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Audit of Oconee Procedures and Training for Pressurized Thermal Shock

CONTENTS

1 INTRODUCTION

1.1 Short-Term Objectives and Scope of Review

On May 11, 1982, an interdisciplinary audit team visited Oconee Nuclear Station to evaluate certain aspects of the Pressurized Thermal Shock (PTS) issue. The question that the audit team focused on was:

> ARE CORRECTIVE ACTIONS REQUIRED THAT MUST BE INITIATED BEFORE THE LONGER TERM PTS PROGRAM PROVIDES GENERIC RESOLUTION AND ACCEPTANCE CRITERIA?

Emergency procedures and operator training were the only areas in which the Oconee audit team applied the above general question. As noted in the NRR March 9, 1982 presentation to the Commission:

> "...we will undertake a program to verify that existing operating procedures contain the steps necessary to prevent and/or mitigate PTS events, and to verify that operator education/training programs regarding PTS are acceptably thorough."

Due to the limitation of the review to training and procedures, the resolution of various technical questions on PTS (thermal-hydraulic analyses, fracture mechanics, probabilities) was not part of the audit team charter. Also, implementation of any recommendations (see Section 4) is subject to coordination and consistency with the longer term generic program (USI A--49).

A visit to Oconee took place on May 11-14 1982, during which time the audit team evaluated procedures and training. The key findings of the group are discussed in Section 3. In preparation for the Oconee audit the audit team used the general criteria addressed in Section 2.

1.2 Current Status of the Generic PTS Issue

Efforts to pursue an integrated PTS program involving a variety of technical areas are continuing under USI A-49. The summer of 1983 is the current schedule for finalizing the generic regulatory requirements for PTS along with required corrective actions if the generic requirements are not met. Key issues are yet to be resolved and extensive programs exist to provide the foundation for the generic regulatory requirements.

Before the above effort resulting in regulatory requirements is

completed however, the staff has committed to the Commission to have developed an interim initial position for the summer of 1982 (June). The interim initial position will consist of NRC evaluation of the safety of continued plant operation (and initial corrective actions required) for the eight plants previously identified as representative of plants having the highest RTNDT. Technical assistance is being provided by a PNL multi-disciplinary team. PNL has been contracted to work with the staff to provide recommendations regarding the June 1982 initial position on the safety of continued operation and to recommend any additional corrective actions that PNL believes should be initiated before the NRC generic resolution and acceptance criteria are adopted. The June recommendations by the NRC staff to the Commission will also consider the findings and recommendations addressed in Sections 3 and 4 of this report, as well as other audit teams formed for related investigations (such as fluence reduction at the vessel wall).

1.3 Oconee Configuration

The Oconee Nuclear Station is a three unit 2568 MWt B&W lowered loop design. The Reactor Coolant System (RCS) configuration is a two-loop, four cold leg design utilizing the B&W once-through steam generator (OTSG). Plant control is by the integrated Control System (ICS), which matches reactor power and feedwater flow to the electrical generation demand. Plant transients are mitigated by the Reactor

Protective System (RPS) and the Engineered Safety Feature System (ESFS) which, if necessary, actuates the Emergency Core Cooling System (ECCS) for long term core subcriticality and decay heat removal.

The ECCS includes the High Pressure Injection System (HPIS), the passive Core Flood Tank System (CFTS), and the Low Pressure Injection System (LPIS). The HPIS, which also provides reactor coolant pump seal injection and normal makeup and letdown control, consists of three pumps injecting into four cold leg locations. The HPI pumps are actuated on low RCS pressure at 1500 psig. Two of the three pumps are normally aligned to the A loop. The two passive CFT's have a liquid volume of 1010 ft(3) each and inject through two core flood lines to the reactor vessel downcomer. Injection begins when the RCS pressure decreases below the 600 psig nitrogen overpressure in the tank. The LPIS consists of two pumps that are actuated on low RCS pressure at 500 psig and inject through the core flood lines to the reactor vessel downcomer. Although the LPIS is actuated at 500 psig, the pump shutoff head prevents injection until the RCS pressure decreases below 200 psig, so that the LPI is not functional for non-LOCA transients. RCS pressure control is accomplished by the pressurizer spray (200 gpm), the pressurizer heaters (1638 kW), the pressurizer relief valve (1-3/32 inch ID), and two pressurizer safety valves (1-4/5 inch ID).

