U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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| Docket Nos: | 50-413, 50-414 |
| License Nos: | NPF-35, NPF-52 |
| Report Nos: | 50-413/98-12, 50-414/98-12 |
| Licensee: | Duke Energy Corporation |
| Facility: | Catawba Nuclear Station, Units 1 and 2 |
| Location: | 422 South Church Street<br>Charlotte, NC 28242 |
| Dates: | December 13, 1998 - January 23, 1999 |
| Inspectors: | D. Roberts, Senior Resident Inspector<br>R. Franovich, Resident Inspector<br>M. Giles, Resident Inspector<br>F. Jape, Senior Project Manager (O8.5, 08.6, O8.7, M8.2) |
| Approved by: | C. Ogle, Chief<br>Reactor Projects Branch 1<br>Division of Reactor Projects |

Enclosure 2

EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/98-12, 50-414/98-12

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an announced inspection by one regional inspector. [Applicable template codes and the assessment for items inspected are provided below.]

Operations

- The licensee responded to numerous operational challenges during the period in a safe and effective manner. Operators maintained the plant in a stable condition, especially during their actions to preclude an automatic reactor trip following a Unit 2 cooling tower gate failure. Events requiring NRC notification were properly reported in accordance with 10 CFR 50.72. (Section O1.2; [1A - POS])

- An apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified involving the failure to effectively translate the design basis of the auxiliary feedwater system into specifications, drawings, and procedures by providing a system that could withstand the failure of valve 1(2) CA-6 following auxiliary feedwater condensate storage tank depletion during a postulated dual-unit loss of offsite power scenario. (Section O8.2; [4A - EEI])

- A violation was identified for failing to conduct an adequate 10 CFR 50.59 safety evaluation for changes to abnormal operating procedures AP-6 and AP-17 that could have impacted standby shutdown system operability. (Section O8.3; [1C, 4B - VIO])

- A non-cited violation was identified for failing to secure a control room ventilation system damper in accordance with a clearance procedure, resulting in a dual-unit entry into Technical Specification 3.0.3. The licensee identified training and human factors issues which contributed to the July 1998 incident. (Section O8.5; [1A, 3B - NEG; 5A, 5C - NCV])

Maintenance

- The maintenance and surveillance activities observed were performed well, with proper adherence to procedural compliance, equipment calibration, and radiation protection requirements. (Section M1.1; [2B, 3A - POS])

Engineering

- A non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified for the failure to effectively translate the design basis and applicable regulatory requirements for containment penetrations involving main steam supply piping to the turbine-driven auxiliary feedwater pumps into specifications to ensure compliance with 10 CFR 50, Appendix A, General Design Criterion 57. (Section E8.2; [4A - NEG; 5A, 5C - NCV])

<u>Plant Support</u>

- The licensee's Emergency Preparedness regulatory audit was effective in identifying issues and/or areas for improvement. The licensee took appropriate action to address issues that were identified. (Section P7.1; [5A, 5C - POS])

## Report Details

### Summary of Plant Status

Unit 1 operated at or near 100 percent power during the inspection period.

Unit 2 operated at or near 100 percent power until January 15, 1999, when a relay failure and subsequent blown fuse caused the licensee to declare two auxiliary feedwater pumps inoperable and initiate a reactor shutdown in accordance with the applicable Technical Specification (TS) action statement. The relay and fuse were replaced, with the reactor power reduction halted at 24 percent, and the unit was returned to full power on January 16, 1999. Reactor power remained at 100 percent until January 20, 1999, when the 2C cooling tower drop gate support structure failed, allowing the gate to drop into the cooling tower outlet stream and block flow to the main condenser. A rapid power decrease to 50 percent was initiated to prevent a loss of condenser vacuum and subsequent turbine/reactor trip. Unit power was increased to approximately 70 percent while condenser vacuum was maintained, and the gate was removed from the cooling tower outlet path that evening. Reactor power was returned to 100 percent on the same day and remained at or near full power for the remainder of the inspection period.

## I. Operations

### O1 Conduct of Operations

#### O1.1 General Comments (71707)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness and communications, and adherence to approved procedures. The inspectors attended operations shift turnovers and site direction meetings to maintain awareness of overall plant status and operations. Operator logs were reviewed to verify operational safety and compliance with TS. Instrumentation, computer indications, and safety system lineups were periodically reviewed, along with equipment removal and restoration tagouts to assess system availability. The TS Action Item Log (TSAIL) books for both units were reviewed daily for potential entries into limiting conditions for operation (LCO) action statements. The inspectors conducted plant tours to observe material condition and housekeeping. Problem Identification Process (PIP) reports were routinely reviewed to ensure that potential safety concerns and equipment problems were resolved. No problems, violations or deviations were identified in the above areas.

#### O1.2 Prompt Onsite Response to Operational Events

a. Inspection Scope (93702)

The inspectors responded to several events during the period. The inspectors reviewed the circumstances associated with each event, verified that plant personnel responded to the events in accordance with governing plant programs and procedures, verified that the plant was in a safe condition, and confirmed that the licensee made the appropriate notifications to the NRC as required by 10 CFR 50.72.

b. Observations and Findings

Two minor events involving the loss of the Emergency Notification System on December 23, 1998, and January 3, 1999, both of which were quickly corrected, were reported as required by 10 CFR 50.72. The inspectors reviewed additional items, which are discussed below.

Standby Shutdown Facility (SSF) Potentially Outside Design Basis

On December 29, 1998, the licensee identified two mispositioned breakers (FO2C and RO3D) on motor control center SMXG. The breakers supply alternate power to bus EMXS, which is relied upon for accident mitigation from the SSF. The breakers, which were found in the open position, caused the SSF to be inoperable. The licensee determined that the system had been restored with the breakers in the open position following SSF maintenance work two weeks earlier. Further investigation revealed that the restoration procedure incorrectly directed that the SSF be returned to service with the breakers open. The licensee initiated a root cause evaluation to determine why the restoration procedure contained this error and were in the process of preparing Licensee Event Report 50-413/98-19. The inspectors will independently review this issue during closeout of the LER to assess the licensee's corrective actions and determine the safety and regulatory significance.

Initiation of TS-Required Unit 2 Shutdown due to Two Auxiliary Feedwater (CA) Pumps Being Declared Inoperable

On January 15, 1999, the licensee reported a Unit 2 shutdown that was initiated in accordance with former Catawba TS Action 3.7.1.2.b involving two inoperable CA pumps. Equipment problems that resulted in the two CA pumps being inoperable and the associated actions to correct the problems are documented in Section O2.2 of this inspection report (IR).

