UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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March 13, 2000

Mr. John P. Cowan, Vice President
Nuclear Operations
Florida Power Corporation
ATTN: Manager Nuclear Licensing (NA1B)
Crystal River Energy Complex
15760 West Power Line Street
Crystal River, FL 34428-6708

SUBJECT: NRC INSPECTION REPORT 50-302/99-09

Dear Mr. Cowan:

This refers to the inspection conducted on December 26 through February 12, 2000, at the Crystal River facility. The enclosed report presents the results of this inspection.

During the inspection period, your conduct of activities at the Crystal River facility was generally characterized by safety conscious operations.

Within the scope of the inspection, no cited violations or deviations were identified.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

/RA/

Leonard D. Wert, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket No. 50-302
License No. DPR-72

Enclosure: NRC Inspection Report 50-302/99-09

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-302
License No:	DPR-72
Report No:	50-302/99-09
Licensee:	Florida Power Corporation
Facility:	Crystal River 3 Nuclear Station
Location:	15760 West Power Line Street Crystal River, FL 34428-6708
Dates:	December 26, 1999 through February 12, 2000
Inspectors:	S. Cahill, Senior Resident Inspector (Sections M1.2, E8.1) M. Franovich, Acting Senior Resident Inspector S. Sanchez, Resident Inspector
Approved by:	L. Wert, Chief, Projects Branch 3 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Crystal River 3 Nuclear Station
NRC Inspection Report 50-302/99-09

This seven-week period of resident inspection included aspects of licensee operations, engineering, maintenance, and plant support.

Operations

- Year 2000 preparations undertaken by the licensee for the rollover period were well implemented. No concerns or problems were noted. (Section O1.2)

- Maintenance rule requirements were adequately implemented following auxiliary feedwater pump FWP-7 inboard bearing failures. The two bearing failures were attributed to different causes. Corrective actions were reasonable to prevent recurrence (Section O2.1).

Maintenance

- The licensee performed a timely and methodical investigation of a heat-induced failure of the A emergency diesel generator radiator fan drive clutch. Slippage of the clutch at idle speed due to improper setting of clutch bushings caused the failure. Thorough corrective actions were developed to prevent recurrence (Section M1.2).

- ASME Section XI testing of raw water pump (RWP)-2A and RWP-3A was performed in accordance with the Code and Technical Specification requirements. Although the pumps were degraded, each pump remained operable and the technical justifications were consistent with the regulatory expectations of NUREG-1482, Guidelines for Inservice Testing at Nuclear Power Plants (Section M2.1).

Plant Support

- Operators responded appropriately to an actuation of a turbine lube oil deluge valve and spray down of some non-safety equipment. The spurious actuation was attributed to corrosion in the manual pull station circuitry. The licensee initiated a root cause team to review a recently identified declining trend in fire protection system reliability (Section F2.1).

Report Details

Summary of Plant Status

The plant began the inspection period at full rated thermal power and remained at that level until December 31, 1999, when power was lowered to 70 percent as a precautionary measure for the Year 2000 (Y2K) rollover period. On January 1, 2000, the unit was returned to 100 percent power and remained at that level for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 Routine Conduct of Operations Reviews (71707)

The inspectors routinely reviewed plant operations, including shift turnovers, operator narrative logs, temporary modifications and tagging indexes, and toured plant risk significant areas. The inspectors verified the alignment of selected, risk significant safety systems and verified implementation of Technical Specifications (TS) requirements. Noteworthy observations are discussed in subsequent paragraphs. The inspectors observed that operators demonstrated thorough control and awareness of plant evolutions. Control room operators consistently used three-way communication techniques, minimized distractions, and closely monitored the reactor controls. Shift turnover meetings were effectively conducted. Temporary modifications were appropriately tracked and controlled.

