APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-313/89-17 Operating Licenses: DPR-51
50-368/89-17 NPF-6

Dockets: 50-313
50-368

Licensee: Arkansas Power & Light Company (AP&L)
P.O. Box 551
Little Rock, Arkansas 72203

Facility Name: Arkansas Nuclear One (ANO), Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: April 17-21, 1989

Inspectors: P. C. Wagner 5/9/89
P. C. Wagner, Reactor Inspector, Plant Systems Section, Division of Reactor Safety — Date

L D Gilbert 5/9/89
L. D. Gilbert, Reactor Inspector, Materials and Quality Programs Section, Division of Reactor Safety — Date

P C Wagner 5/9/89
for M. E. Murphy, Reactor Inspector, Test Programs Section, Division of Reactor Safety — Date

Approved: T. Barnes 5/10/89
T. Barnes, Chief, Materials and Quality Programs Section, Division of Reactor Safety — Date

Inspection Summary

Inspection Conducted April 17-21, 1989 (Report 50-313/89-17; 50-368/89-17)

Areas Inspected: Routine, unannounced inspection of the licensee's implementation of an integrated corrective action program, and a special inspection of the followup actions in response to the Unit 2 extraction steam line break which occurred on April 18, 1989. During the corrective action program inspection, the NRC inspectors reviewed germane procedures, QA audits, and documentation packages. The special inspection included physically checking the portion of extraction steam line that failed and discussing the licensee's planned corrective actions.

Results: During the inspection, no violations or deviations were identified. The NRC inspectors determined that there was a timeliness problem with the implementation of the new corrective action program and noted some problems with the completion of the controlling procedures. The NRC inspectors also discussed the advisability of implementing an aggressive trending program for identified problems and their resolution.

The NRC inspectors found the licensee's actions in response to the extraction steam line break to be acceptable and had no questions in that area.

DETAILS

1. Persons Contacted

AP&L

*C. Anderson, In-House Events Analysis Supervisor
*B. Baker, Plant Modification Manager
*T. Baker, Technical Support Manager
*W. Converse, Operations Assessment Superintendent
*E. Ewing, General Manager, Plant Support
*H. Greene, QA Superintendent
*R. Lane, Manager, ANO Engineering
*J. Levine, Executive Director, Nuclear Operations
*D. Lomax, Plant Licensing Supervisor
+ S. McGregor, Superintendent, Engineering Services
*J. McWilliams, Manager, Maintenance
+*P. Michalk, Licensing Engineer
C. Turk, Superintendent, Nuclear Engineering

NRC Personnel

*L. J. Callan, Director, Division of Reactor Projects, Region IV
+*R. Haag, Resident Inspector, ANO
*A. Howell, Project Engineer, Region IV

+ Denotes personnel who attended the exit meeting on April 20, 1989.
*Denotes personnel who attended the exit meeting on April 21, 1989.

The NRC inspectors also contacted and interviewed other AP&L operations, maintenance, and engineering personnel during the course of the inspection.

2. Corrective Actions - Units 1 and 2 (92720)

The NRC identified weaknesses with the corrective action program being implemented at ANO during late 1987. These weaknesses were documented in NRC Inspection Reports 50-313/87-20; 50-368/87-20 and 50-313/87-26; 50-368/87-26. As a result of those findings, and NRC management concerns, AP&L evaluated the ANO corrective action program (CAP) and committed to program improvements in the areas of condition identification, timeliness of review and corrective action, root cause analysis, and trending. The licensee presented the program improvements to the NRC during a management meeting which was held in the NRC Region IV offices on February 4, 1988. This inspection was performed in an effort to evaluate the effectiveness of the CAP that was presented to the NRC.

In order to ensure that the "improved" CAP would resolve the earlier NRC concerns, the NRC inspectors reviewed pertinent procedures, Quality

Assurance (QA) Audits, and a sample of both completed and in-process documentation packages.

a. Procedure Reviews

The NRC inspectors reviewed Station Administrative Procedure 1000.104, "Condition Reporting and Corrective Actions," Revision 3, dated January 21, 1989. This procedure provided guidance to all personnel on how to document "undesirable conditions at ANO," and on how the improved CAP was to be implemented. The procedure also provided instructions on determining operability and reportability, establishing significance and priority, and in closing the documentation package when the corrective actions were completed. The procedure included the various forms which made up the Condition Report (CR) documentation (Forms 1000.104A through K).