Initiation of Rapid Power Reduction Due to Failed Unit 2 Cooling Tower Gate

On January 20, 1999, at 3:55 a.m., control room operators received an annunciator alarm for low level in the 2B cooling tower basin. A second annunciator alarm was received shortly thereafter for low condenser circulating water (RC) pump suction pressure. Control room operators dispatched a non-licensed operator (NLO) to investigate the cause of the annunciators. The NLO reported that the 2C cooling tower basin was overflowing. Control room operators initiated a rapid power decrease to 50 percent to avoid a loss of condenser vacuum turbine trip, and removed the 2C cooling tower and 2D RC pump from service. Reactor power was reduced to 50 percent at 4:25 a.m. Later that morning, the licensee determined that a drop gate support structure had corroded and failed, causing the drop gate to fall into the cooling tower outlet stream to the condenser. After the cause was determined, operators performed a reactor power increase at 11:30 a.m. to the extent that condenser vacuum could be maintained. The licensee determined that the gate did not perform a safety function and decided to completely remove it from the basin area. The drop gate was removed and reactor power was returned to 100 percent later that day. The licensee identified similar corrosion of the Unit 1 C cooling tower drop gate support structure and removed it as a conservative measure. The Unit 1 and Unit 2 A and B cooling towers also have drop gates, but their support structures are of a different design that, according to the licensee, is not vulnerable to the same type of failure. The licensee plans to evaluate the condition of these drop gates during upcoming refueling outages. The inspectors identified no safety concerns relative to the long-term removal of the C drop gates.

c. Conclusions

The licensee responded to numerous operational challenges during the period in a safe and effective manner. Operators maintained the plant in a stable condition, especially during their actions to preclude an automatic reactor trip following a Unit 2 cooling tower gate failure. Events requiring NRC notification were properly reported in accordance with 10 CFR 50.72.

## O2 Operational Status of Facilities and Equipment

O2.1 Component Cooling Water (CCW) System Walkdown - General Comments (71707)

The inspectors performed an engineered safety feature (ESF) walkdown of the CCW system. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR); design basis documentation (DBD); applicable TS; risk assessment documentation; piping and instrumentation drawings (P&IDs); Procedure OP/1/A/6400/005, Component Cooling System, Revision 85; and Procedure PT/1/A/4400/003C, Component Cooling System Valve Verification, Revision 25.

The inspectors determined that the material condition of essential CCW piping, valves, pumps, surge tanks and radiation monitors was good; information provided in the P&IDs, operating and surveillance procedures, UFSAR and DBD was consistent; valves in the essential header were in their correct positions and secured (if required); and pumps and instrumentation functioned as expected during inservice testing of the Unit 2 A train of the system. Minor editorial errors were identified in the operating and periodic test procedures and forwarded to the procedure writers group for correction. No violations or deviations were identified.

O2.2 Electrical Failure Causes Two CA Pumps to be Declared Inoperable

a. Inspection Scope (71707)

On January 15, 1999, the licensee initiated a Unit 2 shutdown following an electrical relay failure in the turbine-driven pump's auxiliary control panel that caused the turbine-driven and A train motor-driven CA pumps to be declared inoperable. The inspectors observed the unit power reduction, observed troubleshooting activities, attended station meetings, reviewed the applicable TS, and reviewed electrical drawings to understand the extent of the relay failure's impact on the CA system and assess the licensee's corrective actions.

b. Observations and Findings

At 6:30 a.m. on January 15, 1999, a blown fuse in the CA turbine-driven pump local control panel caused (1) the A train reset light and indications for various A train valves associated with the turbine-driven CA pump to transfer to the local panel from the control room, and (2) the auxiliary tempering flow isolation valves associated with all four steam generators to close. The licensee declared the turbine-driven CA pump inoperable at 6:30 a.m. This placed the unit in a 72-hour LCO. At 8:20 a.m., the licensee determined that the blown fuse affected the A train logic circuit controlling automatic CA supply swapover to nuclear service water (RN) upon low suction pressure for both the turbine-driven pump and the A train motor-driven pump. Other A train motor-driven pump auto-start functions were lost as well, including auto-starts on low-low steam generator level and on loss of both main feedwater pumps. Train B logic was unaffected by the failure; hence, the B motor-driven pump remained operable, as did all B train functions associated with operation of the turbine-driven pump. The A train motor-driven CA pump was declared inoperable at 8:20 a.m. and the licensee entered a six-hour shutdown LCO action for having two pumps inoperable. A rapid power decrease was initiated at 9:44 a.m.

During subsequent troubleshooting, the licensee determined that a normally energized Cuttler-Hammer relay had failed, causing a fuse (Fuse F39 on the positive leg of the circuit) to open. The failed relay was isolated from the portion of the control circuitry affecting the turbine-driven CA pump, the fuse was replaced, and the turbine-driven CA pump was returned to operable status at 1:06 p.m. By this time, the licensee had terminated the reactor power decrease at 24 percent reactor power. The licensee's actions were consistent with NRC guidance provided in Enforcement Guidance Memorandum 97-013, Compliance with Technical Specification Limiting Conditions for Operation and Action Statements. This Enforcement Guidance Memorandum provides guidance on compliance with TS LCO action statements. The licensee was performing a past-operability evaluation to determine whether both pumps were simultaneously inoperable for more than the six hours allowed by TS. The plant remained in a 72-hour LCO action statement with the A motor-driven pump inoperable due to the isolated failed relay.

The licensee found a burned-out coil in the relay and initially determined it to be a random failure. They determined that replacement of the coil alone, while leaving the relay contact block intact, would preclude the need to perform lengthy post-maintenance testing of motor-driven pump functions associated with the relay contacts. At approximately 5:30 p.m., the licensee de-energized the circuit to allow workers safe access to the relay, and re-entered the six-hour LCO action for coil replacement. The licensee performed resistance checks across relay contacts and a visual verification of control power indications associated with components and functions affected by the relay as post-maintenance testing. In a management meeting, the inspectors questioned the licensee's approach to repairing and testing the relay; licensee personnel stated that the type of relay involved was highly reliable and that no evidence had been found to contradict a random failure. The inspectors detected an acrid smell from the burned-out coil while observing troubleshooting activities, but no obvious causes were noticed. Both pumps were declared operable by 7:46 p.m following relay coil replacement and verification of proper control board and auxiliary shutdown panel indications. The unit was returned to 100 percent power on January 16, 1999.