O1.2 Year 2000 Transition

a. Inspection Scope (71707)

The inspectors observed Y2K preparations the night of December 31, 1999. Previous Y2K programmatic reviews were documented in NRC Inspection Report 50-302/99-04. The inspectors reviewed the licensee’s preparedness activities associated with procedures for recovery of offsite power supplies, switchyard protection and vulnerabilities, emergency diesel operability, required actions for degraded grid conditions, and plant staffing.

b. Observations and Findings

At approximately 8:00 p.m. on December 31, 1999, the licensee commenced a power reduction from 100 to 70 percent power as part of the Y2K preparations. The inspectors were present in the control room during the rollover period, observed portions of the activities, and monitored key plant system parameters. No safety-related equipment was out of service nor were any risk significant maintenance activities ongoing during the periods before and after the rollover time. Part of the licensee’s contingency plan was to start and load the A-train emergency diesel generator (EDG); however, the licensee elected not to start and load the EDG because no significant Y2K-related problems were observed or reported from European communities. The inspectors noted a significant number of extra personnel were onsite and available should any problems arise. At approximately 4:00 a.m. on January 1, 2000, the licensee began a power increase. The unit was returned to 100 percent power at approximately 6:30 a.m. with no operational problems noted.

c. Conclusions

The Y2K preparations undertaken by the licensee for the rollover period were well implemented. No concerns or problems were noted.

O2 Operational Status of Facilities and Equipment

O2.1 Auxiliary Feedwater Pump 7 (FWP-7) Bearing Failure

a. Inspection Scope (62707, 71707, 37551)

The inspectors reviewed the facts and circumstances of a recent FWP-7 bearing failure. Pump vendor information, surveillance procedures (SP), corrective actions, and 10 CFR 50.65 maintenance rule (MR) issues were also evaluated. This failure and previous issues were discussed with the cognizant component and system engineers.

b. Observations and Findings

In the late 1980s, non-safety related FWP-7 was installed to reduce the reliance on extended high pressure injection/pilot operated relief valve cooling in a loss of all main feedwater and emergency feedwater. According to precursor card (PC) 3-C98-5385, removal of FWP-7 from service would increase the probability of core damage by a factor of 3.8. During the October 1999 refueling outage, the licensee installed a safety-related diesel driven emergency feedwater pump (EFP-3) which has reduced the risk significance of FWP-7 to some degree. The licensee continues to consider FWP-7 a MR risk-significant system. The unavailability criterion for FWP-7 was increased from 1.39 percent to 1.89 percent.

On December 4, 1998, the FWP-7 pump inboard bearing failed. The licensee performed an apparent cause evaluation. Cognizant component engineers informed the inspectors that this failure was attributed to a malfunctioning oiler system which resulted in insufficient bearing lubrication. The oiler was missing a center support. The oiler was repaired and an extent of condition review indicated that oilers for other station pumps were operating properly. FWP-7 was placed on the MR a(1) list for increased monitoring due to the functional failure. The system was monitored for approximately a year and returned to MR a(2) status (January 2000) after having completed approximately twelve successful surveillances. These surveillances did not indicate an adverse trend on pump vibration or bearing temperatures. The inspectors determined that a reasonable period of time had elapsed for increased system monitoring and sufficient surveillance tests were performed to permit a return to MR a(2) status.

On January 26, 2000, the FWP-7 pump inboard bearing failed again following a monthly surveillance test. Station personnel decided to repair the bearing the following week because the licensee’s equipment out-of-service risk software indicated that a normal green condition existed with FWP-7 out of service, the functional failure would return the system to MR a(1) status, and this was a non TS system. Station management indicated that when the decision was made to defer pump repairs until the following week, it was recognized that the MR unavailability performance criterion for FWP-7 would be exceeded. It was noted that the unavailability criterion for the emergency feedwater function would not approach a limit. At the time, the licensee believed that the FWP-7 unavailability criterion was overly restrictive and did not accurately reflect the plant risk reduction achieved by the recent addition of EFP-3. The licensee also determined that the additional unavailability time for FWP-7 had a negligible impact on the estimated annual core damage frequency. In addition, all three trains of emergency feedwater remained operable until FWP-7 repairs were completed. Following the FWP-7 repairs, the licensee's was considering revision of the FWP-7 unavailability criterion.

