were opened on the pressurizer or reactor vessel, there would have been a corresponding decrease in level. However, the total inventory in the RCS would have been maintained, and that would have resulted in a minimal affect on the NPSH available for the SDC pumps. Also water level would have maintained high enough in the hot leg such that no air ingestion into the SDC suction would have threatened to interrupt flow. At 3000 gpm, the margin to cavitation remained greater than 15 feet for each SDC pump. The inspectors concluded that adequate suction would have remained available to each SDC pump in the event of a sudden RCS pressurization.

3.7 Evaluations Performed to Assess Operability of the RCS and Attached Components (i.e., Level and Pressure Instrumentation, Reactor Coolant Pump Seal, etc.)

a. Inspection Scope

The inspectors reviewed the evaluations performed by the licensee to demonstrate that the RCS and attached components remained operable throughout the event while subjected to the vacuum condition.

b. Findings

The inspectors noted that several pressure indicators, with pressure ranges from 0-3000 psia were available during this event. The inspectors concluded that the indicators remained available and provided accurate pressure indications during the event.

With respect to the RCS operability, the inspectors reviewed the licensee's operability evaluation. The evaluation addressed reactor vessel internals, the pressurizer, the vessel head, RCS piping and valves, control element drive elements, reactor coolant pumps, instrumentation, fuel assemblies, and the potential for boric acid precipitation in the steam generators. The assessment concluded that the evaluated component remained operable. The inspectors agreed with this conclusion. However, the inspectors noted that the licensee did not evaluate the affect of the low RCS pressure on the diaphragm that was exposed to the full differential pressure when the pressurizer manway was removed. Therefore, the inspectors requested this evaluation. The licensee's subsequent evaluation assumed a perfect vacuum on the inside of the gasket retainer plate that was installed under the flange of the pressurizer manway. Calculated stress was 62 percent of the yield stress at 650EF and 37 percent of the yield stress at 100EF. Therefore the diaphragm was not overstressed. The inspectors agreed with this calculation.

The inspectors' initial review of other instrumentation raised several questions regarding instrumentation accuracy and applicability due to instrumentation location and the potential for trapped water or gas in high and low elevations in tubing. Specifics are addressed below.

3.7.1 Level Indications During the Event

Shutdown level indications are as follows:

Instrument	Description	Range	Reference Leg	Variable Leg
LT-103	Pressurizer Level Cold Cal. Display in control room on CP-2	0 - 100%	Pressurizer connection at EL 58.05 ft	Pressurizer connection at EL 27.8 ft
LG-107	RCSLMS Sight glass. Local indication inside containment.	12 - 30 ft	Temporary connection to pressurizer vent line	Temporary connection to bottom of hot leg

Instrument	Description	Range	Reference Leg	Variable Leg
LT-107-1 LT-107-2	RCSLMS Channels 1 & 2 Mandell Level Monitoring System. Display in control room on CP-2 and CP-8 and to Plant Monitoring Computer.	12 - 18 ft	"	Temporary connections to Hot Legs 1 & 2
LT-108	Transducer, RWLIS Narrow Range. Display in control room on CP-2 and CP-36 and provided to Plant Monitoring Computer.	12 - 16 ft	Permanent connection to top of condensate pot	Permanent connection to bottom of hot leg Number 1
LT-109	Transducer, RWLIS Wide Range. Display in control room on CP-2 and provided to Plant Monitoring Computer.	12 - 48 ft	"	"

Instruments LT-103, LG-107, and LT-109 were on-scale during the event. The LT-107s were operating and would have indicated level had it decreased below 18 feet.

Several indicators used the same connection at the bottom of the hot leg, Instruments LG-107 and LT-107 share the same reference leg, and Instruments LT-108 and LT-109 share the same reference leg. With the possible exception of the tubing connections within a foot or two of the instruments, the Instrument LT-107 and LG-107 reference legs are ensured to be gas-filled because any liquid will drain out of the reference leg via Instrument LG-107, the sight glass. This is not the case with the Instrument LT-108 and LT-109 connections to the top of the condensate pot.

The centerline of the condensing pots is located at the 58.05 foot elevation and the connection to the pressurizer was via a 3/4-inch horizontal line through a globe valve at this same elevation. (No slopes are indicated for these lines on the reviewed drawings and a walkdown was not practical since the plant was at full power during the inspection.) The inspectors concluded that the condensing pots appeared to provide an acceptable reference level for connections to the bottom of the pots, in part because of the apparent history of indication agreement and no evidence that water formed in the lines to cause erroneous indications.

The connecting tubing between RCS connections was specified to be sloped or vertical on all examined drawings with the following exceptions: (1) Tubing in cabinets appears to be horizontal and the horizontal lengths are of the order of a foot, and (2) long vertical tubing runs were provided with "U" sections to allow for differential expansion. The NRC concluded that it was unlikely that gas or liquid slugs would be formed in sufficient quantity to introduce an indication error.

Connections to the top of a condensate pot, as used for Instruments LT-108 and LT-109, do not use the pot level with respect to the reference leg. Procedure OP-001-003, “Reactor Coolant System Drain Down,” specified that the reactor water level indicating system (RWLIS) design limits are 100 psig and 250°F and a procedure was provided to drain the leg prior to making RWLIS operational. The inspectors concluded that this draining procedure would be effective provided conditions did not occur where condensation could take place on the instrument side of the highest level in the leg. The cooled condensation pot and initial portion of the reference leg would have likely removed most vapor before it reached a location where condensation would cause liquid to accumulate in the reference leg. Consequently, the NRC concluded the reference leg condition remained liquid-free during the event.

