UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-335/92-10 and 50-389/92-10

Licensee: Florida Power & Light Co.
9250 West Flagler Street
Miami, FL 33102

Docket Nos.: 50-335 and 50-389 License Nos.: DPR-67 and NPF-16

Facility Name: St. Lucie 1 and 2

Inspection Conducted: May 3 - June 8, 1992

Inspectors: for S. A. Elrod, Senior Resident Inspector — 7/7/92 Date Signed

for M. A. Scott, Resident Inspector — 7/7/92 Date Signed

Approved by: K. D. Landis — 7/7/92 Date Signed
K. D. Landis, Section Chief
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, and Unit 2 outage activities. Backshift inspections were performed on May 3, 6, 7, 8, 10, 11, 12, 13, 17, 18, 19, 22, and 25; and on June 2, 3, 6, and 7.

Results:

The licensee's approach to refueling Unit 2 was excellent. The use of a submarine with a television camera to inspect major components as they were lifted helped preclude inadvertent damage. Root cause evaluations for conditions adverse to quality were excellent. Unit 1 operations were quiet and uneventful.

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REPORT DETAILS

1. Persons Contacted

Licensee Employees

* * D. Sager, St. Lucie Plant Vice President
* * G. Boissy, Plant General Manager
* J. Barrow, Fire/Safety Coordinator
* H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Manager
* R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Manager
* * J. Dyer, Quality Control Supervisor
* * R. Englmeier, Nuclear Assurance Manager
* R. Frechette, Chemistry Supervisor
* * J. Holt, Plant Licensing Engineer
* * C. Leppla, Instrument and Control Supervisor
* * L. McLaughlin, Licensing Manager
* G. Madden, Plant Licensing Engineer
* A. Menocal, Mechanical Supervisor
* T. Roberts, Site Engineering Manager
* L. Rogers, Electrical Supervisor
* N. Roos, Services Manager
* C. Scott, Outage Manager
* D. West, Technical Manager
* J. West, Operations Supervisor
* W. White, Security Supervisor
* D. Wolf, Site Engineering Supervisor
* * E. Wunderlich, Reactor Engineering Supervisor

Other licensee employees contacted included engineers, technicians, operators, mechanics, security force members, and office personnel.

NRC Personnel

* * S. Elrod, Senior Resident Inspector
* * M. Scott, Resident Inspector

* Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Plant Status and Activities

Unit 1 began and ended the inspection period at power. The unit ended the inspection period in day 168 of power operation since its return from outage. Aside from a down power to clean 2 of 4 condenser water boxes, plant operations were uneventful.

Unit 2 began the inspection period in a maintenance and refueling outage that commenced on April 20. At the end of the inspection, Unit 2 was on a schedule to complete the outage about June 19, 1992.

On May 4 - 8 and May 15 - 22, an NRC inspection was conducted in the area of Inservice Inspection. The results of this inspection were documented in NRC Inspection Report 50-335,389/92-09.

On May 18 - 22, an NRC inspection was conducted in the area of radiation protection. The results of this inspection were documented in NRC Inspection Report 50-335,389/92-12.

3. Review of Plant Operations (71707)

a. Plant Tours

The inspectors periodically conducted plant tours to verify that monitoring equipment was recording as required, equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspectors also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material was stored properly, and combustible materials and debris were disposed of expeditiously. During tours, the inspectors looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts. The frequency of plant tours and control room visits by site management was noted to be adequate.

The inspectors routinely conducted partial walkdowns of ESF, ECCS, and support systems. Valve, breaker, and switch lineups as well as equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system and area walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

- Unit 2 SITs,
- Unit 2 2A CCW Heat Exchanger,
- Unit 2 2A AFW pump, and
- Unit 2 2A battery.

b. Plant Operations Review

The inspectors periodically reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs, and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to assure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

During this inspection period, the inspectors reviewed the following tagouts (clearances):

- 1-5-54 Unit 1 1A startup transformer, and

- 2-5-187 Unit 2 2A safety-related battery.

Four days prior to shutdown for the Unit 2 outage, the "2A" train hot leg injection check valve V3525 began to have bypass leakage indication. Occasionally, hot leg check valves closest to the RCS have leaked. The "2B" train hot leg check valve bypass leakage alarm had been annunciated in the control room for about seven months (IR 91-21). In each train, two other check valves in line with the subject valves provided backup boundaries between the RCS and the ECCS. The repair activities related to these three-inch valves are discussed in section 4.a of this report.

On April 20, 1992, Unit 2 began a shutdown for refueling. At approximately 15 percent power, an expected difficulty in maintaining the core flux profile caused the operators to manually trip the reactor in lieu of continuing a gradual power reduction. By design, a reactor trip causes a turbine trip. This time, the turbine did not actually shut down from either automatic or remote manual trip signals and had to be manually tripped at the turbine standard. No equipment damage occurred from the turbine failing to trip because of the low power level and no subsequent challenges to reactor safety systems occurred.