Subsequent to the inspection period, another failure of the same relay occurred on January 29, 1999. The second failure caused five-amp Fuse F40 on the neutral leg of the same circuit to open. The licensee again declared the two CA pumps inoperable and entered the six-hour shutdown action statement. This time, the licensee replaced the entire relay (including contact block) and performed extensive functional testing of the A motor-driven pump, including verifications that auto-start functions cycled the pump motor circuit breaker (while racked to the test position), and taking coil current readings prior to, during and after operation of both the A motor-driven pump and the turbine-driven pump. The licensee also initiated a Failure Investigation Process team to determine the actual root cause of both relay coil failures. Licensee personnel were monitoring the relay's performance by taking current readings once per shift until a cause for the relay's failures is determined.

The licensee is currently evaluating the actual impact of the failed relay and blown fuses on the turbine-driven CA pump to determine if their decision to declare the pump inoperable - although redundant B train functions associated with it were unaffected - was valid. Pending additional NRC review of the licensee's root cause determination for the failures, initial corrective actions following the first failure, the turbine-driven pump operability evaluation, and any corrective actions identified to prevent recurrence, this item is characterized as Inspector Follow-up Item (IFI) 50-414/98-12-01: Relay Failures Cause Two CA Pumps to be Declared Inoperable.

c. Conclusions

An IFI was identified to follow the licensee's actions to determine (1) the cause of a relay failure and blown fuse in the turbine-driven auxiliary feedwater pump remote shutdown panel, (2) the past-operability for the turbine-driven pump, and (3) any additional corrective actions. A second relay failure indicated that the licensee's actions to identify and/or correct the cause of the first failure may have been inadequate.

**O8 Miscellaneous Operations Issues** (92901)

O8.1 (Closed) Licensee Event Report (LER) 50-413/97-011: Engineering Safety Feature (ESF) Actuation due to Reactor Coolant System Leakage from Loop Drain Valves

This LER described a Unit 1 event in which an ESF actuation (manual start of a second high head safety injection pump) occurred during startup from refueling outage 1EOC10. On December 30, 1997, with Unit 1 in Mode 3, at 554 degrees Fahrenheit and 2200 pounds per square inch (psig), control room operators identified a reactor coolant system leak of approximately 40 gallons per minute. Operators entered AP/1/A/5500/10, Reactor Coolant Leak, and manually started a second centrifugal charging pump to keep up with the leak. A Notification of Unusual Event (NOUE) was declared and the Operations Support Center and the Technical Support Center were activated. The reactor coolant system was cooled down to 466 degrees Fahrenheit and 1300 psig.

Valves 1NC-13 and 1NC-106 (both in-series low-point drain isolation valves on reactor coolant loop 1C), were found to be approximately one quarter turn open. This was the source of the leak. Both valves were closed and the excessive leakage was terminated. The NOUE was subsequently exited.

An in-depth root cause analysis was performed by the licensee who could not determine how the two low-point drain isolation valves were moved from the fully closed position. The licensee concluded that this event was not likely caused by a human performance problem. It was identified that the valves were manipulated earlier during the outage to facilitate draining portions of the reactor coolant system. Documentation indicated that the valves had been closed on December 24, 1997.

The inspectors reviewed evaluations contained in PIP report numbers 1-C98-0002 and 1-C98-0003, which determined that no significant damage occurred to any safety-related equipment during this event. The inspectors did not identify any technical inadequacies in the completed evaluations.

The inspectors also reviewed other corrective actions which consisted of evaluating the development of a critical valve checklist for valves that lead to loop drains and valves that connect systems during plant heatup and pressurization, and the licensees' evaluation of using some method to physically protect critical valves from the potential of inadvertent mispositioning. The licensee considered the latter corrective action to be undesirable in that it could hinder the ability to operate the affected valves in a timely manner if it became necessary. The critical valve checklist was added to Procedures OP/1/A/6100/001, Controlling Procedure For Unit Startup, Revision 191; and OP/2/A6100/001, Controlling Procedure For Unit Startup, Revision 115. The inspectors concluded that the completed corrective actions were adequate. This LER is closed.

O8.2 (Closed) LER 50-413/97-03: Auxiliary Feedwater System Found Outside of Design Basis

(Closed) Unresolved Item (URI) 50-413,414/97-08-07: Potential Air Binding of Auxiliary Feedwater Pumps

LER 50-413/97-03 discussed a design deficiency associated with the CA system for both units that had existed since plant construction and rendered the system outside of its design basis. Issues related to this licensee-identified finding have been discussed in Inspection Reports 50-413,414/97-08 and 98-01.

The Catawba CA system relied on a nonsafety-related condensate storage system (CSS) that included three tanks: a preferred, normally-aligned CA condensate storage tank (CACST) that was common to both units; unit-specific upper surge tanks (UST); and the main condenser hotwells (also unit-specific). The CA pumps were designed to take a suction from the CSS (first the CACST, then UST, and finally the hotwell), but were intended to have their suctions transferred to the safety-related, seismically qualified RN system if the CSS was lost. Hence, the licensee ultimately took credit for the RN system in maintaining the CA system capable of performing its design basis functions.

The reported design deficiency involved piping configurations associated with CA pump suction from the CACST and UST that could potentially cause the failure of all three pumps (two motor-driven, one steam turbine-driven) for either unit during a design basis event. Specifically, following a postulated dual-unit loss of offsite power (LOOP) event with a steamline or feedline break on one unit, a depleted CACST, and a single failure preventing the automatic closure of the affected unit's CACST isolation valve (CA-6), air could be introduced into the suction of the affected unit's pumps prior to taking suction from the UST. The air entrainment would be aggravated by high CA flow rates due to the steamline or feedline break. The entrapped air would be sufficient to cause all three pumps to fail, prior to being swapped from the nonseismic, nonsafety-grade condensate sources to the RN system.