The potential for water traps close to the transmitters was addressed by Instrumentation Installation Drawing B430 General Notes I Revision 5, July 21, 2003, which states: "4. Instrument sensing lines to slope continuously toward the instrument when mounted below the process connection . . ." If installation was in accord with this note, then the above water trap concern would not apply.

Instrument tubing was exposed to the low pressure conditions. However, this tubing was at containment temperature and, in those cases where tubing was water filled, the combination of head of water and comparably low temperature would preclude flashing. The low pressure did not affect the water legs and the inspectors concluded that there would have been no impact on level indication.

The inspectors noted that Instruments LT-109 (RWLIS) and LG-107 (RCSLMS) agreed within approximately 0.1 ft on April 19 (Instruments LT-107 and LT-108 were off-scale at that time). Consequently, the inspectors concluded that accurate level indications were available during the event.

3.8 Review of Timeliness of Evaluations, Notifications, Appropriate Use of All Relevant Data, Procedure Usage, etc.

a. Inspection Scope

The inspectors reviewed the licensee’s timeliness of evaluations, notifications, and appropriate use of all relevant data and procedures in response to the RCS draindown activity. The team reviewed the licensee’s root cause analysis, draindown procedures, and corrective action documents, and interviewed operators and system engineers.

b. Findings

Introduction. A Green self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for failure to promptly identify and correct the vacuum condition in the RCS during draindown, a significant condition adverse to quality. This condition was created when vent paths were not established prior to draining the RCS. This resulted in a vacuum being drawn on the RCS for approximately 32 hours.

Description. On April 18, 2005, at 3 p.m., RCS draindown without an RCS vent path resulted in the indicated RCS pressure dropping below atmospheric. Operators in the control room failed to identify this condition at its inception and missed several other opportunities during the next 32 hours to identify and correct this adverse condition. The opportunities are outlined below.

The operators first noted that indicated pressure was lower than expected (between 9 and 11 psia) at 6:58 p.m., on April 18, 2005, but the operators believed that this indication was representative of atmospheric pressure with some allowance for instrument error on the wide-range transmitter (0-3000 psia). However, if the operators had utilized available computer trend data at this time, they could have observed that indicated pressure had tracked steadily down during the draindown between 3 p.m. and 6:58 p.m., which is not characteristic of draining the RCS while vented to atmosphere and indicates inadequate venting.

During continued draindown shortly after 5:01 a.m., on April 19, 2005, the operators noted that leakage from the RWSP to the RCS was occurring. The operators attributed this to known leakage past Valve SI-109A(B), LPSI Pump A(B) suction isolation valves. However, the leakage noted here and increasingly throughout the remainder of the draindown was higher than past experience indicated. This increased leakage rate was due to the increased differential pressure across the valves due to the vacuum drawn on the RCS. Although the operators took action to minimize the in-leakage from the RWSP by further tightening closed Valve SI-109A(B) and eventually closing Valve SI-106A, RWSP outlet isolation upstream of Valve SI-109A, they did not associate the increased in-leakage with already observed indications of a vacuum in the RCS.

At 9 a.m., on April 19, 2005, the operators observed that indicated RCS pressure was 6 psia. Operators directed a technician to check RCS pressure indication at a temporarily installed test instrument. The test instrument initially indicated 23 psia, which the operators believed to be suspect. After draining the instrument line, the test instrument indicated 15 psia, which the operators accepted as accurate and consistent with their belief that the RCS was adequately vented to atmosphere and should be at about 15 psia. The operators again failed to utilize computer trend data which showed that indicated RCS pressure had continued to trend downward while the RCS was being drained.

As RCS draindown continued, minor fluctuations in SDC pump flow and amps coincident with slight RCS temperature increases were observed at 11 a.m., and again at 1:30 p.m., on April 19, 2005. These indications were the result of flow oscillations induced in the suction piping of the SDC pumps as a result of achieving saturation conditions at the highest point in the SDC pump suction piping (some 58 feet above the actual pumps), saturation being achieved as the result of the vacuum condition in the RCS. However, the indications were attributed to SDC flow controller anomalies and operators did not associate these indications with the low indicated RCS pressure.

Additionally, these fluctuating SDC indications were identified as entry conditions for Off-Normal Procedure OP-901-131, “SDC Malfunction,” both in the off-normal and IPTE briefs for the Procedure OP-001-003 draindown. The operators chose not to enter the off-normal procedure because the indications observed were significantly smaller in magnitude than what simulator training and operational experience suggested was indicative of a loss of NPSH for SDC pumps and imminent loss of SDC. However, the combination of temperature rise, pump amperage variation, and flow oscillation did indicate possible cavitation in the SDC pump suction line, which would warrant entry into Procedure OP-901-131. Had the operators entered the off-normal procedure on suspected SDC pump cavitation, step 10 of Section E2 directed operators to “monitor RCS hot leg for saturation conditions.” This might have prompted the operators to re-evaluate the conditions in the RCS and recognize the vacuum condition at this point.

It was not until maintenance crews identified that they were unable to remove the pressurizer manway diaphragm at 11:30 p.m. on April 19, 2005, 32.5 hours after the first indication that a vacuum was being drawn in the RCS, that the operators began to realize that there may be a vacuum condition in the RCS. However, it wasn’t until 3 a.m. the following morning that further investigation confirmed that both vent paths that had been repeatedly reported as open were, in fact, isolated, at which time action was initiated to repressurize the RCS.