Feedwater is delivered from the condenser hotwell to the steam generators by three hotwell pumps, three condensate booster pumps, and

two turbine-driven main feedwater pumps. A closed secondary cycle of two trains of six stages of feedwater heaters is utilized. The Emergency Feedwater System (EFWS) consists of two motor-driven and one turbine-driven pump. One motor-driven pump is dedicated to each steam generator and the turbine-driven pump is shared. Steam generator pressure control is performed by the Turbine Bypass System (TBS), which is part of the ICS, and the main steam code safety relief valves. Each steam generator is equipped with two turbine bypass valves with 12.5% total steam relief capacity, and eight safety valves with 58.5% total steam relief capacity.

The Oconee Nuclear Station has two control rooms. One control room contains the controls/displays for Units 1 and 2, while the second control room contains the control/displays for Unit 3 only. The former control room is U-shaped. Half of the "U" provides the controls/displays for Unit 1, while the other half, which is essentially a mirror image, provides the controls/displays for Unit 2. Back panels are located behind the open portion of the "U". The following table contains the major parameters available to an operator at Oconee that would assist in monitoring PTS events:

Parameters	Display
RCS Pressure	Wide- and narrow-range meters and digital readout

RCS Temperature	T-hot had a narrow-range meter and a narrow-range strip recorder. T-cold had a wide-range meter and wide-range strip recorder. These temperatures could also be read on a CRT
In-Core Temperature	Read on a CRT with back-up voltage readings from a back panel. Voltages are converted to temperature using graph contained in a procedure
Subcooling Margin	Digital readout showing subcooling margin for T-hot, T-cold, and RPV in-core temperature
Cooldown Rate	Instantaneous cooldown rate is provided on the CRT

2 SHORT-TERM CRITERIA USED FOR OCONEE AUDIT

2.1 Transient and Accident Analyses

2.1.1 Introduction

Overcooling events in PWRs may occur as a result of steam line breaks (excessive steam flow), feedwater system malfunctions, or loss-of-coolant accidents. Multiple failures and/or operator errors can result in more severe overcooling events. Of particular concern are those events in which repressurization of the primary system occurs following the severe overcooling. This section addresses an overview of Oconee Units 1,2, and 3 overcooling events that occurred since the plant was built. Aside from the primary mission of the audit team to examine procedures and training, also provided (Section 2.1.4) is a summary of the thermal-hydraulic analyses available for evaluating pressurized thermal shock events.

Section 3.1 provides our comments and conclusions on these events and analyses.

2.1.2 Oconee Overcooling Events Summary

A detailed review of the operating history of Oconee has resulted in the identification of events that have resulted in exceeding the

cooldown rate limit of 100 F/hr, as well as identifying those events that could have led to exceeding the cooldown rate limit if not mitigated by automatic plant controls and protective functions or operator action.

2.1.2.1 Event 1: Unit 1 - May 5, 1973

This event occurred during pre-commercial testing and includes several system responses and operator actions which are atypical of current operation. From an initial power level of 18%, a control system (CS) upset resulted in a trip of both MFW pumps. A manual trip of the reactor followed at 30 seconds. The turbine bypass system (TBS) on steam generator (SG) A was in manual due to controller problems and SG B was in automatic pressure control. Since TB valves on SG A remained partially open following reactor trip on loss of feedwater, SG A essentially boiled dry. Both SG pressures decreased to 700 psig. The EFW pump (only one turbine-driven pump at this time) was not in automatic control and did not start. Three minutes after trip the main feedwater system (MFWS) was manually restored and an overfeed of both SG's occurred. The combination of low SG pressure and overfeed, along with a low decay heat level, resulted in a minimum RCS pressure of 1330 psig, and a minimum temperature of approximately 500 F. The normal post-trip temperature is 550 F. System conditions stabilized within 15 minutes.

2.1.2.2 Event 2: Unit 2 - January 4, 1974

A loss of offsite power from an initial power level of 75% resulted in a reactor trip, RC pump trip, and MFW pump trip. The EFW pump (one turbine-driven pump) initiated fill of the SG's to 95% SG level as originally designed for natural circulation. An auxiliary steam demand of 80,000 lb/hr was being supplied to the auxiliary steam header. These conditions caused reductions in T-cold(A) from 562 F to 422 F, and T-cold(B) from 562 F to 426.5 F in the first hour. These are cooldown rates of 140 F/hr and 135.5 F/hr respectively. This transient was the first operational occurrence of natural circulation in a B&W plant. The excessive cooldown rates necessitated a reduction in the natural circulation setpoint from 95% to 50% on the steam generator level operating range.