The NRC inspectors found the above procedure to be adequate in providing the framework for the CAP, but discussed the apparent need for additional guidance in the areas of determining reportability, operability, and cause/root cause. The NRC inspectors were informed that additional guidance in determining operability was being provided by a new procedure which was to become effective on April 30, 1989. Because timeliness in making operability determinations had been a problem, the new procedure (1000.116, "Operability Determination") required the Shift Technical Advisor (STA) to make a determination within 24 hours of the request for such a determination from the Shift Operations Supervisor (SOS). If the STA concluded that an engineering evaluation was needed, a documented interim determination by the STA that the system or component would remain fully functional during the time required for the evaluation was required. The NRC inspectors determined that these provisions would help to preclude long-term conditions during which no documented basis existed for continued operations with systems or components which were being evaluated for operability.

The NRC inspectors noted that trending of identified conditions was not delineated by the above procedures and questioned how this was being accomplished. The NRC inspectors were informed that the In-House Events Analysis Group (IHEA) was trending the CRs and providing a periodic report to AP&L management. The NRC inspectors reviewed existing IHEA reports and found them to be acceptable; however, the NRC inspectors remained concerned that the trending program was not required by procedure.

The NRC inspectors discussed their concerns over the CAP implementation with the involved AP&L personnel and reiterated their concerns during the April 21, 1989, exit meeting.

The NRC inspectors determined that the new procedures provided an improved method of identifying, reporting, and correcting undesirable conditions at ANO. The new CAP was also found to provide an acceptable framework for resolving previously identified NRC concerns. Problems identified with the implementation of the CAP are discussed in subparagraph c, below.

No violations or deviations were identified.

b. QA Audits

The NRC inspectors reviewed QA Audits QAP-10-88, "Corrective Action," first half dated August 19, 1988, and second half dated March 29, 1989. Since the first half audit was conducted shortly after the initiation of the new CAP, the findings were inconclusive. The second audit was more productive and concluded that: "Management attention has not been adequately given to the timely completion of:

"° Condition report corrective actions
"° 'For further evaluation' operability/reportability concerns
"° Managers and IHEA root cause determinations
"° Transmittal of completed records to ANO DCC
"° Transmittal of CR's from security to IHEA"

The report went on to identify the most significant weakness of the new CAP as "The failure to complete assigned corrective actions within the assigned time frames." The NRC inspectors review of selected condition report packages substantiated the QA audit findings.

The NRC inspectors found the QA Audit to be effective in meeting the objectives of the QA program and in providing insight to the licensee management on areas requiring improvement.

No violations or deviations were identified.

c. Documentation Package Reviews

The NRC inspectors selected a number of CRs from the licensee provided tabulation which listed approximately 850 CRs for Unit 1, 525 CRs for Unit 2, and 100 CRs common to both Units. Some of the CRs were closed while others remained open for various reasons. The NRC inspectors also selected some Reports of Abnormal Conditions (RACs) which remained open from the previous corrective action systems. A partial listing of the RACs and CRs that were reviewed is contained in the attachment to this report.

The NRC inspectors noted that frequent delays in documenting both operability and reportability determinations were being made while waiting for "further evaluation." The NRC inspectors also noted that the CR Forms were not always properly completed, especially in the area of cause/root cause. The CR procedure required a cause for each condition and a root cause for those conditions judged to be significant; a root cause was not always provided for conditions that had been determined to be significant. The NRC inspectors discussed these observations with licensee personnel and also discussed questions they had on the reviewed RACs and CRs. The following are examples of problems observed:

(1) RAC-2-86112

This RAC was initiated on June 24, 1986, to document discrepancies between the ANO-2 Technical Specification required protective system and safeguards system setpoints and the values calculated to be appropriate by Combustion Engineering Corporation (CE). The NRC inspectors, on April 19, 1989, were unable to determine from the available information if the condition had ever been evaluated. A telephone conference call was conducted on April 21, 1989, at which AP&L personnel explained that CE engineers had utilized an inappropriate containment pressure transmitter error value in their calculation. (These transmitters had been replaced at ANO-2 with a different brand which had lower errors.) AP&L personnel explained that the proper transmitter error values had been substituted into the CE calculation for the high containment pressure trip setpoint when the CE error was detected and that the resulting setpoint was consistent with the implemented value. The RAC had remained open pending a determination of its reportability.