Analysis. The failure to promptly identify and correct the vacuum condition in the RCS during draindown, a significant condition adverse to quality, is a performance deficiency. This finding is more than minor because if left uncorrected it could have become a more safety significant concern and because it was associated with the human performance attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix G, “Shutdown Operations,” Checklist 2. Using the Phase 1 guidelines, the inspectors determined that the finding increased the likelihood that a loss of decay heat removal would occur due to a decrease in the available NPSH available to the operating SDC pumps at the low RCS pressure. The inspectors determined that the finding required a Phase 2 analysis and was sent to the regional Senior Reactor Analysts for risk quantification. The risk was determined to be of very low safety significance because, in this case, the reactor coolant system level was being administratively limited at a level where the system was not vulnerable to air binding the shutdown cooling pumps

This finding had crosscutting aspects associated with problem identification and resolution in that the RCS vacuum condition was unidentified for an extended period of time.

Enforcement. Criterion XVI of Appendix B of 10 CFR Part 50 states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this, established measures failed to assure that operators promptly identified and corrected the following adverse condition in the RCS: that the RCS had no vent path and that a vacuum had been drawn in the RCS lasting approximately 32.5 hours. Because the failure to promptly identify and correct the vacuum condition in the RCS was determined to be of very low safety significance and has been entered into the licensee's corrective action program as CR-WF3-2005-1463, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000382/20050010-03; Failure to promptly identify and correct the vacuum condition in the RCS.

3.9 Review of Root Cause Evaluation Determination for Independence, Completeness, and Accuracy

a. Inspection Scope

While in Mode 5 with SDC in operation, a partial vacuum was drawn on the RCS. The required pressurizer and reactor head vent paths were not open as expected. Entergy convened a significant event review team to initially develop recovery actions to restore atmospheric pressure in the RCS without challenging SDC and to verify RCS instrumentation was accurate and that the partial vacuum conditions were properly understood.

The inspectors gathered data and facts to assess the event's root causes and contributing causes, extent of condition, previous occurrence evaluation, equipment failure mechanisms, risk assessment, and the development of Entergy's corrective actions, including the corrective actions to prevent recurrence (CAPR). The inspectors reviewed: control room logs; plant operating parameters such as SDC system pressures, flow rates, pump motor current; reactor coolant pressure, temperature and level indications; and pressurizer temperature, level, and pressure instrumentation. The inspectors reviewed plant operating procedures and discussed event diagnosis and system recovery with the on-shift operations, maintenance, and engineering personnel, assessed human performance for the event, and the adequacy of station response to the RCS partial vacuum condition.

b. Findings and Observations

No findings of significance were identified. Overall, the licensee conducted a comprehensive review of the reactor coolant vacuum event on April 20, 2005. The inspectors noted that this event was classified as a significant adverse condition which required a detailed root cause investigation and development of corrective actions. Entergy conducted a comprehensive evaluation using an event and causal factor charting method and an organizational and programmatic weakness evaluation to identify the event's root and contributing causes.

The inspectors concluded that the licensee's root cause evaluation report, in general, adequately understood the conditions leading up to the event and the subsequent recovery actions, especially the challenge to continued operation of the SDC system, which was the most safety significant aspect of this event. Entergy concluded that the root causes of the event were associated with inadequate configuration control of vent rig valves in general, specifically the vent rig valves installed on the pressurizer and reactor vessel head, and the failure of a nuclear auxiliary operator to adequately self-check the manipulation of the appropriate reactor vessel head vent valve.

Additionally, Entergy identified several contributing causes that contributed to the RCS partial vacuum condition. Immediate actions, longer-term actions, and enhancement actions were taken to address the consequences of the RCS partial vacuum condition and prevent recurrence. Several of the corrective actions were CAPR. The CAPRs established programmatic and procedural controls over the use of temporary valves in vent and drain rigs, established required actions when a component lacks a component identification plate, and ensured that temporary installed valves are properly controlled in the station's temporary alteration procedure.

3.10 Review Evaluation of Tool Box Knowledge Issues and How the Determination is Made with Regard to Proceduralized Requirements Infrequently Performed and First Performed Evolutions

a. Inspection Scope

The inspectors reviewed Entergy's plan to reduce reliance on tool box knowledge by developing improved operating procedures for infrequently and first time performed tasks.

b. Findings

No findings of significance were identified. Toolbox knowledge is a collective term for operator training, prejob preparation, task-specific operational experience briefs and the use of human performance tools, such as: self-checking, peer-checking, challenging work assumptions, use of place keeping, a questioning attitude, effective communication techniques, prejob briefs, use of coaching, effective turnovers, and teamwork. The failure to perform nonprocedural actions properly contributed significantly to the RCS vacuum condition. Examples of toolbox knowledge barriers that failed include: (1) the prejob brief should have disclosed that it was a first time evolution for the operator who later failed to open the appropriate reactor head vent valve; (2) not all of the operators who were used in the field were at the prejob brief; (3) the specific job assignment for opening the reactor head vent valve was not assigned at the prejob brief; (4) the prejob brief should have discussed a previous failure to properly cycle the reactor head vent valve with all participants; and (5) an ineffective peer check resulted in opening the temporary vent gig valve installed downstream of Valve RC-10111. The inspectors documented several issues related to toolbox knowledge failures in Section 3.3.