2.1.2.3 Event 3: Unit 2 - July 11, 1974

A loss of ICS power from an initial power level of 80% resulted in a reactor trip and a loss of normal feedwater control whereby feedwater was delivered through both the main and auxiliary feedwater headers. In addition, the pressurizer relief valve apparently failed open on the loss of ICS power. This is not the current failure mode, which is to fail closed on loss of ICS power. Approximately 20 to 30 seconds following trip, the system had depressurized to 1550 psig and the HPIS was actuated. ICS power was manually restored in 30 to 45 seconds and

the system returned to normal pressure within 3 to 4 minutes. The minimum RCS temperature was 515 F, and the minimum pressure 1450 psig.

2.1.2.4 Event 4: Unit 2 - September 10, 1974

From an initial power level of 80%, a partial failure of the turbine header pressure signal to the ICS caused the TB valves on SG A to fail open. The ICS responded to the reduction in electrical generation by withdrawing rods to meet the megawatt demand. The operator was alerted to the situation and, after identifying that the TB valves were functioning incorrectly, manually isolated the valves. The faulty electronic component was replaced and the TBS returned to a small increase in reactor power. The unit remained on line.

2.1.2.5 Event 5: Unit 2 - September 17, 1974

Following a reactor trip from 100% power, the ICS did not successfully run back feedwater. The moderate overfeed resulted in a high SG level trip of both MFW pumps at 220 seconds. The EFW pump (one turbine-driven pump) was actuated. The transient resulted in a minimum RCS temperature of 547 F, and a minimum pressure of 1700 psig.

2.1.2.6 Event 6: Unit 2 - March 7, 1975

At an initial power level of 15%, feedwater control began the normal switch from the startup control valve to the main control valve. As the B main block valve opened, an overfeed of SG B occurred which was terminated by the high SG level trip of the MFW pump. RCS pressure decreased to 1925 psig, at which time the operator manually tripped the reactor. The subsequent investigation identified that the MFW control valve B was stuck open. The valve was repaired. The RCS temperature decreased only slightly.

2.1.2.7 Event 7: Unit 3 - April 30, 1975

During a loss of load test from 100% power, the ICS runback of main feedwater was too slow and resulted in a high SG level trip of both MFW pumps. In addition, one main steam code safety valve did not reseat until 850 psig (normal reseat pressure 1000 psig). RCS pressure decreased to 1575 psig, and a minimum temperature of 540 F resulted.

2.1.2.8 Event 8: Unit 3 - May 25, 1975

From an initial power level of 100%, a blown fuse in the power supply to a solenoid valve on the air supply to the TB valves on SG A resulted in the valves failing open. The ICS responded by increasing

feedwater flow and withdrawing rods. The reduction in T-ave resulted in an increase in reactor power, and a trip on high flux occurred. The turbine bypass valves were isolated at approximately 20-25 minutes following trip. Pressurizer level decreased to 25 inches, and the resulting minimum temperature was 485 F.

2.1.2.9 Event 9: Unit 3 - June 13, 1975

During a normal shutdown from 100% power, an RCS pressure spike occurred at 19% power due to manual pressure control of the SG's. The pressurizer relief valve opened at 2267 psig and failed to reseat. The reactor tripped on low RCS pressure 80 seconds later. HPI was actuated on low RCS pressure at 1500 psig 209 seconds after the relief valve failed, the block valve was manually closed 25 minutes following relief valve failure, and the RCS pressure bottomed out at 720 psig. The transient was under control 28 minutes after relief valve failure with the RCS temperature at 510 F. A normal cooldown then followed.

2.1.2.10 Event 10: Unit 3 - July 13, 1975

From an initial power level of 80%, a transistor failure in the TBS caused the TB valves on SG B to fail open. The ICS responded by withdrawing rods. Reactor power increased in response to the rod motion and the decrease in T-ave. The operator promptly identified the open TB valves and manually isolated them. The unit remained on

line.

2.1.2.11 Event 11: Unit 1 - August 14, 1976

During three pump operation at 75% power, an asymmetric rod position alarm initiated a runback of 60% power. Soon afterward, control rod group 6 dropped into the core due to a rod drive problem. The operator assumed manual control of feedwater during the ensuing power increase. Difficulty with feedwater in manual control resulted in an overfeed of SG A, and tripped the MFW pumps and the turbine. The reactor subsequently tripped on high pressure. No cooldown occurred.