The AP&L personnel also informed the NRC inspectors that the implemented high-high containment pressure setpoint was verified to be appropriate on April 20, 1989, by using a method similar to that used earlier for the high pressure setpoint.

This RAC was transferred to the new CAP system by the initiation of CR-2-89-161 on April 19, 1989.

The NRC inspectors found the processing of this RAC to be an additional example of the NRC concerns with the previous corrective action systems at ANO and were troubled that these old issues (RACs) had not all been incorporated into the new CAP. (A few of the old RACs had been transferred to new CRs in the weeks preceding the inspection, but numerous other RACs remained without actions being finalized.)

(2) CR-1-88-239

This CR documented a wiring error that was discovered on September 21, 1988, during the licensee's "as-building" of the essential 4160 volt switchgear-A4. The wiring error caused one of the trip paths for the emergency diesel generator (EDG) output circuit breaker to be inoperable. This condition could have caused an overload and loss of the EDG if it was being

Inspection Summary

Inspection Conducted April 17-21, 1989 (Report 50-313/89-17; 50-368/89-17)

Areas Inspected: Routine, unannounced inspection of the licensee's implementation of an integrated corrective action program, and a special inspection of the followup actions in response to the Unit 2 extraction steam line break which occurred on April 18, 1989. During the corrective action program inspection, the NRC inspectors reviewed germane procedures, QA audits, and documentation packages. The special inspection included physically checking the portion of extraction steam line that failed and discussing the licensee's planned corrective actions.

Results: During the inspection, no violations or deviations were identified. The NRC inspectors determined that there was a timeliness problem with the implementation of the new corrective action program and noted some problems with the completion of the controlling procedures. The NRC inspectors also discussed the advisability of implementing an aggressive trending program for identified problems and their resolution.

The NRC inspectors found the licensee's actions in response to the extraction steam line break to be acceptable and had no questions in that area.

DETAILS

1. Persons Contacted

   AP&L

   *C. Anderson, In-House Events Analysis Supervisor
   *B. Baker, Plant Modification Manager
   *T. Baker, Technical Support Manager
   *W. Converse, Operations Assessment Superintendent
   *E. Ewing, General Manager, Plant Support
   *H. Greene, QA Superintendent
   *R. Lane, Manager, ANO Engineering
   *J. Levine, Executive Director, Nuclear Operations
   *D. Lomax, Plant Licensing Supervisor
   + S. McGregor, Superintendent, Engineering Services
   *J. McWilliams, Manager, Maintenance
   +*P. Michalk, Licensing Engineer
   C. Turk, Superintendent, Nuclear Engineering

   NRC Personnel

   *L. J. Callan, Director, Division of Reactor Projects, Region IV
   +*R. Haag, Resident Inspector, ANO
   *A. Howell, Project Engineer, Region IV

   + Denotes personnel who attended the exit meeting on April 20, 1989.
   *Denotes personnel who attended the exit meeting on April 21, 1989.

   The NRC inspectors also contacted and interviewed other AP&L operations, maintenance, and engineering personnel during the course of the inspection.

2. Corrective Actions - Units 1 and 2 (92720)

   The NRC identified weaknesses with the corrective action program being implemented at ANO during late 1987. These weaknesses were documented in NRC Inspection Reports 50-313/87-20; 50-368/87-20 and 50-313/87-26; 50-368/87-26. As a result of those findings, and NRC management concerns, AP&L evaluated the ANO corrective action program (CAP) and committed to program improvements in the areas of condition identification, timeliness of review and corrective action, root cause analysis, and trending. The licensee presented the program improvements to the NRC during a management meeting which was held in the NRC Region IV offices on February 4, 1988. This inspection was performed in an effort to evaluate the effectiveness of the CAP that was presented to the NRC.

   In order to ensure that the "improved" CAP would resolve the earlier NRC concerns, the NRC inspectors reviewed pertinent procedures, Quality

Assurance (QA) Audits, and a sample of both completed and in-process documentation packages.

a. <u>Procedure Reviews</u>

The NRC inspectors reviewed Station Administrative Procedure 1000.104, "Condition Reporting and Corrective Actions," Revision 3, dated January 21, 1989. This procedure provided guidance to all personnel on how to document "undesirable conditions at ANO," and on how the improved CAP was to be implemented. The procedure also provided instructions on determining operability and reportability, establishing significance and priority, and in closing the documentation package when the corrective actions were completed. The procedure included the various forms which made up the Condition Report (CR) documentation (Forms 1000.104A through K).