Entergy's current strategy is to incorporate tool box knowledge into training and develop procedural improvements for enhanced rule-based decision making to reduce the reliance on the operator's skill and knowledge level. An example of Entergy's increased rule-based approach is that troubleshooting activities are no longer knowledge-based but rule-based. Entergy has developed several feedback loops designed to elicit comments from the individual worker to detail situations, conditions, or problems that would best be included in a work procedure. In general, Entergy specifies procedural direction when the action step requires knowledge that is not common to an operator who has completed formal training and has a minimum of one year's experience at his watch station.

While relying on knowledge and experience does not always lead to error, it is important that the worker recognize their vulnerability and stop work if necessary to seek clear and complete procedural guidance as appropriate. Entergy also intends to reduce errors by increased attention on training. The operator's formal training program includes site- and system-specific knowledge and the use of numerous human performance tools.

3.11 Review and Assess Corrective Actions and Ensure that They Have Adequately Evaluated and Addressed the Extent of Condition

a. Inspection Scope

The inspectors reviewed the licensee's immediate, interim, and long-term corrective actions associated with this event to determine if they were adequate to prevent a similar event. Specifically, the inspectors verified that root cause/contributing causes were appropriate, that the corrective actions had been properly prioritized, that a schedule for completion had been established, that an effectiveness review of the corrective actions was planned to be performed, and that the corrective action adequately addressed the extent of condition.

b. Findings

With respect to long-term corrective actions, the inspectors noted that the Operations Department was to perform a snapshot assessment in an attempt to identify other "toolbox knowledge" assumptions to either incorporate them into future training and/or develop procedural improvements to eliminate any inappropriate reliance on toolbox knowledge (Operational toolbox knowledge barrier failures are addressed in Section 3.10.) The due date for this assessment was July 29, 2005. However, no similar assessment was noted for maintenance. The root cause analysis identified the work orders that installed the vent rigs on the pressurizer and the reactor vessel head as inadequate because, although they were installed by maintenance, they did not specify the required configuration on the temporary vent rigs and did not provide administrative controls for the temporary ball valve that was installed. The vent rigs were installed using the toolbox knowledge of maintenance personnel. The inspectors concluded that the failure of the root cause analysis to specifically include maintenance personnel in the toolbox knowledge snapshot assessment was a missed opportunity to identify and incorporate other potential maintenance-related toolbox knowledge issues into procedures and/or training.

3.12 Review the Key Assumptions Used in the Licensee's Risk Analysis

a. Inspection Scope

The inspectors reviewed the licensee's key assumptions used to calculate the risk impact of this event in which a vacuum was drawn on the RCS while lowering level in the RCS. The conditions relevant to the risk assessment were: (1) RCS water level > 18 feet with both trains of SDC in operation. Although there were minor indications of LPSI pump cavitation, SDC was not lost; (2) RCS was closed with no vent path that could result in loss of inventory; (3) steam generator secondary filled with water and available as a heat removal path; (4) both HPSI pumps with suction from the RWSP were available, (5) motor-driven emergency feedwater pumps were available, and (6) both emergency diesel generators and offsite power were available.

To estimate core damage, the licensee assumed the following:

- Loss of SDC due to cavitation. This assumes both trains fail simultaneously. Probability of loss was assumed to be 0.1
- RCS makeup with high pressure safety injection fails
- Long-term reflux cooling via the steam generators fails
- With a loss of steam generator cooling, the RCS pressurizes to the low temperature overpressurization setpoint (415 psig)
- Primary inventory boiloff leads to core damage.

Based on key assumptions, the licensee calculated the risk associated with this event. Assuming the loss of SDC probability to be 0.1, the conditional core damage probability (from the shutdown risk model) was estimated to be 1.4E-7. The core damage risk was estimated to be 1.4E-8.

b. Findings

No findings of significance were identified.

3.13 Assess Any Other Issues Involving RCS Inventory Control During Refueling Outage 13 to Determine the Effectiveness of the Corrective Actions Taken

a. Inspection Scope

The inspectors assessed other draindown evolutions during Refueling Outage 13 to evaluate whether they were conducted in a controlled manner. The team reviewed the licensee's root cause analysis for the May 2005 containment integrated leak rate test (ILRT) event, ILRT procedures, corrective action documents, and Technical Specifications.

b. Findings

Introduction. A noncited violation of Technical Specification 6.8.1.a was identified for failure to establish an adequate procedure to govern the ILRT for the containment vessel.

Description. During the containment ILRT conducted May 20-22, 2005, it was discovered that an unexpectedly large void had formed in the reactor vessel head as a result of gas entrainment by the SDC pumps drawn in from Safety Injection Tank (SIT) 1A. Procedure PE-005-001, “Containment Integrated Leak Rate Test,” Revision 5, allowed Valve SI-331A, SIT 1A outlet isolation, to be open while the pressurizer level band was low enough that the water in the SIT 1A piping drains to its intersection with the RCS piping and thereby allows communication between the RCS flow and the air filled SIT 1A piping. This was the case during the ILRT and air became entrained in the RCS flow and then came out of solution in the reactor vessel head, forming a void in the upper head region. This failure of the ILRT procedure to prevent the combination of low pressurizer level with unisolated and vented SIT 1A caused an unexpected void to form in the reactor vessel head.

Due to air bubble that formed in the reactor vessel head more water was drained (~14,000 gallons) from the RCS that was put in during pressurization (~10,500 gallons).