2.1.2.12 Event 12: Unit 1 - December 14, 1978

From an initial power level of 98%, a short in the ICS T-ave recorder incorrectly transmitted a low T-ave signal resulting in rod withdrawal. The operator noticed power increasing and assumed manual rod control. With T-ave control by rods defeated, the ICS transferred T-ave control to the MFWS which resulted in a reduction in feedwater flow. The operator recognized T-hot increasing with decreasing feedwater flow and assumed manual control of feedwater. The reactor tripped on high temperature. Feedwater was increased rapidly, and the resulting high discharge pressure tripped both pumps. The EFW pump (one turbine-driven pump) was actuated 7 seconds later, and was stopped 21 seconds later when the MFW pumps were reset and started.

SG levels continued to decrease until SG A reached 6 inches and SG B boiled dry. Recognizing the loss of SG level, the operators proceeded to feed both SG's through the auxiliary headers, and restore SG A to 80 inches and SG B to 30 inches. The EFW pump was started to help feed SG B. In response to the refilling of the SG's, RCS pressure rapidly decreased resulting in HPIS actuation and a minimum pressure of 1450 psig. Both MFW pumps then tripped on low vacuum, and the EFW pump was then aligned to feed both SG's. RCS temperature reached a minimum of 500 F.

2.1.2.13 Event 13: Unit 3 - November 10, 1979

From an initial power level of 99%, a false signal tripped the hotwell pumps which tripped one of the three condensate booster pumps. This initiated a reactor runback on low feedwater flow. The runback was unsuccessful, and the reactor tripped on high pressure at 55 seconds. A loss of ICS power occurred at 115 seconds. This resulted in a trip of both MFW pumps, and actuation of all three EFW pumps. The loss of ICS power caused an extensive loss of instrumentation. RCS wide range pressure was unaffected. All three HPI pumps were put in operation. ICS power was restored at 223 seconds. At that time RCS pressure was 1675 psig and increasing, and pressurizer level was 20 inches and increasing. The RCS temperature was 525 F. On restoration of ICS power, the TB valves partially opened. Auxiliary steam was being supplied from this unit at that time. Both SG's were near boiled dry

conditions. Approximately 10 minutes after transient initiation, the level in SG B increased abruptly following startup of one hotwell pump and one booster pump. SG pressure was 400 psig. As a result of these steam generator conditions, the RCS temperature decreased to 420 F in 20 minutes. This is a cooldown of 115 F, which exceeds the cooldown limit of 100 F/hr. At 31 minutes following transient initiation, the auxiliary steam flowpath and the TB valves were isolated. A return to hot shutdown conditions proceeded normally.

2.1.2.14 Event 14: Unit 2 - January 30, 1980

Following a reactor trip from 89% power, the operator recognized that the ICS was not decreasing feedwater flow rapidly enough, as indicated by SG level. Although manual control of feedwater was attempted, a high SG level trip of both MFW pumps occurred. The RCS temperature decreased to 540 F.

2.1.2.15 Event 15: Unit 3 - March 14, 1980

Following a reactor trip from 100% power, the ICS failed to runback feedwater as designed due to a wiring problem and calibration error. The subsequent overfeed of SG A tripped both MFW pumps on high SG level. The RCS temperature decreased to 546 F.

2.1.2.16 Event 16: Unit 1 - May 4, 1981

From an initial power level of 100%, the SG A pressure input to the ICS drifted high causing the TB valves on SG A to open. The resulting steam leak caused a 12.5% decrease in electrical generation. The ICS responded by withdrawing rods until inhibited by high flux at 103% power. The unit remained on line. RCS temperature decreased by 4 F.

2.1.2.17 Summary of Events

In summary, the operating history includes a variety of initiating failures that resulted in the potential for overcooling by two mechanisms, SG overfeed and TBS failures. No steam line breaks have been experienced. In the 23 years of accumulated operating experience, a total of 186 reactor trips have occurred as of August, 1981. Following each trip not initiated by a loss of feedwater, the ICS initiated a main feedwater runback, nine of which were not successful, due to a slow runback or a failure to maintain the runback, which subsequently resulted in an overfeed of one or both SG's at a reduced flow rate. All nine overfeed events were successfully terminated by the high SG level trip of both MFW pumps, and in all cases the resulting RCS cooldown was insignificant. The one EFW overfeed occurred due to the original SG level setpoint for natural circulation which, as a result of the event, has since been reduced. Two events had potential for overcooling due to a loss of inventory through the pressurizer relief valve. Of the six TBS failure events, there were no instances where the TB valves on both SG's failed full open. If all four valves were open, it was a result of the operator manually throttling the valves to a partially open position. Three of the six TBS failures, each of which was a complete failure of both valves on one SG, did not even result in a reactor trip due to automatic ICS response and operator action. Failure of a main steam code safety relief valve to reseat contributed only