The NRC inspectors found the above procedure to be adequate in providing the framework for the CAP, but discussed the apparent need for additional guidance in the areas of determining reportability, operability, and cause/root cause. The NRC inspectors were informed that additional guidance in determining operability was being provided by a new procedure which was to become effective on April 30, 1989. Because timeliness in making operability determinations had been a problem, the new procedure (1000.116, "Operability Determination") required the Shift Technical Advisor (STA) to make a determination within 24 hours of the request for such a determination from the Shift Operations Supervisor (SOS). If the STA concluded that an engineering evaluation was needed, a documented interim determination by the STA that the system or component would remain fully functional during the time required for the evaluation was required. The NRC inspectors determined that these provisions would help to preclude long-term conditions during which no documented basis existed for continued operations with systems or components which were being evaluated for operability.

The NRC inspectors noted that trending of identified conditions was not delineated by the above procedures and questioned how this was being accomplished. The NRC inspectors were informed that the In-House Events Analysis Group (IHEA) was trending the CRs and providing a periodic report to AP&L management. The NRC inspectors reviewed existing IHEA reports and found them to be acceptable; however, the NRC inspectors remained concerned that the trending program was not required by procedure.

The NRC inspectors discussed their concerns over the CAP implementation with the involved AP&L personnel and reiterated their concerns during the April 21, 1989, exit meeting.

The NRC inspectors determined that the new procedures provided an improved method of identifying, reporting, and correcting undesirable conditions at ANO. The new CAP was also found to provide an acceptable framework for resolving previously identified NRC concerns. Problems identified with the implementation of the CAP are discussed in subparagraph c, below.

No violations or deviations were identified.

b. QA Audits

The NRC inspectors reviewed QA Audits QAP-10-88, "Corrective Action," first half dated August 19, 1988, and second half dated March 29, 1989. Since the first half audit was conducted shortly after the initiation of the new CAP, the findings were inconclusive. The second audit was more productive and concluded that: "Management attention has not been adequately given to the timely completion of:

"° Condition report corrective actions
"° 'For further evaluation' operability/reportability concerns
"° Managers and IHEA root cause determinations
"° Transmittal of completed records to ANO DCC
"° Transmittal of CR's from security to IHEA"

The report went on to identify the most significant weakness of the new CAP as "The failure to complete assigned corrective actions within the assigned time frames." The NRC inspectors review of selected condition report packages substantiated the QA audit findings.

The NRC inspectors found the QA Audit to be effective in meeting the objectives of the QA program and in providing insight to the licensee management on areas requiring improvement.

No violations or deviations were identified.

c. Documentation Package Reviews

The NRC inspectors selected a number of CRs from the licensee provided tabulation which listed approximately 850 CRs for Unit 1, 525 CRs for Unit 2, and 100 CRs common to both Units. Some of the CRs were closed while others remained open for various reasons. The NRC inspectors also selected some Reports of Abnormal Conditions (RACs) which remained open from the previous corrective action systems. A partial listing of the RACs and CRs that were reviewed is contained in the attachment to this report.

The NRC inspectors noted that frequent delays in documenting both operability and reportability determinations were being made while waiting for "further evaluation." The NRC inspectors also noted that the CR Forms were not always properly completed, especially in the area of cause/root cause. The CR procedure required a cause for each condition and a root cause for those conditions judged to be significant; a root cause was not always provided for conditions that had been determined to be significant. The NRC inspectors discussed these observations with licensee personnel and also discussed questions they had on the reviewed RACs and CRs. The following are examples of problems observed:

(1) RAC-2-86112

This RAC was initiated on June 24, 1986, to document discrepancies between the ANO-2 Technical Specification required protective system and safeguards system setpoints and the values calculated to be appropriate by Combustion Engineering Corporation (CE). The NRC inspectors, on April 19, 1989, were unable to determine from the available information if the condition had ever been evaluated. A telephone conference call was conducted on April 21, 1989, at which AP&L personnel explained that CE engineers had utilized an inappropriate containment pressure transmitter error value in their calculation. (These transmitters had been replaced at ANO-2 with a different brand which had lower errors.) AP&L personnel explained that the proper transmitter error values had been substituted into the CE calculation for the high containment pressure trip setpoint when the CE error was detected and that the resulting setpoint was consistent with the implemented value. The RAC had remained open pending a determination of its reportability.