Analysis. The failure of the ILRT procedure to prevent the plant configuration which led to void formation in the reactor vessel head is a performance deficiency. This finding was more than minor because it was associated with the configuration control attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. Attachment 1 of Appendix G of Manual Chapter 0609, “Significance Determination Process,” indicated no need for a Phase 2 analysis of the finding since adequate mitigation capability remained available. This finding has a human performance crosscutting aspect associated with procedure quality.

Enforcement. Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, Revision 2. Regulatory Guide 1.33, Appendix A, Section 8.b.1.a, requires procedures for containment leak rate tests. Contrary to this requirement, the procedure for ILRT was inadequate in that it did not prevent the combination of low pressurizer level with unisolated and vented Valve SIT 1A, causing an unexpected void to form in the reactor vessel head. Because the failure to establish an adequate procedure was determined to be of very low safety significance and has been entered into the licensee’s corrective program as Condition Report CR-WF3-2005-2461, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000382/20050010-04; Technical Specification 6.8.1.a violation for failure to establish an adequate procedure for containment ILRT.

4.0 **OTHER ACTIVITIES**

4OA2 Problem Identification and Resolution

Section 3.3.3 describes a finding that had crosscutting aspects associated with problem identification and resolution in that in March 2002 the licensee identified that the RCS draindown procedure did not address vent rigs. However, the licensee did not add guidance to the procedure that addressed the vent rigs. The licensee did not change the procedure because temporary valves were common on vent rigs and it was considered toolbox knowledge for operations to manipulate the valves as required to perform venting. This was a missed opportunity to correct the procedural deficiency.

Section 3.8 describes the licensee's failure to identify and correct the vacuum condition in the RCS in a timely manner. This condition was not identified even though there were multiple indicators that should have alerted operators that a vacuum had been drawn on the RCS.

4OA4 Crosscutting Aspects of Findings

Sections 3.3.1, 3.3.2, and 3.3.4 describe findings that had crosscutting aspects associated with human performance for failures to follow procedure.

Section 3.13 describes a finding that has human performance crosscutting aspects associated with procedure quality.

4OA6 Meetings

Exit Meeting Summary

.1 On June 20, 2005, the inspectors performed an inspection debrief and presented the inspection results to Mr. K. Walsh, Plant Manager, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

.2 On August 2, 2005, the inspectors discussed the inspection results with Mr. Alan Harris and other members of the staff who acknowledged the findings. The inspectors confirmed that propriety information was not provided or examined during the inspection.

.3 On September 14, 2005, Mr. D. N. Graves, Chief, Project Branch E, performed the final exit for this inspection and presented the inspection results to Mr. J. Venable and other members of your staff who acknowledged the findings.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

H. Broodt, Senior Lead Engineer
J. Burke, Supervisor, Quality Assurance
B. Fletcher, Manager, Training
C. Fugate, Assistant Manager, Operations
A. Harris, Director, NSA
J. Holman, Manager, Nuclear Engineering
J.Laque, Manager, Maintenance
N. Lawless, Site Coordinator, Human Performance
J. Lewis, Manager, Emergency Preparedness
R. Madjerich, Manager, Operations
G. Norris, Project Manager
O. Pipkins, Senior Engineer, Licensing
B. Proctor, Manager, System Engineering
R. Putnam, Supervision, System Engineering
J. Ridgel, Manager, Corrective Action
K. Walsh, Plant Manager
W. Wesley, Operations Training
A. Wemett, Assistance Operation Manager, Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

0500382/2005010-01	NCV	Failure to implement required procedure for RCS draindown (Section 3.3.b.1)
0500382/2005010-01	NCV	Failure to implement required procedure for peer-checking (Section 3.3.b.2)
0500382/2005010-02	NCV	Failure to establish an adequate procedure for reactor coolant system draindown (Section 3.3.b.3)
0500382/2005010-01	NCV	Failure to perform an adequate prejob brief prior to reducing level in the reactor coolant system (Section 3.3.b.4)
0500382/2005010-03	NCV	Failure to promptly identify and correct the vacuum condition in the reactor coolant system (Section 3.8)
0500382/2005010-04	NCV	Failure to establish an adequate procedure for performing the containment integrated leak rate test (Section 3.13)

LIST OF DOCUMENTS REVIEWED

Condition Reports

CR-WF3-2000-1509	CR-WF3-2002-0491	CR-WF3-2002-0496
CR-WF3-2003–0104	CR-WF3-2003-3984	CR-WF3-2005-2489
CR-WF3-2005-1143	CR-WF3-2005-1384	CR-WF3-2005-1453
CR-WF3-2005-1463	CR-WF3-2005-2461	

Procedures

NUMBER	TITLE	REVISION
OP-001-003	Reactor Coolant System Drain Down	22 and 23
OP-901-131	Shutdown Cooling Malfunction	2
OP-010-005	Plant Shutdown	4
OP-100-001	Operations Standards and Management Expectations	20
OP-010-006	Outage Operations	0
OP-010-005	Plant Shutdown	4
OP-001-001	Reactor Coolant System Fill and Vent	19
UNT-005-004	Temporary Alteration Control	6
UNT-005-027	Infrequently Performed Tests or Evolution	2
MA-101	Conduct of Maintenance	4
EN-LI-118	Root Cause Analysis Process	0
OI-034-000	Work Management Center	9