minimally to one event when the reseat occurred 150 psig below the normal reseat pressure. In almost all events operator response was very prompt and appropriate. In the remaining events operator response was sufficiently prompt to prevent an excessive cooldown. Operator error was infrequent and not severe.

Of the sixteen events only two exceed the 100 F/hr cooldown limit. Both events are precluded in the future by implemented design changes. Event 2 (140 F/hr) resulted in a reduction of the SG level setpoint for natural circulation. The likelihood of Event 13 (115 F/hr) recurring is very low due to the upgrade in ICS power supplies, increased operator awareness as a result of operating experience and review of similar events, and the development of an emergency procedure specific to the event.

2.1.3 Oconee Termination Criteria

2.1.3.1 Reactor Coolant Pumps (RCPs)

The RCPs are tripped when the primary system pressure falls to 1500 psig. When the RCS is greater than 50 F subcooled, one RCP per loop is to be restarted.

2.1.3.2 Feedwater

If all four RCPs trip, the ICS transfers main feedwater from the main feedwater header to the auxiliary feedwater header to promote natural circulation. The main feedwater pumps also trip on low suction pressure at 235 psig.

Auxiliary feedwater is isolated to both steam generators for steam supply system ruptures and to the faulty steam generator for steam generator tube ruptures. For a steam supply system rupture, the startup feedwater or emergency feedwater valve on the unaffected steam generator is to be controlled to bring level to 25 inches with the RCPs on or to 50% of the operating range with the RCPs off.

The emergency feedwater system (EFWS) inputs through the auxiliary feedwater header. The EFW pumps are automatically actuated by a main feedwater pump trip. Main feedwater pumps trip when discharge pressure is less than or equal to 750 psig and/or when main feedwater pump turbine oil pressure is low.

2.1.3.3 HPI Termination During LOCA

The HPI System must remain in operation until one of the two following conditions are met:

(1) The LPI System is in operation and flowing at a rate in excess of 1000 gpm in each line and the situation has been stable for 20 minutes, or

(2) All hot and cold leg temperatures are at least 50 F below the saturation temperature for the existing RCS pressure and HPI termination is necessary to prevent the indicated pressurizer level from going off scale-high.

2.1.3.4 HPI Termination During Steam Supply System Rupture

The HPI termination criteria for this event are the same as for HPI termination during a LOCA (see above).

2.1.3.5 Thermal-Hydraulic Analysis

(1) BAW-1648 Vessel Integrity Analysis. The analysis provided in B&W-1648(1) is limited to that of the small break LOCA with extended loss of feedwater. This was in response to an earlier NRC request(2). In the report, justifications were given to the selections of the break locations and sizes. Comparative analyses were made on three different break sizes, i.e., 0.007, 0.015, ad 0.023 ft^2, located in the pressurizer. Conservative

assumptions on RC pump trip, HPI flow and ECC water temperature were used. Comparisons were made between the cases with and without operator actions (i.e., HPI throttling). However, the decay heat of 1.2 times the ANS standard is not conservative in the sense that it prolongs the natural circulation.

(2) Oconee PTS Analysis. In the Oconee 150 day response(3) to NRC on the PTS issue, transients on small break LOCA with extended loss of feedwater, excessive feedwater and uncontrolled turbine bypass valve (TBV) leaks were analyzed for the pressure and temperature histories. The report gave several possible scenarios for each of the two overcooling transients (excessive FW and TBV leaks) with different combinations of component malfunctions that are most likely to occur. It also provided discussions on the selections of break locations, break sizes and system initial conditions. Analytical experience obtained from the B&W generic report (BAW-1648) was used to establish the bounding SB LOCA parameters. A realistic decay heat of 1.0 (not the previous value of 1.2) times the ANS standard was used. However, for the overcooling transients, there is a lack of detailed sensitivity analysis on these parameters. The selections of the scenarios was not based on

systematic PRA analyses. Operator actions are very critical to the pressure and temperature behavior during a PTS transient. Sensitivity analysis in this area also seems lacking.