Upon discovery, the licensee declared the system inoperable on May 15, 1997. As a compensatory measure, plant operators isolated the CACST from both units' CA systems by closing valves 1(2) CA-6, thus allowing the pumps to take suction directly from the USTs. Isolating the CACST from the CA pumps removed about 42,500 gallons of condensate quality water from the CSS and had the undesirable effect of potentially introducing non-condensate quality RN system water into the steam generators earlier during an event, but it successfully eliminated the failure mode associated with the adverse CACST/CA interaction. After isolating the CACST, the licensee declared the system operable, but degraded, and exited the TS LCO action statement. The remaining capacity of 85,000 gallons/unit from the UST and 170,000 gallons/unit from the main condenser hotwell was sufficient to satisfy Unit 2 TS requirements for the CSS to have a minimum contained water volume of at least 225,000 gallons. While approximately the same sufficient quantity of water was available for Unit 1, that unit did not have specific CSS water volume requirements delineated in its TS. During routine plant and control room tours, the inspectors have verified that valves 1(2) CA-6 were secured closed to maintain the system operable for both units.

Since the licensee's finding, a vendor performed a second analysis that confirmed the licensee's conclusions related to air entrainment. In addition, the licensee revised procedures requiring that control room operators implement abnormal procedure AP/1(2)/5500/06, Loss of Steam Generator Feedwater, upon any automatic actuation of the CA pumps. This procedure includes guidance for responding to a loss of the normal supply to the CA pumps. The inspectors verified that the procedures had an entry point associated with any CA automatic actuation. The licensee has conceptualized a modification to the current piping configuration that will return the pump suction alignment to the CACST and restore the system to a status where compensatory measures are not required. The proposed modification will also address other recent licensee-identified concerns associated with adverse system interactions between the CA system and the normally-operating secondary plant systems with which it communicates. At the close of the inspection period, the proposed concept had been approved by the Nuclear Safety Review Board, but a modification package had not yet been developed or scheduled for implementation.

The design basis for the CA system is described in the licensee's UFSAR, Section 10.4.9. It states "the CA system will provide the required flow to two or more [steam generators] regardless of any single active or passive failure in the long term." It further states "as the CA system serves a vital safety-related function during all postulated occurrences, two trains supplied by a safety grade, seismically designed water source must be assured at the pump suctions to assure pump operability and function...a reliable means of detecting loss of condensate source and automatic transfer of the pump suctions to the nuclear service water source is employed." It indicates that automatic controls will transfer the pump suctions to RN upon detection of any of the listed postulated failures of the non-seismic condensate supplies. The listed failures include "the partial or complete loss of source due to air leakage into the system from... failure to isolate a depleted source," and a "partial loss of source due to steam void formation in the suction piping caused by excessive friction loss associated with a high flow rate."

The inspectors determined that the failure to effectively translate the design basis of the CA system into specifications, drawings, and procedures by providing a system that could withstand the failure of 1(2) CA-6 following CACST depletion during the LOOP scenario constituted an apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Control. [Apparent Violation (EEI) 50-413, 414/98-12-02: Auxiliary Feedwater System Outside Design Basis due to Potential Adverse Interaction Between CACST and CA During Swapover.]

The licensee determined the root cause of the design error to be an erroneous assumption that the limiting failure mode associated with the CSS was a break in the nonseismic piping at a point downstream of where the three condensate sources tied together. As a result, no transient analysis was performed on the individual sources. The licensee has identified several failure modes and adverse system interactions associated with the CA system, two of which have been described in LER 50-413/96-12 and LER 50-413/98-02 in the past two years. The inspectors reviewed the corrective actions specified for LER 50-413/96-12, which included an investigation into the sequence of design changes for the CA system since initial construction, a reconstitution of the electrical and mechanical design basis for standby shutdown facility interfacing systems (which includes CA and RN), and a review of the Operating Experience Database for these systems to identify other adverse trends or corrective actions. The inspectors determined that these actions were specifically intended to address previous modifications to the CA system and any impact those changes might have had on design basis assumptions or statements contained in the UFSAR. The inspectors concluded that the corrective actions from LER 50-413/96-12 could not reasonably have resulted in the licensee identifying the CACST/CA interface problem earlier. The licensee believes that the proposed long-term modification to the system will correct the CACST/CA and other system interface problems.

O8.3 (Closed) URI 50-413,414/98-09-02: Potentially Inadequate Procedures Not Ensuring the Operability of the SSF

This URI was opened to determine the regulatory and safety impact of abnormal operating procedures that could render the Standby Shutdown System (SSS)/SSF inoperable, and to determine if the procedures had been performed in the past during operational modes requiring the SSF to be operable.

The inspectors identified that abnormal operating procedures AP/1(2)/A/5500/06 (AP-06), Loss of S/G Feedwater, Revision 20 (16); and AP/1(2)/A/5500/17 (AP-17), Loss of Control Room, Revision 36 (30) each contained steps allowing operators to defeat the automatic alignment of the turbine-driven auxiliary feedwater pump (TDAFWP) suction to the RC system by opening circuit breakers associated with valves 1(2)CA-174, 175, and 178. Valves CA-174 and 175 were designed to automatically open on low TDAFWP suction pressure and provide an assured pump suction source from the nonsafety-related RC system. With valves CA-174 and CA-175 normally in the closed position, the inspectors were concerned that the SSS would not be capable of performing its intended function if the normal auxiliary feedwater supply sources became unavailable and a transfer to the SSF from the control room was required with power removed from the valve actuators. Technical Specification Surveillance Requirement 4.7.13.5 requires manipulation of this equipment from the SSF to demonstrate system operability.

From a review of the 10 CFR 50.59 safety evaluation that had accompanied the 1990 procedure change incorporating the questionable steps into AP-06, the inspectors determined that the licensee had intended to avoid putting non-condensate quality water from the RC system into the steam generators by allowing the condenser hotwell to be a more reliable source of water for the auxiliary feedwater pumps. The condenser hotwell piping design is such that it provides a suction pressure to the CA pumps that is very close to the low suction pressure setpoints associated with auto-swapover to the RN and RC systems. The 1990 procedure change was intended to preclude an inadvertent swapover to RC while the pumps were aligned to the hotwell, after the other two condensate sources (CACST and UST) were lost or depleted, and RN swapover was potentially unavailable. There were no accompanying steps in the procedure requiring operators to declare the SSS inoperable and apply TS LCO actions with the RC auto-swap capability defeated.

Procedure AP-06 had been performed four times in recent years following reactor trip events with automatic auxiliary feedwater system actuations. The inspectors determined that the steps to open the subject CA valve circuit breakers had not been performed on any of those occasions. During each event, operators had exited the procedure as plant conditions were stabilized, which precluded the need to align pump suction to the hotwell or disable the RC auto-swapover capability.