The AP&L personnel also informed the NRC inspectors that the implemented high-high containment pressure setpoint was verified to be appropriate on April 20, 1989, by using a method similar to that used earlier for the high pressure setpoint.

This RAC was transferred to the new CAP system by the initiation of CR-2-89-161 on April 19, 1989.

The NRC inspectors found the processing of this RAC to be an additional example of the NRC concerns with the previous corrective action systems at ANO and were troubled that these old issues (RACs) had not all been incorporated into the new CAP. (A few of the old RACs had been transferred to new CRs in the weeks preceding the inspection, but numerous other RACs remained without actions being finalized.)

(2) CR-1-88-239

This CR documented a wiring error that was discovered on September 21, 1988, during the licensee's "as-building" of the essential 4160 volt switchgear-A4. The wiring error caused one of the trip paths for the emergency diesel generator (EDG) output circuit breaker to be inoperable. This condition could have caused an overload and loss of the EDG if it was being tested when a loss of offsite power occurred, concurrent with an engineered safety features actuation signal. The condition was determined to be reportable by the SOS and the Department Manager, but to be not reportable by the Licensing Department. The Plant Safety Committee (PSC) recommended that the condition not be reported. The condition was judged to have existed since the initial construction installation.

Although the condition was determined to be not significant because only one EDG was affected, and the appropriate "cause" box had been checked on Form 1000.104F, a "root cause" was provided. This root cause stated that "the condition can be attributed to insufficient procedures to ensure operability of electrical equipment controls."

A Job Order (J.O. 00768226) was completed on October 29, 1988, to correct and test the wiring for the circuit breaker. The CR remained open for completion of the additional corrective action to "develop procedures to verify operability of all 4160 and 6900 switchgear controls."

The NRC inspectors expressed their concern over the appropriateness of the determination to not report the above condition, especially in light of the additional wiring error detected in Switchgear A4 (CR-1-88-251) and the wiring error detected in Switchgear A3 (CR-1-88-324). In addition, four termination problems were detected during the "as-building" of the A3 and A4 switchgear, each of which could have lead to failure of the associated device. The NRC inspectors also discussed their observations about the appropriate cause/root cause determinations being provided for a condition, and the adequacy of those determinations.

(3) RAC-2-88074

This RAC, dated March 25, 1988, reported hanger and pipe deformation due to thermal growth. This RAC was marked for further evaluation to determine reportability. As of this inspection, the reportability determination had not been made and the RAC had not been converted to the CR system.

(4) CR-2-88-0015

This CR was written to document a long-term problem with the loss of the volume control tank (VCT) level indication without an accompanying low level alarm. This had caused, on various occasions, the loss of the charging pumps due to air binding. The root cause was identified in 1983 as a design problem with the level detectors having a common reference leg so that a loss of reference leg caused both detectors to sense an erroneous normal level when the VCT was actually empty. To correct this problem the licensee has issued a DCP which is scheduled to be accomplished during the next refueling.

(5) CR-2-88-0027 and CR-2-88-0069

These CRs were written in June 1988 to document the lift of one pressurizer code safety relief valve on June 6 and the lift of the second valve on June 23. The plant was at normal operating pressure and temperature and at 100 percent power. On CR-0069, the event was marked "significant" but only "cause" was marked on Form 1000.104F. On CR-0027, the event was marked "significant" but no mark was made on Form 1000.104F. What was apparently a root cause was written up on this form, but since no conclusion was drawn, there was no identified corrective action. The NRC inspectors were told that these CRs are still open and are being reevaluated.

The NRC inspectors concluded that this area warrants further evaluation and recommended to NRC management that additional inspection activity be conducted as the CAP implementation progresses.