2.2 Criteria for Procedural Reviews

The procedures to be reviewed were selected based on the perceived likelihood of conditions occurring that might subject the reactor vessel to pressurized thermal shock conditions and based on the potential consequences of less likely transients. Such procedures selected included normal startup and shutdown, steam generator tube rupture, steam supply system rupture, and loss of coolant accidents.

The audit criteria for the content of procedures was somewhat flexible to account for operator knowledge and to identify which procedures must be used to respond to a given transient. In addition, detailed operator knowledge of actions for preventing or mitigating PTS could offset some weaknesses in procedures. With this in mind, the following criteria were established for the procedures audit:

(1) Procedures should not instruct operators to take actions that would violate NDT limits.

(2) Procedures should provide guidance on recovering from transient or accident conditions without violating NDT or saturation limits.

(3) Procedures should provide guidance on recovering from PTS conditions.

(4) PTS procedural guidance should have a supporting technical basis.

(5) High pressure injection and charging system operating instructions should reflect a consideration for PTS.

(6) Feedwater and/or auxiliary feedwater operating instructions should reflect PTS concerns.

(7) An NDT curve and saturation curve should be provided in the control room. (Appendix G limits for cooldowns not exceeding 100 F/hr).

2.3 In-Plant Training Program

The effort of the audit team to determine the effectiveness of Duke Power Company (DPC) training in PTS began by selecting training criteria which would be used in evaluating the training material, interview Oconee shift personnel, and assessing the evaluation DPC made after completion of the training. The criteria developed into three general areas:

(1) Training should include specific instruction on NDT vessel limits for NORMAL modes of operation.

(2) Training should include specific instruction on NDT vessel limits for transients and accidents.

(3) Training should particularly emphasize those events known to require operator response to mitigate PTS.

More specific criteria were also developed to aid in the review of the training program and in preparation of interviews with operating personnel. These included:

(1) Training in NDT limits should include the knowledge that irradiation adversely affects fracture toughness

properties of the reactor vessel. Operators should know that the vessel and welds will lose ductile material properties and trend toward embrittlement.

(2) Operators should be aware that NRC has sent letters to DPC on the PTS issue and that DPC had responded that additional training was underway.

(3) Operators should understand that a rapid reduction in reactor vessel temperature/pressure can raise the possibility of crack propagation, particularly if pressure rises after the temperature reaches its lowest value.

(4) Operators should be aware of the types of events which are known to involve PTS (such as MSL breaks and secondary side malfunctions).

(5) Operators should appreciate that other safety limits (such as core cooling and shutdown margin) must also be balanced with the PTS limits.

(6) Training should emphasize the instrumentation available to observe key parameters as they approach limits. Strategies/options which are under operator control

should be emphasized.

(7) Operators should understand the basis for current emphasis on PTS, specifically more severe transients have occurred than expected (Rancho Seco, Crystal River).

DPC was requested to furnish an outline of their training program on PTS and the lesson plan which was used in the training classes. They were also questioned on the method used to evaluate the effectiveness of the training sessions.

Preparation for review of the training program included a review of DPC correspondence with the Commission, including a report on vessel integrity of Babcok & Wilcox operating plants (BAW-1648), normal and emergency procedures furnished by DPC, technical specifications, and the FSAR. An interview plan was developed which used the general training criteria and the specific subjects that were included in the DPC training material.

Each interview was preceded by a discussion of the reason for the audit and acknowledgment that the individual could use all material available in the control room, particularly the followup or recovery steps in the emergency procedures. Several interview aids were

prepared to provide the operators a point of reference for discussion and to allow them to predict responses or execute recovery strategies to mitigate PTS or challenges to other limits.

3. KEY FINDINGS OF THE OCONEE AUDIT

The following is a description of how the audit was conducted and the key findings resulting from the audit.

3.1 Description of Audit

Prior to the plant visit to Oconee, PNL reviewed the procedures listed in 3.3.1, the Oconee training outline which included a description of past events and the Oconee 150 day response (DPC-RS-1001 dated Jan 1982). During the plant visit, PNL reviewed the training schedule, interviewed key members of the training staff and an individual responsible for procedures writing. Procedures which dealt with PTS were reviewed against the audit criteria. Past Oconee PTS events, potential events and potential overcooling transient scenarios used in the DPC simulations (as reported in DPC-RS-1001) were analyzed along with the procedures and these served as a basis for interviews with plant operating personnel to determine the effectiveness of the training program and operator knowledge on PTS. Seven licensed operations people were interviewed.