Procedure AP-17 had not been performed since plant construction. However, the licensee presented a possible procedural scenario in which operators could transfer to the SSF with the swapover disabled, and acknowledged that such actions could occur without written guidance to ensure the breakers supplying CA-174 and CA-175 were energized. The licensee stated that this error would be potentially mitigated by the fact that the valve indications on the SSF control panel would not be illuminated, thereby alerting operators to check the breakers for these valves, which are located in a room on the second level of the SSF directly above the SSF control panel.

The licensee immediately corrected AP-06 and AP-17 by removing the steps to de-energize valves CA-174 and 175. The inspectors verified that the changes were incorporated into the latest procedure revisions. The inspectors concluded that the safety consequences of the procedural inadequacies were mitigated by the fact that the steps had never actually been performed under either procedure, and that the valve breakers were easily accessible in the SSF in the event operators needed to re-energize them. Furthermore, the probability of depleting all three condensate quality sources and the safety-related RN supply, and relying on the RC suction swapover capability was small. The likelihood of exceeding the seven-day outage time allowed for the SSS by TS 3.7.13 due to this error was also considered small.

Notwithstanding the minor actual consequences, the inspectors considered the evaluation conducted under 10 CFR 50.59 for the 1990 procedural changes that would have allowed the disabling of the automatic TDAFWP suction swapover capability to the RC system to be inadequate in that it did not consider potential impact on SSS operability. In determining whether an unreviewed safety question (USQ) existed, the licensee did not properly evaluate the procedure changes against questions regarding the probability of malfunction of equipment important to safety (i.e., the TDAFWP) or the reduction of margin of safety as defined in the SSS TS basis (i.e., the capability to control and monitor vital systems from locations external to the control room). The safety evaluation was more focused on ensuring the reliability of the main condenser hotwell as a pump suction source than on SSS operability. This resulted in procedural inadequacies that potentially involved a USQ and continued to exist throughout several procedural revisions for over eight years. The inspectors concluded that the failure to provide an adequate safety evaluation to address the potential USQ as it related to Procedures AP-6 and AP-17 constituted a violation of 10 CFR 50.59, and is characterized as Violation (VIO) 50-413,414/98-12-03: Failure to Conduct an Adequate 10 CFR 50.59 Safety Evaluation for Changes to Procedures AP-6 and AP-17 Potentially Affecting SSS Operability

The licensee's corrective actions included deleting the steps that allowed de-energization of valves CA-174 and CA-175 from the procedures for both units.

O8.4 (Closed) VIO 50-414/97-11-02:. Failure to Correctly Develop a DOI Replacement Plan and to Perform DOI Replacement Activities in Accordance with the Controlling Procedure.

The violation was issued because inappropriate electrical diagrams were referenced during the development of an isolation plan for replacing a failed digital optical isolator (DOI). As a result, control room operators had to mitigate a steam generator pressure transient that occurred when a flawed isolation plan was implemented and caused three main steam isolation valves to close. The licensee attributed the cause of the event to inadequate work practices and counseled the technician who developed the isolation plan. The licensee also provided training to all maintenance technicians through discussions between work group supervisors and their staff regarding the importance of using appropriate electrical drawings for determining an isolation scheme. In addition, maintenance procedures IP/0/A/3890/001 and IP/0/A/3840/003 were reviewed to identify the potential need for improvement and enhancements to IP/0/A/3840/003 were made. The inspector verified that these corrective actions were completed. This item is closed.

O8.5 (Closed) LER 50-413/98-012-00, 01: TS 3.0.3 Entry Due to Inoperability of Both Trains of Control Room Ventilation Caused by Improper System Isolation

This event was previously discussed in NRC Inspection Report 50-413,414/98-08. This event was caused by a breach of the control room area ventilation system's pressure boundary through an isolation damper that had been improperly secured in preparation for maintenance on the system. The damper (1CR-D-10) was listed in the tagout procedure (08-1187) and designated to be secured closed. However, the damper operator was of an unusual design, and neither visual aids nor guidance for damper operation were provided to indicate how to secure that damper and verify that it was in the secured position. As a result, operations personnel executing the tagout failed to recognize that they had incorrectly secured the damper in the closed position. This failure to properly implement the operations tagout procedure constitutes a violation of TS 6.8.1a and Regulatory Guide 1.33, Appendix A, Revision 2, section 3.p. This non-repetitive, licensee identified and corrected violation is characterized as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy, and is identified as NCV 50-413,414/98-12-04: Failure to Properly Implement Tagout Procedure Resulting in VC System Inoperability and a Dual-Unit Entry into TS 3.0.3.

As part of the licensee's corrective actions, damper 1CR-D-10 was color coded and marked to indicate how it should be secured. A training package was developed to inform operators about the proper method to accomplish the task. Licensed and non-licensed operators attended the training. A new related element has been added to the training and qualifications guide, which the operators are required to complete to satisfy their qualification requirements. These actions were verified by the inspectors.

Following this event, the licensee initiated an internal Event Investigation Team (EIT) to address the emerging trend involving the numerous ventilation system problems that occurred during the first half of 1998. (This trend was also discussed in NRC IR 50-413,414/98-08). The EIT report, dated July 17, 1998, found that the negative trend was generally caused by plant personnel lacking a thorough understanding of ventilation system TS requirements. Immediately following this event, the licensee set up an oversight team dedicated to reviewing all proposed work and configuration changes involving safety-related ventilation systems. Detailed pre-job briefings were also required prior to scheduled maintenance or unusual testing activities. The inspectors have observed these activities and will continue to monitor the licensee's progress in this area and assess corrective actions for the other events while closing their associated LERs. This LER is closed.

O8.6 (Closed) VIO 50-414/97-07-01: Inadequate Procedure Resulting in Loss of Spent Fuel Pool Cooling with Core Off-Loaded

The inspector verified the corrective actions as described in the licensee response dated June 23, 1997. Procedures PT/1/A/4200/01T and PT/2/A/4200/0T, Containment Penetration Valve Injection Water System Performance Test were revised to secure the penetration prior to draining the penetration. These changes were completed by Revision 44, approved on April 15, 1997, for Unit 1 and Revision 52, approved on April, 18, 1997, for Unit 2. In addition, other corrective actions taken to avoid future similar problems, as described in the response, were verified as completed. This violation is closed.