Miscellaneous Documents

NUMBER	TITLE/SUBJECT	REVISION
Information Notice 87-46	Undetected Loss of Reactor Coolant	
Generic Letter 88-17	Loss of Decay Heat Removal	

Miscellaneous Documents

NUMBER	TITLE/SUBJECT	REVISION
Information Notice 96-37	Inaccurate Reactor Water Level Indication and Inadvertent Drain Down During Shutdown	
Information Notice 93-12	Undetected Accumulation of Gas in Reactor Coolant System	
W3P88-3091	Generic Letter 88-17: Loss of Decay Heat Removal Response to Expeditious Actions	Dec. 23, 1988
W3P89-0101	Generic Letter 88-17: Loss of Decay Heat Removal Response to Programmed Enhancements	Feb. 1, 1989
W3P87-1775	Response to Generic Letter 88-17	Sept. 21, 1987
Generic Letter 87-12	Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) Is Partially Filled	
Calibration Data Package	RC IP0101B	7-9-1998
Drawing G-172	Flow Diagram Reactor Coolant System	32
WO 34550	Pzr Spray Line Vent Rig Installation	
WO 48724	Tagout for PZR Manway Removal	
WO 57341	RV Head Vent Rig Installation	

Other Documents

Drain Down to Midloop IPTE Briefing
Drain Down to Reduced Inventory IPTE
RCS Vacuum Removal IPTE

LIST OF ACRONYMS

CAPR	corrective action to prevent recurrence
I&C	instrumentation and control
ILRT	integrated leak rate test
IPTE	infrequently performed test or evolution
LPSI	low pressure safety injection
MSL	mean sea level
NAO	nuclear auxiliary operator
NPSH	net positive suction head
RCS	reactor coolant system
RCSLMS	reactor coolant system level monitoring system
RWLIS	reactor water level indicating system
RWSP	refueling water storage pool
SDC	shutdown cooling
SIT	safety injection tank

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

ENCLOSURE 2
June 2, 2005

MEMORANDUM TO: Vincent G. Gaddy, Senior Project Engineer, Project Branch E
Division of Reactor Projects

FROM: Arthur T. Howell III, Director, Division of Reactor Projects
/RA/ AVegel for

SUBJECT: CHARTER FOR THE SPECIAL INSPECTION TEAM AT THE WATERFORD 3 STEAM ELECTRIC STATION

Based on our initial evaluation of the safety significance associated with the April 20, 2005, reactor coolant system (RCS) configuration control issues that resulted in a vacuum being drawn in the RCS during a draindown evolution at the Waterford 3 Steam Electric Station, a Special Inspection Team is being chartered. You are hereby designated as the Special Inspection Team leader.

A. <u>Background</u>

On April 19, 2005, during the initial period of Refueling Outage 13, Entergy Operations was draining the RCS to 1.5 ft. below the reactor vessel flange (18.5 ft msl). Because of configuration control problems, the reactor vessel head vent and the pressurizer vent were both left in the closed position. With both these vent paths closed, a vacuum was drawn on the RCS. Entergy Operations' review identified that the pressure at the shutdown cooling (SDC) suction line at the hot leg connection to the RCS was approximately 5 psia. However, because the suction piping climbs to a higher elevation and there are numerous fittings and two gate valves, the pressure at this high point in the system decreased to approximately 1-2 psia with a corresponding saturation temperature of 105°F to 110°F (Saturation Temperature at 5 psia is 162°F). With pressure at 1-2 psia in the highest section of SDC piping, water flashed to vapor bubbles. As these vapor bubbles were pushed through the system, most of the bubbles collapsed as they reached sections of the system that were at a higher pressure, except for the noncondensable gases that had come out of solution. These bubbles were entrained in the flow and transported through the remainder of the suction side of the SDC system and traversed through the pumps.

Entergy Operations described the water and bubble solution as resembling an effervescent condition, although this has not been demonstrated to the NRC. This condition reduced the specific gravity of the water and subsequently the net positive suction head (NPSH) (available) at the pump suction. A review of the chart recorders showed that the pump motor amps oscillated (4 to 5 amps peak to peak) and coolant flow indications fluctuated approximately (400 gpm). In addition, the SDC flow control valves, which were in automatic, began to oscillate to compensate for the drop in flow conditions in the SDC system. Entergy Operations at this time was not aware of the vacuum conditions in the RCS and of the coolant flashing created by these conditions. When Entergy Operations saw the first indications (motor amp fluctuations, SDC flow fluctuations, and SDC flow control valve fluctuations), they took manual control of the SDC flow control valves, and system conditions appeared to stabilize. Since no other indications were available to indicate a problem with the SDC system, Entergy Operations returned the flow control valves to automatic with RCS vessel level indicating between 20' msl and 18' 6" msl. Approximately 3.5 hours later, Entergy Operations saw a repeat of the conditions previously described and again took manual control of the SDC flow control valves to stop the draindown of the RCS. The RCS level was maintained at approximately 18' 6" msl as prescribed by their procedure to facilitate removal of the pressurizer manway. Subsequently, the vacuum conditions in the RCS were identified when an attempt was made to remove the pressurizer manway diaphragm.

Entergy Operations maintained that this condition seen throughout this event would not have led to the loss of SDC and that there were two trains of high pressure safety injection available with suction from the refueling water storage pool (RWSP), as well as one charging pump train with suction from the boric acid makeup tank (BAMT) to ensure makeup water to the RCS. The safety injection tanks could have been aligned to the RCS within 15 minutes if needed and both emergency diesel generators were available along with offsite power. Entergy Operations indicated that, since no vent path was available, there would be no path for loss of RCS inventory.