3.2 Training

3.2.1 Introduction

The audit of Oconee's training program consisted of a review of the PTS training outline, a description of the requalification program and a detailed training schedule and syllabus. We also interviewed three key members of the training staff and the following licensed operations personnel:

- 2 STAs (are also licensed SROs)
- An assistant shift supervisor
- A shift supervisor
- 2 control operators
- An assistant control operator

3.2.2 Comparison of Training with Audit Criteria

(1) Training should include specific instruction on NDT vessel limits for NORMAL mode of operation. Segment 1 of the Periodic Training Requalification includes a discussion of the PTS issue in general and NDT vessel limits and the interim brittle fracture curve as they apply to both normal and off-normal operations. All interviewees showed good knowledge in this area.

(2) Training should include specific instructions on NDT vessel limits for major transients and accidents. Segment of the requalification training deals with NDT vessel limits and the interim brittle fracture curve and their use during transient. This is also a topic covered in shift training when there are changes to procedures which have PTS implications. All interviewees were questioned in this area and demonstrated a good understanding.

(3) Training should particularly emphasize those events known to require operator response to mitigate PTS. Training in the classroom, on shift and on the generic simulator at B&W does cover these topics. The emphasis is on preventing PTS and includes termination criteria

for HPI, use of P-T diagrams and how to establish and maintain subcooling margins and not exceed cooldown rates. One area that should be given more attention in training and in the procedures is what the operator should do if he finds the plant operating either on the saturation curve or beyond the interim brittle fracture curve.

3.2.3 Findings on Training

The training program appears to have covered PTS subject adequately. The training program involves continuous requalification training which is designed to ensure that operators are constantly aware of PTS rather than being retrained only once a year. The area that was found to be weak deals with acquainting the operators with past PTS events that have occurred in the industry, e.g., Rancho Seco and Crystal River. This weakness was evident from our interviews and these events were not listed in the training syllabus.

Both the review of the training program and interviews with the supervisors, STAs and control operators indicated that they had a good understanding of PTS. They demonstrated a knowledge of transients that could result in PTS and a generally good understanding of how to avoid PTS. They seemed a little less certain of what to do if they found themselves operating either on the saturation curve or

approaching NDT limits. Concurrently with the PTS audit team visit, PNL conducted licensing examinations of eight control operators. Several questions on PTS were asked and in all cases the examinees showed a good understanding of PTS.

3.3 Procedures

3.3.1 Introduction

Our audit included a review of selected procedures as discussed in Section 2.2, discussions with a licensee representative on the instructions relating to PTS and the basis for these instructions, and an audit of the control room copy of the procedures to determine its legibility and currency. Our audit included the following Operating Procedures (OP) and Emergency Procedures (EP):

OP-01 Controlling Procedure for Unit Startup

OP-10 Controlling Procedure for Unit Shutdown

EP-04 Loss of Reactor Coolant

EP-08 Steam Supply System Rupture

EP-17 Steam Generator Tube Rupture

3.3.2 Comparison of Procedures With the Audit Criteria

(1) Procedures should not instruct operators to take actions that would violate NDT limits. The procedures that were

audited generally did not appear to contain instructions that would cause an operator to violate NDT limits. The procedures referred to or included cautions to stay within the limits of the Interim Brittle Fracture Limit (IBFL) curves, which are more conservative than the NDT limits. The NDT curve was consistent with the technical specification for heatup and cooldown limits. The IBFL curve was based on Babcock & Wilcox analyses and was, essentially, a 100 F subcooling curve below the pressure at which HPI is initiated (HPI 1500). Above 1500 psig the curve rises vertically on the 500 F to the upper limit of the P-T diagram (2400 psig).

In many cases the procedures direct the operator to use the P-T diagram enclosed with the procedures. This P-T diagram is to be used to determine whether the plant is operating in the acceptable regions with respect to subcooling margin and cooldown rate. There are five instructions on the P-T diagram. Instruction 4 states, "maintaining the Reactor Coolant at 50 F subcooled takes precedence over the Brittle Fracture Limit." This instruction was found to be ambiguous and confusing to the operators we interviewed and should be clarified. In discussions with plant representatives, this was brought up and they have agreed to clarify the meaning

of this instruction.