O8.7 (Closed) VIO 50-413/97-08-01: Inadequate Alarm Response Results in Inadequate and Untimely Corrective Action for Valve Operability Determination

(Closed) LER 50-413/97-002-00: Feedwater Containment Isolation Valve Inoperable

The violation and the LER are related to the same event. Corrective actions described in the violation response, dated July 22, 1997, and LER were verified to be completed. The violation was discussed previously in IR 50-413,414/97-014. It is noted that the LER and the violation were issued against Unit 1 docket but, the corrective actions apply to both units.

The corrective actions included resetting the nitrogen pressure setpoint to 2300-2350 psig from 2050-2150 psig. This change provides a greater margin between the alarm setpoint and the inoperable pressure limit. The alarm response procedure was revised to immediately declare the valve inoperable and have the nitrogen pressure checked within four hours of the alarm. Both the violation and the LER are closed.

## II. Maintenance

### M1 Conduct of Maintenance

M1.1 General Comments on the Conduct of Maintenance and Surveillance Activities (62707, 61726)

The inspectors observed portions of the following maintenance and surveillance activities:

- PT/2/A/4200/009A, Auxiliary Safeguards Test Cabinet Periodic Test, Revision 161
- PT/2/A/4250/003B, Auxiliary Feedwater Motor Driven Pump 2B Performance Test, Revision 027
- PT/2/A/4200/013E, CA Valve Inservice Test (QU), Revision 053
- PT/2/A/4450/005A, Containment Air Return Fan 2A and Hydrogen Skimmer Fan 2A Performance Test, Revision 40
- IP/2/A/3200/002A, Solid State Protection System (SSPS) Train A Periodic Testing, Revision 023

- IP/1/A/3200/002B, Solid State Protection System (SSPS) Train B Periodic Testing, Revision 027
- IP/0/A/3720/001, SCI Battery Charger Corrective Maintenance, Revision 11
- IP/0/A/3540/001A, SCI Inverter & Charger Capacitor Replacement Procedure, Revision 8
- OP/0/B/6500/015, Radwaste Chemistry Procedure for Discharging A Monitor Tank to the Environment, Revision 080
- OP/0/A/6500/080, EMF RP86A Output Modules, Revision 005
- HP/0/B/1004/004, Radioactive Liquid Waste Release, Revision 031
- PT/1/A/4600/01, RCCA Movement Test, Revision 28
- PT/2/A/4400/003A, Component Cooling (KC) Train 2A Performance Test, Revision 30
- IP/2/A/3144/001B, Calibration Procedure for Residual Heat Removal (ND) Miniflow Control Pressure Switches, Revision 9
- IP/0/A/3816/010, Barton Model 580 and 581 DP Switch Calibration, Revision 17
- IP/2/A/3144/001B, Calibration Procedure for ND Miniflow Control Pressure Switches, Revision 9

In general, the referenced maintenance and surveillance activities were performed well, with proper adherence to procedural compliance, equipment calibration, and radiation protection requirements.

## M8 **Miscellaneous Maintenance Issues** (92902)

M8.1 (Closed) LER 50-414/96-005: Unit 2 Standby Shutdown System Potentially Outside Design Basis

This LER, previously discussed in IR 50-413,414/98-08, described an event in which the licensee determined that Unit 2 potentially operated with the SSS outside of its design basis. The SSS degraded condition was related to clogged vent valve 2RC-116. This float-type vent valve located near the top of a 30-inch diameter RC system standpipe. The valve is relied upon to automatically remove air from the standpipe, which serves as an assured suction source for the TDAFWP during events requiring equipment operation from the SSF. The valve was found stuck in the closed position on July 10, 1996, and had been that way for an indeterminate amount of time because of impacted mud and corrosion internal to the valve. The licensee inspected the standpipe and found that some air had accumulated in the piping in the vicinity of the vent valve. However, the air was restricted to an elevation approximately one foot above where the TDAFWP suction pipe was connected. Thus, the licensee maintained that the operability of the TDAFWP and the SSS was not affected at that time. The licensee replaced the valve and added it and its Unit 1 counterpart to the preventative maintenance program to detect or prevent future clogging and degradation. These and other corrective actions were verified by the inspectors as described in IR 50-413,414/98-08.

The licensee determined that, although the quantity of air present in the standpipe at the time of discovery was insufficient to render the TDAFWP/SSS inoperable, periods of time could have existed prior to discovery when the standpipe had enough air present to impact TDAFWP/SSS operability. For maintenance purposes during refueling outages, the licensee had drained the RC piping to which the standpipe is connected. While it was drained, the licensee contended that the standpipe was full of air; and upon refilling the pipe with water, the air in the standpipe would be compressed if not allowed to vent through the clogged-shut valve 2RC-116. The licensee conservatively postulated that, in the past, the compressed air trapped in the standpipe was at an elevation that might have allowed it to enter the TDAFWP suction if the SSS was employed. The licensee's evaluation explained that the absence of air at the TDAFWP suction pipe elevation on July 10, 1996, was attributed to the entrapped air slowly being absorbed by the RC system during normal operation following the previously completed refueling outage.

The licensee determined that the degraded condition was ultimately caused by the failure to include pertinent information in design basis documents regarding the vent valve's impact on SSS operability, and the subsequent exclusion of the valve from the preventative maintenance program. The licensee concluded that the safety significance was minimized by the fact that, for security events, the risk significance of the SSS was associated with the reactor coolant pump seal injection function (which was not affected) and not the steam generator feedwater supply function. For other SSS-related events, including a fire or a station blackout, the need to have RC supplying the TDAFWP would likely be precluded by the short duration of the event and/or the availability of other sources of water.

IR 50-413,414/98-08 also discussed the need for further NRC review of TS Surveillance Requirement (SR) 4.7.13.5, and a determination of whether there were missed opportunities to identify the valve degradation while implementing the SR. The licensee implemented SR 4.7.13.5 by performing procedure PT/2/A/4350/022, CA Control From SSF Operability Test, Revision 11. This procedure verified that, upon demand, control power properly transferred from the main control room to the SSF. It also verified that various valves for which controls were provided at the SSF panel could be manipulated from there, including the TDAFWP trip and throttle valve; a TDAFWP steam supply valve (2SA-5); and valves 2CA-174, 175, and 178 connecting the TDAFWP suction to RC system piping. The inspectors reviewed the most recently completed copies of the Unit 1 and Unit 2 surveillance procedures and verified that all steps had been signed off. The inspectors concluded that, because valve 2RC-116 was a self-contained automatic vent valve with no controls provided at the SSF, its operability (or impact on SSS/TDAFWP operability) could not reasonably have been demonstrated while implementing SR 4.7.13.5. Hence, there were no further operability implications or missed opportunities identified by the inspectors.