3. Steam Extraction Line Rupture Event - Unit 2 (93702)

The NRC inspector observed the high pressure turbine extraction steam line that ruptured on April 18, 1989. The steam line rupture was approximately 180 degrees around the 14-inch diameter pipe and 2 inches below the turbine nozzle to pipe weld. The original thickness of the pipe was 3/8-inch nominal wall and had been eroded to less than 1/32 inch in the area where failure occurred. The cause for the preferential erosion has been determined to be a step on the internal diameter of the pipe which resulted from a pipe to nozzle mismatch. The high pressure turbine has four extraction steam lines of which two are 14-inch diameter and two are 10-inch diameter. The three lines which did not rupture were inspected for wall thinning using ultrasonic thickness measuring equipment. The other 14-inch line was measured at less than 0.100-inch remaining wall thickness and will be replaced since the minimum design wall thickness required was 0.267-inch. The two 10-inch lines were measured and determined to have sufficient wall thickness; however, the licensee was also considering replacing them. The original material for the extraction steam system was a carbon steel material while the replacement material was a low alloy steel. The licensee had a wall thickness monitoring program for systems susceptible to erosion/corrosion. Although much of the pipe downstream of the rupture had been replaced because of wall thinning which had been detected during the previous outage, the area which ruptured was neither suspected of wall thinning nor measured. The monitoring program for wall thinning of pipe was based on calculated flow rates, piping geometries, and past experience. The licensee also used the EPRI "CHEC" computer program to assist in determining which areas in single-phase piping systems were most susceptible to erosion and/or corrosion. The licensee was also working with EPRI to utilize the newly developed "CHECMATE" computer program for two-phase piping systems. The licensee's wall thinning monitoring program had included the steam extraction lines in the selection for the next outage. The selection also included, for the first time, components in safety-related piping systems, such as, the main steam and main feedwater piping systems.

No violations or deviations were identified.

4. Exit Meeting (30703)

Exit meetings were conducted April 20 and 21, 1989, with the licensee representatives identified in paragraph 1 of this report. No written material was provided to the licensee by the NRC inspectors during this reporting period. This licensee did not identify, as proprietary, any of the materials provided to, or reviewed by, the NRC inspectors during this inspection. During these meetings, the NRC inspectors summarized the scope and findings of the inspection.

ATTACHMENT
LIST OF DOCUMENTS REVIEWED

Number	Subject
RAC-2-85200,	NQ Power Supply
RAC-2-86112,	PPS Limits Not Per Calculation
RAC-2-86201,	Incorrect Electrical Splices
CR-1-88-191,	Service Water Flow Rates Low
CR-1-88-239,	Jumper Not Installed in Switchgear A4
CR-1-88-245,	Loose Wire in Switchgear Cubicle A-408
CR-1-88-282,	Motor Feeder Cable Failure
CR-1-88-284,	Motor Feeder Cable Failure
CR-1-88-305,	Wrong Overcurrent Relay Taps
CR-1-88-324,	Wiring Not Per Drawing
CR-1-88-337,	Bad Crimp on Terminal Lug
CR-1-88-344,	Cracks in EFW Pump Impeller
CR-1-89-089,	Solenoid Coil Age Over Qualified Lifetime
CR-1-89-137,	480 Volt Circuit Breaker Would Not Close
CR-1-89-151,	480 Volt Circuit Breaker Would Not Close
CR-1-89-228,	Damper Seal Age Over Qualified Lifetime
CR-2-88-0011,	Charging Pump "C" - Air Bound
CR-2-88-0015,	Loss of VCT Level
CR-2-88-0018,	Sporadic Vibration & Loose Parts Monitor Alarms
CR-2-88-0021,	Charging Pumps - Packing Leaks
CR-2-88-0023,	Fuel Element Leakage Indicated
CR-2-88-0027,	Pressurizer Relief Valve Lift
CR-2-88-0069,	Pressurizer Relief Valve Lift
CR-2-88-0115,	Potential Failure of Kapton Diaphragm (Part 21)
CR-2-88-0149,	RCP Breaker Failed to Close
CR-2-88-0166,	Air System Moisture Test Failed
CR-2-88-0167,	Spare Cards Not Available
CR-2-88-0175,	Charging Pump Air Binding
CR-2-88-0244,	Missed Surveillance Test
CR-2-88-0335,	Reactor Trip From ESFAS Surveillance Test
CR-2-88-0343,	MSSV Response During Reactor Trip
CR-C-88-007,	Fire Water Pump Diesel Without Coolant
CR-C-88-029,	SPDS Computer Cooler Failures
CR-C-88-039,	Jumper for Connecting Offsite Power
CR-C-88-048,	Problems with HFA Relays
CR-C-88-049,	Inoperable Fire Door in October 31, 1986