(2) Procedures should provide guidance on recovering from transient or accident conditions without violating NDT or saturation limits. See item (1) above for a discussion on NDT limits. The procedure for depressurization refers operators to the figure (a P-T diagram) that shows the saturation curve, the 50 F subcooled cure, the IBFL curve, and the NDT curve. The figure provides instructions that tell the operator: 1) to operate only between the IBFL curve and the 50 F subcooled curve with RCPs off, and 2) to operate between the NDT curve and the 50 F subcooled curve with the RCPs on. In all cases where a PTS event is possible, the procedures refer the operator to this diagram.

(3) Procedures should provide guidance on recovering from PTS conditions. While the procedures provide instructions for maintaining the RCS within conditions allowed by the NDT curve, the procedures do not cover cases where a PTS event has occurred before the operators are able to begin to control plant conditions. The procedures also do not give guidance to the operator given that the cooldown rate has been exceeded. Thus,

there are no instructions in the procedures to tell the operator how to recover from a PTS condition.

(4) PTS procedural guidance should have a supporting technical basis. The procedural guidance on PTS is based on analyses and studies conducted by B&W and reported in the 150 day response (BAW-1648).

(5) High pressure injection and charging system operating instructions should reflect a consideration for PTS. The 50 F subcooling criterion for HPI termination reflects PTS concerns. There are no specific instructions for operation of the charging pumps following a depressurization.

(6) Feedwater (FW) and/or auxiliary feedwater (AFW) operating instructions should reflect PTS concerns. Instructions are provided in the steam generator tube rupture and the loss-of-coolant procedures to terminate FW/AFW flow to the faulted steam generator. These procedures also provide instructions to maintain steam generator levels in the nonfaulted steam generator within a defined baud.

(7) An NDT curve and a saturation curve should be provided

in the control room. These curves are provided in all applicable procedures.

3.3.3 Findings on Procedures

In general, the procedures do give the operator guidance on preventing a PTS event. The guidance deals with such items as terminating HPI and conditions for restarting reactor coolant pumps. The procedures should have included in them the actions the operator should take if he finds the plant approaching or in a PTS event. Instruction 4 on the P-T diagram is ambiguous and confusing and should be clarified. There are no specific instructions on operation of the changing pumps following a depressurization.

3.4 Summary

Seven licensed individuals were interviewed. They ranged in experience from a shift supervisor to an assistant control operator. They all exhibited an understanding of the basic PTS issue and why PTS was a concern to their plant. We presented a number of detailed scenarios which involved the potential for over-cooling or over-cooling with repressurization and all interviewees knew what to do. The people we interviewed in the control room were able to describe the right actions and demonstrate that they knew the location and functions of the displays and controls involved in their actions.

The training program covers PTS subjects in the classroom, during shift training and in the simulator. The procedures are generally adequate in their coverage of PTS. The only subject that needs attention both in the procedures and training is that of how to recover from a situation where the plant is operating outside the acceptable zones on the P-T diagrams. The training program did not adequately cover past PTS events in the industry. The procedures called for the operators to plot cooldown rate but did not provide a means to do this.

4 RECOMMENDATIONS

Based on the findings presented in Section 3 the Oconee audit team recommends the following:

(1) The training program should provide a thorough understanding of past industry-wide PTS events and how the operator would deal with these were they to occur at Oconee.

(2) The training program and the procedures should provide more guidance to operators on how to recover from situations where the plant is found to be outside the 50 F subcooling curve and NDT limit curve (Region I &

II) on the P-T diagram.

(3) The operators should be provided a better means of tracking cooldown rate and subcooling margin. The instantaneous subcooling margin is displayed by a digital display and the instantaneous cooldown rate is shown on a CRT. In both cases the operators must plot this information on a graph in order to see trends. When the computer is down this task becomes much more difficult, very time consuming, and is prove to human error.

In the longer term, the procedures written as part of the B&W Anticipated Transient Operating Guidelines (ATOG) program should be reviewed under item IC1 of the Task Action Plan to verify that they provide the operator with the guidance to avoid a PTS event and how to cope with a PTS situation should that become necessary.

REFERENCES

(1) BAW-1648 "Thermal-Mechanical Report - Effect of HPI on Vessel Integrity for Small Break LOCA Event with Extended Loss of Feedwater", Babcock & Wilcox, Lynchburg, Virginia, 1980

(2) NUREG-0737, "Clarification to the Action Plan", 1980

(3) Licensee 150 - Day Response to NRC on PTS, Duke Power Company, Oconee Nuclear Station Unit 1, DPC-RS-1001, January 1982