The inspectors concluded that the licensee's determination that the SSS was potentially outside of its design basis prior to July 10, 1996, was conservative. No specific periods of inoperabilty or conditions outside the design basis were identified. The inspectors addressed maintenance rule implications and determined that the failure to monitor the performance or condition of valve 2RC-116 in accordance with 10 CFR 50.65 ("Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants") was identified and properly corrected just as the rule came into effect (also on July 10, 1996). No other regulatory issues were identified since the SSS is not designated as safety-related. This LER is closed.

M8.2 (Closed) IFI 50-413,414/97-07-03: Review Corrective Actions for Storage and Handling Assessment Findings

This IFI was opened to track the findings and recommendations from two assessments of motor storage and handling practices for electric motors. The first assessment, CTS-09-96 was completed December 2, 1996, and the findings and recommendation have been verified to be completed. The changes included revisions to site directives and enhancements to forms. The second assessment was SA-97-61 (CIV) (SRG), Assessment of Warehouse Material Condition, which was completed April 23, 1997. The findings of this assessment were verified to be completed. This IFI is closed.

## III. Engineering

### E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Unresolved Item (URI) 50-413,414/97-14-03: Noncompliance with 10 CFR 50, Appendix A, General Design Criteria 57, Closed System Isolation Valves

This URI had been opened to address a licensee-identified design oversight associated with Unit 1 and Unit 2 containment penetrations M-261 (B Main Steam to the TDAFWP) and M-393 (C Main Steam to TDAFWP). The two penetrations did not comply with 10 CFR 50, Appendix A, General Design Criteria (GDC) 57, in that the lines providing main steam to the pump turbines were not provided with valves that were either automatic, locked closed or capable of remote manual operation. The two containment isolation valves associated with these lines, 1SA-1 and 1SA-4, were manual gate valves that were locked open to maintain the TDAFWP operable. The licensee submitted a letter to the NRC on September 2, 1997, requesting exemption from the GDC on the basis that the as-designed configuration was necessary to maintain the TDAFWP operable, and that providing motor operators to the two valves would introduce an additional failure mode which could degrade the reliability of the TDAFWP to mitigate an accident. The licensee stated, as further basis, that the valves could be manually closed as necessary to isolate a faulted steam line, unless they were inaccessible due to post-accident environmental conditions, in which case associated stop check valves could be used. The licensee stated in its submittal that the time needed to isolate steam using SA-1 and SA-4, or their associated stop check valves, had been factored into accident analyses and dose calculations referenced in the UFSAR.

The NRC granted the licensee the exemption via a letter dated December 29, 1998. In that letter, the NRC concluded that literal compliance with the operational requirements of GDC 57 was not desirable, as it potentially conflicted with the existing TS related to the TDAFWP and was not necessary to achieve the underlying purpose of the rule (to provide a reliable means for isolating the penetration). NRC issuance of the exemption effectively corrected the GDC noncompliance.

The Catawba design basis was described in the UFSAR. The inspectors reviewed UFSAR Section 3.1, "Conformance With General Design Criteria", and noted for Criterion 57, that the licensee provided the following discussion: "Each line that penetrates the reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere has at least one containment isolation valve located outside the containment as close to the containment as practical." Implicit in that statement was the understanding that the valves complied with GDC 57. The only exception to the criterion taken in the UFSAR was for the residual heat removal system. The inspectors determined that the licensee's failure to effectively translate the design basis and applicable regulatory requirements for the TDAFWP main steam supply piping into specifications, drawings, and procedures prior to NRC issuance of the GDC exemption constituted a violation of 10 CFR 50, Appendix B, Criterion III (Design Control). However, this non-repetitive, licensee identified and corrected violation is identified as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy, and is identified as NCV 50-413,414/98-12-05: Failure to Comply with GDC 57 for Main Steam Supply Piping to the TDAFWPs. This issue is closed.

## IV. Plant Support

### P7 Quality Assurance in EP Activities

P7.1 Regulatory Audit, SA-98-101, Emergency Planning (EP) - General Comments (40500)

The inspectors reviewed regulatory audit SA-98-101, Emergency Planning, which was conducted by the licensee. Following the review of the audit, the inspectors concluded that the licensee's audit was effective in identifying issues and/or areas for improvement. The inspectors verified that the licensee took appropriate action to address issues that were identified.

### F1 Control of Fire Protection Activities

F1.1 Fire Brigade Response to Hydrogen Cylinder Rupture Disc Failure

a. Inspection Scope (71750)

The fire brigade responded to reports of an open hydrogen cylinder relief valve on January 5, 1999. The inspectors performed a visual inspection of the hydrogen cylinder and the hydrogen shelter located in the plant yard. The inspectors also reviewed the UFSAR, design basis documentation and system drawings to understand the system's function and the impact of the rupture disc failure to plant safety.

b. Observations and Findings

The fire brigade responded to the location of the hydrogen cylinder within fifteen minutes. The inspectors reviewed the licensee's Emergency Plan to determine if the event met any emergency classification criteria and determined that, since the event did not occur in the plant (as defined by the Emergency Plan), a Notice of Unusual Event was not required. There were no confirmed reports of an actual fire at the location and the inspectors did not identify any signs of fire damage at the affected hydrogen cylinder or in the general vicinity immediately following the event. The inspectors noted that the cylinder rupture discs relieve to a hard-piped tailpipe, which directs the highly combustible gas out of the shelter and to the shelter's roof, where it is then released to atmosphere, thereby reducing the chances of a fire hazard in the shelter. The shelter is located inside the protected area, but sufficiently distanced from any safety-related plant equipment.

In addition to other functions, the hydrogen bulk storage system, which consists of six hydrogen cylinders, supplies the Hydrogen Blanket (GB) system. The GB system provides a continuous hydrogen supply to the Unit 1 and Unit 2 volume control tanks (VCT) for reactor coolant system oxygen scavenging during all operational modes. Normally, four tanks are aligned to a common header that extends into the auxiliary building, where it interfaces with the chemical and volume control system; the remaining two cylinders are normally in standby. The licensee determined that a rupture disc associated with one of the in-service tanks failed. The licensee immediately isolated the affected tank from the common header. According to engineering personnel, the pressure in the common header had dropped from approximately 1000 psig to approximately 700 psig before the affected tank was isolated from it. This did not affect the system's ability to provide a continuous supply of hydrogen to the VCTs. The licensee indicated that a planned corrective action was to inspect the rupture disc when it is removed for replacement to determine the cause of the failure and if any generic concerns apply to the other hydrogen cylinders.

c. Conclusions

The inspectors concluded that the licensee was adequately addressing the hydrogen storage system rupture disk failure. No safety or regulatory concerns were identified.