This second failure was also attributed to insufficient bearing lubrication; however, the problem this time was due to insufficient oil being maintained in the oil reservoir. The inspectors reviewed the as found conditions which revealed that the inner diameter of the slinger ring was dry and the level on the sight-glass was slightly below the center of the sight glass. In the past, oil level was maintained at the center of the sight-glass in accordance with the stamped oil level marking on the casing. Immediate corrective actions established that the proper oil level should be slightly above the sight glass center. This was based upon review of a vendor drawing for setup of the oiler system which indicated that the oil level should be set approximately 3.5 inches below the centerline of the shaft. Although not noted on the vendor drawing, oil level on the sight-glass should therefore be maintained approximately 1/16 inch above the actual oil level stamping on the pump casing. The licensee's extent of condition review and the inspectors' independent review did not identify any similar concerns with other risk-significant horizontal pumps. Inspectors observed that a new target level was clearly marked on the sight-glass for both inboard and outboard pump bearings for FWP-7, and operator guidance was provided in the control room as required reading. The inspectors determined that these corrective actions were reasonable to prevent recurrence.

The system engineer informed the inspectors that the system will be returned to MR a(1) status because of the functional failure. MR a(1) performance and monitoring goals were also under review for FWP-7. Through past surveillance tests and pump data, the inspectors determined that FWP-7 would have performed its intended functions before the failure was identified. No violations of regulatory requirements were identified.

c. Conclusions

Maintenance rule requirements were adequately implemented following auxiliary feedwater pump FWP-7 inboard bearing failures. The two bearing failures were attributed to different causes. Corrective actions were reasonable to prevent recurrence.

O8 Miscellaneous Operations Issues (92901, 90712)

O8.1 (Closed) Licensee Event Report (LER) 50-302/99-06-00: Procedure Revision Causes Improved Technical Specification (ITS) Surveillance Requirements to (Not) Be Implemented. On May 20, 1999, SP-301, Shutdown Daily Surveillance Log, was canceled and its requirements were incorporated into SP-300, Operating Daily Surveillance Log. During that procedure revision, the frequency for verifying high pressure injection (HPI) deactivation was changed from once per shift to once per day for some of the power sources. ITS Surveillance Requirements (SR) 3.4.11.1 and 3.4.11.2 were not completely met at the required frequency (once per shift) for the time frames of 1:30 a.m. on October 2, 1999, to 8:00 a.m. on October 5, 1999, and from 9:45 p.m. on November 2, 1999, to November 5, 1999. The SRs were performed properly for a portion of HPI and the remainder was verified every 24 hours. HPI was deactivated and tagged out of service during the times of the missed surveillances. At no time during the periods in question was there an actual vulnerability to exceeding pressure or temperature limitations. The root cause was personnel error during the procedure revision and review process when the information from SP-301 was incorporated into SP-300. This licensee-identified issue constitutes a violation of minor significance and is not subject to formal enforcement action.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance and Surveillance Testing Activities (61726, 62707)

The inspectors observed all or portions of the following work requests (WR) and surveillances and reviewed associated documentation. The following activities were included:

- SP-349C, Emergency Feedwater Pump EFP-3 and Valve Surveillance
- MP-610, Maintenance of Reheat Stop and Interceptor Valves
- WR-364581, Furmanite Installation on Reheat Valve RHV-7

The inspectors concluded that maintenance activities were performed methodically and in accordance with procedures. All work observed was performed with the work packages present and in active use. Pre-job planning was thorough and in sufficient detail to prepare the technicians for the assigned tasks. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure.

M1.2 <u>Failure of A Emergency Diesel Generator (EDG) Radiator Fan Driveshaft Clutch</u>

a. <u>Inspection Scope (62707, 61726)</u>

Following a successful normal monthly surveillance run of the A EDG on January 5, 2000, an operator discovered significant heat damage to the clutch connecting the EDG power takeoff shaft and the radiator fan drive shaft. The licensee declared the EDG inoperable based on the observed damage and initiated a root cause investigation. The inspectors observed the failed components and reviewed the investigation results.

b. <u>Observations and Findings</u>

The inspectors observed that sufficient heat had been generated in the clutch to discolor the protective housing, causing portions of the clutch shoe aluminum base metal to detach along outer edges and damage to the rubber shoe-to-hub bushings. The bushings establish the resistance of the clutch shoe to drum engagement, therefore determining the initial clutch engagement speed and slippage before full engagement. The licensee determined the clutch was fully engaged during the two-hour loaded surveillance run despite the damage and focused their investigation on slippage during initial startup. The inspectors verified the licensee methodically gathered available evidence and eliminated other causes such as vibration and overload.