B. Basis

The initial review of this event identified concerns with operation of the facility that exceeded, or were not included in, the design basis of the facility, involved significant unexpected system interactions, and involved questions or concerns pertaining to licensee operational performance.

The RCS was operated under vacuum conditions that were not specifically analyzed in the design basis of the facility. The effect of these conditions on equipment and instrumentation will be reviewed as apart of the special inspection. Vacuum in the RCS (less than 5 psi absolute) resulted in coolant flashing and the creation of bubbles of noncondensable gasses which passed through the SDC pumps. The vacuum conditions were the result of apparent human performance problems that resulted in both the reactor vessel vent and pressurizer vent not being opened before beginning the RCS draindown. A similar configuration control problem occurred two refueling outages earlier that resulted in one of the vent valves also being left closed.

Risk assessments performed by NRC reactor analysts provided an incremental conditional core damage probability within the special inspection range identified in Management Directive 8.3, NRC Incident Investigation Program.

C. Scope

The team is expected to perform data gathering and fact-finding in order to address the following items:

- Develop a complete sequence of events involving preparation for the reduction in RCS inventory, Entergy's actions while the condition existed, and recovery.

- Evaluate the conditions that existed in the RCS for temperatures, pressures, and water inventories.

- Assess the controls that were in place for establishing adequate vent paths for initial RCS inventory reduction and reduced/midloop operations.

- Evaluate pertinent industry operating experience and potential precursors to the condition, including the effectiveness of any actions taken in response to the operating experience. Also review corrective actions from any prior similar events.

- Identify and develop any areas for generic communication involving this event.

- Evaluate the adequacy of operator training and knowledge for draining the pressurizer, steam generators, transitioning to reduced inventory operations, activities while in reduced inventory/midloop operations, and other RCS inventory controls.

- Evaluate the adequacy of Entergy's response to the misaligned pressurizer and reactor vessel vents, including the impact on the RCS of a sudden pressurization of the RCS.

- Determine what evaluations were performed to assess operability of RCS and attached components (i.e., level and pressure instrumentation, reactor coolant pump seals, etc.).

- Review the timeliness of evaluations, notifications, appropriate use of all relevant data, procedure usage, etc.

- Review Entergy's root cause evaluation determination for independence, completeness, and accuracy, including the risk analysis of the event.

- Review Entergy's evaluation of tool box knowledge issues and how the determination is made with regard to proceduralized requirements for infrequently performed and first time performed evolutions.

- Review and assess Entergy's corrective actions and ensure that they have adequately evaluated and addressed the extent of condition.

- Review the key risk assumptions as used in the licensee's risk analysis.

- C Assess any other issues involving reactor coolant system inventory control during RF-13 to determine the effectiveness of the corrective actions taken.

C. Guidance

Inspection Procedure 93812, "Special Inspection," dated July 7, 2003, provides additional guidance to be used by the Special Inspection Team.

This memorandum designates you as the Special Inspection Team leader. Your duties are described in Inspection Procedure 93812. The team composition will consist of yourself, Messrs. Grant Larkin (Resident Inspector), Mark Haire (Operations Engineer), and an NRR representative. During performance of the special inspection, the designated team members are separated from normal duties and report directly to you. The team is to emphasize fact-finding in its review of the circumstances surrounding the event, and it is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The Team will report to the site, conduct an entrance, and begin inspection on June 20, 2005. Tentatively, the inspection should be completed by the close of business on June 23, 2005. A formal exit will be scheduled following completion of the on-site inspection. A report documenting the results of the inspection will be issued within 30 days of the completion of the inspection. While the team is onsite, you will provide daily status briefings to Region IV management.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact Mr. David Graves at (817) 860-8141.

cc via e-mail:

REGION IV

B. Mallett	J. Dixon-Herrity, OEDO
T. Gwynn	H. Berkow, NRR
D. Chamberlain	M. Webb, NRR
A. Howell	N. Kalyanam, NRR
A. Vegel	
D. Graves	
A. Gody	
J. Clark	
W. Jones	
D. Powers	
V. Gaddy	
M. Hay	
G. Larkin	
J. Kirkland	
D. Loveless	
M. Runyan	
R. Bywater	

SEQUENCE OF EVENTS

Date/Time	Events/Comments
4/18/05 01:18	Secured RCP 2A
4/18/05 01:19	Secured RCP 1A
4/18/05 04:26	Completed collapsing pressurizer bubble
4/18/05 04:30	Filled SGs 1 and 2 to 80 percent narrow range
4/18/05 05:33	Secured pressurizer steam space alignment to volume control tank
4/18/05 09:25	Closed SI-109B, “LPSI Pump Suction Isolation Valve”
4/18/05 09:40	Closed SI-109A, “LPSI Pump Suction Isolation Valve”
4/18/05 10:28	Depressurized the RCS to atmosphere and secured letdown
4/18/05 10:41	Train B shutdown cooling purification in service
4/18/05 12:50	Temporary vent rig placed on RC-309 (Pressurizer Spray Line Vent Valve).
4/18/05 13:00 approximate	Nuclear auxiliary operator reports that RC-309 is open and hose is removed
4/18/05 13:30	Infrequently Performed Test or Evolution (IPTE) brief for draining the RCS below 5 percent cold cal pressurizer level completed for day shift
4/18/05 14:57	Commenced draining pressurizer to 10-20 percent level cold cal
4/18/05 1500	A post review of archived PMC data using PI shows that as the draining of the RCS proceeded, wide range pressurizer pressure began to slowly drop, and at about 1500 it indicated RCS pressure dropped below atmospheric
4/18/05 17:00	Hung danger tag on RC-309. Valve required to be open as a vent path for the RCS. Nuclear auxiliary operators verify valve open.
4/18/05 18:00 approximate	Temporary vent rig installed at reactor head vent flange. Temporary rig installed with its valve closed.
4/18/05 18:58	Suspended draining pressurizer, level 26 percent cold cal
4/18/05 20:00	Night crew completed their IPTE brief for draindown
4/19/05 00:00	RCS pressure = 8 psia, Temp = 115 F
4/19/05 00:57	Aligned HPSI pump AB for operation with HPSI pump B (Modes 5&6)