## V. Management Meetings

### X1 Exit Meeting Summary

The inspector presented the inspection results to members of licensee management at the conclusion of the inspection on January 28, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Beagles, Safety Assurance Manager
M. Boyle, Radiation Protection Manager
S. Bradshaw, Safety Assurance Manager
G. Gilbert, Regulatory Compliance Manager
P. Glover, Operations Superintendent
P. Herran, Engineering Manager
R. Jones, Station Manager
G. Peterson, Catawba Site Vice-President
F. Smith, Chemistry Manager
R. Parker, Maintenance Manager

## INSPECTION PROCEDURES USED

| | |
|---|---|
| IP 40500: | Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems |
| IP 61726: | Surveillance Observation |
| IP 62707: | Maintenance Observation |
| IP 71707: | Plant Operations |
| IP 71750: | Plant Support Activities |
| IP 92901: | Followup - Operations |
| IP 92902: | Followup - Maintenance |
| IP 92903: | Followup - Engineering |
| IP 93702: | Prompt Onsite Response to Events at Operating Power Reactors |

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-414/98-12-01 | IFI | Relay Failures Cause Two CA Pumps to be Declared Inoperable (Section O2.2) |
| 50-413, 414/98-12-02 | EEI | Auxiliary Feedwater System Outside Design Basis due to Potential Adverse Interaction Between CACST and CA During Swapover (Section O8.2) |
| 50-413,414/98-12-03 | VIO | Failure to Conduct an Adequate 10 CFR 50.59 Safety Evaluation for Changes to Procedures AP-6 and AP-17 Potentially Affecting SSS Operability (Section O8.3) |
| 50-413,414/98-12-04 | NCV | Failure to Properly Implement Tagout Procedure Resulting in VC System Inoperability and a Dual-Unit Entry into TS 3.0.3 (Section O8.5) |

| | | |
|---|---|---|
| 50-413,414/98-12-05 | NCV | Failure to Comply with GDC 57 for Main Steam Supply Piping to the TDAFWPs (Section E8.1) |

Closed

| | | |
|---|---|---|
| 50-413/97-011 | LER | ESF Actuation due to Reactor Coolant System Leakage from Loop Drain Valves (Section O8.1) |
| 50-413/97-03 | LER | Auxiliary Feedwater System Found Outside of Design Basis (Section O8.2) |
| 50-413,414/97-08-07 | URI | Potential Air Binding of Auxiliary Feedwater Pumps (Section O8.2) |
| 50-413,414/98-09-02 | URI | Potentially Inadequate Procedures Not Ensuring the Operability of the SSF (Section O8.3) |
| 50-414/97-11-02 | VIO | Failure to Correctly Develop a DOI Replacement Plan and to Perform DOI Replacement Activities in Accordance with the Controlling Procedure (Section O8.4) |
| 50-413/98-012-00, 01 | LER | TS 3.0.3 Entry Due to Inoperability of Both Trains of Control Room Ventilation Caused by Improper System Isolation (Section O8.5) |
| 50-414/97-07-01 | VIO | Inadequate Procedure Resulting in Loss of Spent Fuel Pool Cooling with Core Off-Loaded (Section O8.6) |
| 50-413/97-08-01 | VIO | Inadequate Alarm Response Results in Inadequate and Untimely Corrective Action for Valve Operability Determination (Section O8.7) |
| 50-413/97-002-00 | LER | Feedwater Containment Isolation Valve Inoperable (Section O8.7) |
| 50-414/96-005-00 | LER | Unit 2 Standby Shutdown System Potentially Outside Design Basis (Section M8.1) |
| 50-413,414/97-07-03 | IFI | Review Corrective Actions for Storage and Handling Assessment Findings (Section M8.2) |
| 50-413,414/97-14-03 | URI | Noncompliance with 10 CFR 50, Appendix A, General Design Criteria 57, Closed System Isolation Valves (Section E8.1) |

## LIST OF ACRONYMS USED

| | | |
|---|---|---|
| CA | - | Auxiliary Feedwater (licensee's system designation) |
| CACST | - | Auxiliary Feedwater Condensate Storage Tank |
| CCW | - | Component Cooling Water |
| CFR | - | Code of Federal Regulations |
| CSS | - | Condensate Storage System |
| DBD | - | Design Basis Document |
| DOI | - | Digital Optical Isolator |
| DP | - | Differential Pressure |
| EEI | - | Apparent Violation |
| EIT | - | Event Investigation Team |
| EP | - | Emergency Planning |
| ESF | - | Engineered Safety Feature |
| GB | - | Hydrogen Blanket (licensee's system designation) |
| GDC | - | General Design Criteria |
| IR | - | Inspection Report |
| LCO | - | Limiting Condition for Operation |
| LER | - | Licensee Event Report |
| LOOP | - | Loss of Offsite Power |
| NCV | - | Non-Cited Violation |
| ND | - | Residual Heat Removal (licensee's system designation) |
| NLO | - | Non-licensed Operator |
| NOUE | - | Notification Of Unusual Event |
| PDR | - | Public Document Room |
| P&IDs | - | Piping and Instrumentation Drawings |
| PIP | - | Problem Investigation Process |
| psig | - | Pounds per Square Inch Gauge |
| RC | - | Condenser Circulating Water (licensee's system designation) |
| RCCA | - | Rod Cluster Control Assembly |
| RCS | - | Reactor Coolant System |
| RN | - | Nuclear Service Water (licensee's system designation) |
| SR | - | Surveillance Requirement |
| SSF | - | Standby Shutdown Facility |
| SSPS | - | Solid State Protection System |
| SSS | - | Standby Shutdown System |
| TDAFWP | - | Turbine Driven Auxiliary Feedwater Pump |
| TS | - | Technical Specification |
| TSAIL | - | Technical Specification Action Item Log |
| UFSAR | - | Updated Final Safety Analysis Report |
| URI | - | Unresolved Item |
| USQ | - | Unreviewed Safety Question |
| UST | - | Upper Surge Tank |
| VCT | - | Volume Control Tank |
| VIO | - | Violation |
| WO | - | Work Order |