Both A and B EDG clutch shoe material and engagement speed designs were modified during the October 1999 refueling outage, after which each clutch had its bushings set and tested. Difficulty was encountered setting and burnishing the A EDG clutch in that it did not fully engage until approximately 700 rpm. EDG idle speed is 500 rpm and rated speed is 900 rpm. The B EDG clutch set-up had required fewer iterations and it was fully engaged prior to 500 rpm. During previous upgrades to the EDG radiators in 1997 the licensee had requested guidance from the EDG vendor on allowable slippage and engagement speed. A specific full engagement speed acceptance criteria had not been developed and some slippage was considered acceptable by the EDG vendor. Therefore, with clutch vendor concurrence, the licensee accepted the A EDG set-up with slippage up to 700 rpm. The licensee’s investigation determined that the failure of the clutch was due to this slippage and consequent heat damage from running the EDG at idle speed as part of a normal slow EDG start process. Their root cause attributed the slippage to improper setting of the bushings and noted contributing causes of time pressure and incomplete evaluation of the differing October 1999 EDG clutch set-up results. Some information indicates that the EDG could have performed its safety function on an emergency start. The licensee determined that the B EDG was not susceptible to a similar failure since the EDG did not slip at the 500 rpm idle speed. The licensee and inspectors also performed non-intrusive visual inspections of the B EDG clutch to confirm no damage existed.

The inspectors determined the licensee investigation was thorough and the conclusion was supported by the physical evidence. Appropriate short term corrective actions were implemented including procedurally limiting time at idle speed and additional operator guidance material provided in the control room. Comprehensive long term corrective actions were developed. The inspectors witnessed the clutch repairs and set-up that were completed with vendor assistance. Clutch performance was consistent and the clutch did not slip above 500 rpm after burnishment. This further supported the conclusion that the failed clutch was improperly set, causing slippage up to 700 rpm.

c. Conclusions

The licensee performed a timely and methodical investigation of a heat-induced failure of the A emergency diesel generator radiator fan drive clutch. Slippage of the clutch at idle speed due to improper setting of clutch bushings caused the failure. Thorough corrective actions were developed to prevent recurrence.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Indicated Degradation in RWP-2A and RWP-3A During ASME Section XI Testing

a. Inspection Scope (61726, 62707)

The inspectors evaluated inservice testing of raw water pumps (RWP)-2A and RWP-3A to determine the effectiveness of the licensee's American Society of Mechanical Engineers (ASME) Section XI testing program. The inspectors evaluated compliance with ASME code requirements, reviewed test methods, acceptance criteria, test instrument range/accuracy, and compliance with Technical Specification requirements. The inspectors also verified that corrective actions were taken as applicable and operability evaluations were properly performed and consistent with regulatory guidance provided in NUREG-1482, Guidelines for Inservice Testing at Nuclear Power Plants.

b. Observations and Findings

On February 8, 2000, the inspectors observed portions of SP-340A, RWP-3A, DCP-1A and Valve Surveillance. RWP-3A circulates seawater to the decay heat closed cycle cooling (DC) heat exchanger (DCHE)-1A. During the test, the procedure-specified range of 10,000 to 10,200 gallons per minute (GPM) flow for RWP-3A was not attained due to unknown reasons. The inspectors observed erratic readings on the flow indicators ranging between 9,500 and 10,000 gpm. The procedurally-specified flow range is necessary to obtain comparable, trendable test data for pump vibrations and differential pressure. Maximum flow achieved was approximately 9,750 gpm. The test was terminated due to the low flow conditions. The licensee subsequently determined that the system was still operable since the minimum required design flow was 9,700 gpm per the enhanced design basis documents.