Date/Time	Events/Comments
4/19/05 02:04	Recommenced RCS draindown to hold up Tank D per Procedure OP-010-005, “Plant Shutdown”
4/19/05 04:37	Pressurizer level 7.6 percent cold cal, hold up Tank D = 44.125 percent, RWLIS = 29.962 percent, Sightglass = 29.9 feet transitioning to OP-010-003 for draindown to 24 feet
4/19/05 04:55	Secured draining RCS. Pressurizer = 5 percent cold cal
4/19/05 05:01	Commenced draining to 24 feet per Procedure OP-001-003,” Plant Shutdown”
4/09/05 06:11	NAOs directed to vent reactor vessel head by opening RC-10111. RC-10111 independently verified open
4/19/05 06:25	RCS at 24 feet
4/19/05 07:44	Closed 2 additional turns on SI-109A and 3 on SI-109B. Operator begin to question pressure indications
4/19/05 09:00	Operators direct I&C to enter containment and check actual RCS pressure using a temporarily installed test instrument. Initial pressure reading was 23 psia. Drained instrument and pressure rechecked. Pressure measured to be 15 psia. Operators believed pressure was at the required atmospheric conditions.
4/19/05 09:37	Obtained permission from Assistant Operation Manager to drain Refueling Water Storage Pool
4/19/05 11:00	While draining to 18.5 feet, operations noted a temperature rise of about 7 F in the shutdown cooling system. Draining was secured. During subsequent evaluation, fluctuations up to 700 gpm were noted in the flow controller output for the shutdown cooling train A Flow Control Valve, SI-129A.
4/19/05 11:00 approximate	SI-129A taken to manual. I&C technician sent to look at the controller. No problems were found with the controller. Operators conclude entry conditions for Off-Normal Operating Procedure OP-901-131 were not met. Draining recommenced.
4/19/05 13:30	Another similar temperature rise occurred. Flow controllers on both trains were fluctuating. Both flow controllers placed in manual and flow and temperature stabilized.
4/19/05 14:07	Placed shutdown cooling purification in service on shutdown cooling Train B
4/19/05 16:00	Shutdown cooling flow reduced 1000 gpm to 3000gpm. No further problems were noted with shutdown cooling flow.

Date/Time	Events/Comments
4/19/05 17:13	Commenced RCS draindown to the RWSP per Procedure OP-001-003, “Reactor Coolant System Drain Down”
4/19/05 17:32	Secured draining the RCS to the RWSP. RCS level =19.1 feet
4/19/05 21:20	Opened knife switch for HPSI Pump A due to SI-106A (Trn A Outlet from RWSP) being closed to minimize leakage into the RCS
4/19/05 22:02	Commenced draining the RCS (20.1 feet) to the RWSP
4/19/05 22:30	Secured draining the RCS (18.97 feet) to the RWSP
4/19/05 23:00	Mechanical maintenance began to unbolt and remove pressurizer manway cover per procedure. Required for steam generator nozzle dam installation
4/19/05 23:30	Mechanical maintenance determine pressurizer manway diaphragm could not be removed. Control room staff notified shortly thereafter of a partial vacuum condition in the RCS
4/19/05 23:57	RCS level rise of approximately 0.15 feet
4/20/05 00:30	Determined that there was a closed ball valve with no handle in the spool piece at RC-309
4/20/05 03:00	Determined that RC-10111, “Reactor Coolant Isolation to Reactor Vessel Vent Line,” was closed
4/20/05 03:27	Started seal package for charging Pump A in preparation for raising RCS level
4/20/05 05:25	Performed brief for OP-901-131, “Shutdown Cooling Malfunction”
4/20/05 09:30	Obtained Assistant Operations Manager permission to drain the RCS to RWSP
4/20/05 10:19	Started charging Pump A and commenced filling RCS from RWSP per OP-001-003. Initial level 21.69 feet
4/20/05 11:01	Secured charging Pump A. Final level 23 feet
4/20/05 14:37	Commenced draining the RCS to the RWSP per OP-001-003. Initial RCS level 24 feet
4/20/05 14:59	Secured draining the RCS to the RWSP. Final RCS level 22.13 feet
4/20/05 21:05	Completed IPTE brief for Procedure OP-001-003, “Reactor Coolant System Vacuum Removal”
4/20/05 22:09	Commenced venting for RCS partial vacuum removal per OP-001-003

Date/Time	Events/Comments
4/21/05 0645	RCS was returned to atmospheric pressure by alternately venting at the RC-309 vent rig and raising pressurizer level using a charging pump, maintaining a 20-24 foot level band.