The licensee proceeded to troubleshoot the low flow conditions and decided to pursue tube cleaning of DCHE-1A. The inspectors observed portions of the cleaning and system restoration. Maintenance personnel removed a handful of seawater-related debris from the heat exchanger, which was not a sufficient amount of debris to affect system performance. Maintenance personnel were thorough in their visual inspection of the inlet and outlet pipes as well as the tubes themselves to remove all foreign material with appropriate quality control verification. The inspectors observed strong maintenance supervisor oversight of the work activities.

However, the inspectors determined that DCHE-1A unnecessarily accrued some additional unavailability time. DCHE-1A was opened for cleaning and unavailable for approximately 12 hours. During the cleaning, the inspectors questioned maintenance personnel if the instrumentation or flow indicators used to perform the surveillance had been eliminated as a possible source for the indicated low flow conditions. A recheck of the test instrumentation and indicators was not done prior to the DCHE-1A being removed from service. DCHE-1A was pursued for cleaning based on previous history of clogging; however, the current environmental conditions did not support potential clogging of the tubes. A subsequent retest produced similar flow conditions. Following the retest, the flow indicators were bench tested. The indicated flow was approximately 300 gpm below the simulated test signal of 10,000 gpm. At the end of the inspection period, engineering prudently considered that the pump was still degraded until the next scheduled test is performed. The inspector noted that according to the 1999 fourth quarter system health report, the raw water (RW) system was in MR a(1) status, in part, because the B train of RW-to-DC had exceeded its unavailability criterion of 1.28 percent. The A train unavailability was at 0.76 percent with a criterion of 1.28 percent.

On February 9, 2000, a surveillance test of RWP-2A indicated that the pump was in the required action range on low differential pressure across the pump. RWP-2A supplies seawater to the service water heat exchangers during emergency modes of operation. During troubleshooting, flow and pressure instrumentation were eliminated early as a potential sources of the problem. On February 9, 2000, divers inspected raw water pit A, each RWP's suction bells, and the pumps' impellers. No significant marine growth or other foreign material was observed and no obvious degradation of the impellers was noted. A retest of the pump indicated alert levels for low differential pressure. The inspectors determined that the engineering analysis under CP-102, Inservice Test (IST) Pump and Valve Data Review, was consistent with the guidelines of NUREG-1482, which permits use of engineering analysis to defer repairs, provided no significant additional degradation would occur until repairs or pump replacement could be performed. The licensee's analysis provided sufficient basis to support continued operability given the rate of degradation and design margins for flow.

c. Conclusions

ASME Section XI testing of RWP-2A and RWP-3A was performed in accordance with the Code and TS requirements. Although the pumps were degraded, each pump remained operable and the technical justifications were consistent with the regulatory expectations of NUREG-1482.

III. Engineering

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 50-302/98-11-00: Control Complex Chillers Operated Outside Design Basis. This LER involved the potential inability of the control complex chillers to start with extremely elevated service water cooling temperatures that could occur during a design basis event. The chiller issue was previously discussed in LER 50-302/97-25-00, but had been separated from several other similar concerns with ultimate heat sink (UHS) temperature calculations and addressed in LER 50-302/98-11-00. Inspection Report 50-302/98-11 closed LER 50-302/97-25-00 when the other UHS issues were resolved through plant modifications and revised calculations. Changes to chiller operating procedures and UHS calculations added margin to the control complex chiller issue, but did not fully resolve it. The issue remains open in the licensee's corrective action system under precursor card (PC) 97-8080. The PC contains appropriate compensatory actions to declare the UHS inoperable and enter the associated Technical Specification at a reduced limit of 94.1 degrees Fahrenheit (F) inlet temperature versus the normal limit of 95 degrees F. UHS temperature has never exceeded 94 degrees in the operating history of the plant. The licensee also has a docketed commitment to resolve this restriction by the end of their next refueling outage in the fall of 2001. Preliminary plans are to replace the control complex chillers with an improved design that will start at elevated temperatures. All of the UHS issues in both LER 50-302/97-25 and LER 50-302/98-11 were identified during extent of condition reviews for NRC Enforcement Action 96-365, Violation B (02013), which was originally issued for errors in changing the design basis upper limit for the UHS. Since the UHS issues had existed prior to the enforcement action, no further enforcement action is required. Appropriate short term and long term actions for this issue were addressed in the corrective action system. LER 50-302/98-11 is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Comments (71750)

The inspectors made frequent tours of the controlled access area and reviewed radiological postings. The inspectors observed that workers were adhering to the requirements for wearing protective clothing. The inspectors also determined that locked high radiation doors were properly controlled, high radiation and contamination areas were properly posted, and radiological survey maps were updated to accurately reflect radiological conditions in the respective areas.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Actuation of FSV-10 Deluge Valve and Overall Fire Protection System Reliability

a. Inspection Scope (71750, 37551)

The inspectors reviewed the circumstances of an actuation of the fire protection deluge system for the turbine lube oil system. Inspectors walked down affected portions of the fire protection system and plant equipment. The inspectors also evaluated operators' response to the event, immediate corrective actions, and additional information on overall fire protection system reliability.

b. Observations and Findings

On January 24, 2000, fire service valve (FSV)-10 spuriously actuated, which automatically started fire service pump No. 1 on low system pressure. FSV-10 is a deluge valve for suppressing fires in the turbine lube oil system area of the turbine building. The valve opened and sprayed water on the lube oil tank, several turbine building pumps, and several lube oil pumps. Numerous annunciators alarmed on the fire service panel located in the control room. Operators immediately responded and de-energized electrical equipment in the area, verified no actual fire was present and manually isolated FSV-10 by closing FSV-108. No plant transients occurred and no evidence of heat or fire was present to set off the heat detectors. The inspectors determined that operators responded appropriately and promptly to the event.

After systematic troubleshooting, Maintenance determined that the most likely source of the actuation was due to corrosion in the associated manual pull station circuitry. Several other components were also replaced including a detector, relays and relay bases. The deluge valve was returned to service after the end of the inspection period with no additional problems reported.

The inspectors noted that numerous precursor cards and work requests were written against the fire protection system (e.g., fire doors, detectors, CARDOX equipment) within the last year which is indicative of declining system health. The licensee has also recognized a growing pattern of precursor cards written against the system. A root cause team was formed to address the issues. The inspectors observed portions of the root cause team meeting and noted that the multi-disciplined team was well represented by Operations, Maintenance, and Engineering, with individuals possessing significant plant experience with these issues and/or root cause analysis. The team appropriately focused on establishing the scope of the issues, the frequency of nuisance alarms, the impact to plant operators, aging of the detection system, fire protection system equipment failures, and identifying potential procedural improvements for surveillance and maintenance activities.

c. Conclusions

Operators responded appropriately to an actuation of a turbine lube oil deluge valve and spray down of some non-safety equipment. The spurious actuation was attributed to corrosion in the manual pull station circuitry. The licensee initiated a root cause team to review a recently identified declining trend in fire protection system reliability.

V. Management Meetings

X1 Exit Meeting Summary

The inspection scope and findings were summarized on February 16, 2000. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

PARTIAL LIST OF PERSONS CONTACTED

Licensees

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J. Cowan, Vice President, Nuclear Operations
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R. Grazio, Director, Nuclear Site and Business Support
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J. Holden, Vice President and Director, Site Nuclear Operations
C. Pardee, Director, Nuclear Plant Operations
D. Roderick, Director, Nuclear Engineering & Projects
T. Taylor, Director, Nuclear Operations Training

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Conduct of Maintenance
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Followup - Operations
IP 92903:	Followup - Engineering

ITEMS CLOSED

50-302/99-06-00	LER	Procedure Revision Causes ITS Surveillance Requirements to be Implemented Improperly. (Section O8.1)
50-302/98-11-00	LER	Control Complex Chillers Operated Outside Design Basis. (Section E8.1)