The licensee established a root cause team and performed an extensive investigation of the turbine trip circuits and components - including dissection of trip valves. The results of these ongoing investigations will be discussed in IR 389/92-11, the next resident inspection report.

Early in the main turbine overhaul, the licensee discovered LP turbine blading cracks. This resulted in repair attempts and subsequent replacement of both LP turbine rotors with used spares that still had some allowed operating time remaining. Resolution of this issue was still under evaluation during this inspection period and will be discussed in IR 389/92-11, the next resident inspection report.

An inspector witnessed the Unit 2 reactor vessel head lift on May 4 and the subsequent UGS lift and removal from the reactor vessel on May 8. These movements were in accordance with procedure 2-M-036, Rev 13, Reactor Vessel Maintenance - Sequence of Operation. Pre-job briefings were complete and well attended. Coordination between interfacing groups went well. Pre-evolution preparations were thorough. Both evolutions ran smoothly.

During the course of the UGS lift, the licensee utilized a robot submarine in the water-filled refueling cavity. The robot carried an underwater camera that was utilized to ensure that the UGS had been lifted clear of the reactor vessel flange prior to moving the UGS horizontally to its temporary stowage position. This particular observation precluded damage to the vessel and vessel-to-refueling-cavity seal (re: IN 92-25, Potential Weakness in Licensee Procedures for a Loss of the Refueling Cavity Water). Additionally, the robot camera observation clearly demonstrated that no fuel bundles or CEAs were suspended from the UGS prior to the completion of the lift out of the vessel. Should an item have been found suspended from the UGS at this early stage, prior to losing alignment with the fuel assemblies remaining in the reactor vessel, the UGS could be reset with no expected component damage. The robot camera acuity and refueling water clarity were excellent, allowing the robot to be readily used not only for the above purposes, but also for subsequent reactor vessel flange inspections.

On May 6, the pre-UGS-lift containment isolation test was performed per procedure OP 2-1600023, Rev 21, Refueling Sequence Guidelines. All equipment operated as planned, isolating the containment and starting the available EDG. Prior to the test, personnel in containment were notified and air-supplied work which would lose air during the test was temporarily suspended.

On May 16, a licensee electrician found the 2C CCW pump emergency load sequence relay set at 18.14 seconds in lieu of the TS-required 6 seconds plus-or-minus (+/-) one second. The 2AB 4160 V bus serving the 2C CCW pump was out of service at the time and the electrician was performing a routine check of selected emergency load sequence relays. The relays are located inside of the pump circuit breaker cubicles. The relay time settings are made using numbered thumb wheels on the relay faces. This pump had recently operated with the correct time delay during the integrated safeguards test performed on April 21, shortly after plant shutdown, Records indicated that the relays last "as left" setting was 6.04 seconds at the 1990 outage surveillance.

The licensee determined that a construction services journeyman electrician had inadvertently moved the thumbwheel during circuit breaker cubicle cleaning. The licensee inspected the remainder of the Unit 2 safety-related breaker relays and found no other relay settings changed. No LER was generated based on the satisfactory safeguards test and the plant mode.

During the discovery phase and troubleshooting of the Unit 2 relays, and prior to the licensee finalizing their followup actions, an independent group discovered a similar Unit 1 problem. On May 21, during a Unit 1 walkdown, an engineer found the 1A CCW pump emergency load sequence relay thumbwheel set differently than expected. This relay setting was 7.01 seconds in lieu of the required 6 +/- 1 seconds. Unit 1 was operating at 100 percent power. The remainder of the Unit 1 load sequencing relays were inspected and the following was discovered:

pump type	As-found dial setting	As-timed test time%	Safeguards test time*	TS required time
1A CCW	7.01	7.17sec.	6.18sec.	6 +/-1 sec.
1B CS	12.98	13.11	12.16	12 +/-1
1B ICW	8.08	8.29	8.256	9 +/-1

% surveillance performed on May 21
* tested during safeguards test in December 1991

The above indicates that both the 1A CCW and the 1B CS pump relays were found outside of TS 4.8.1.1.2.e.11 required values. The 1B ICW pump relay setting had been changed slightly but was within specification. The licensee has corrected the relay settings noted above, counseled the contractor, changed the bus cleaning inspections, and was preparing an LER on the Unit 1 problem. At the end of the inspection period, the licensee was considering additional relay setting checks prior to Unit 2 entering Mode four.

On June 7, with Unit 2 in Mode 5 and one operable EDG required, both the 2A and 2B EDGs were operable when licensee personnel inadvertently wetted down the 2B EDG with a water hose. The 2B EDG room had some areas that required cosmetic cleaning. Maintenance helpers, without specific guidance, used a potable water hose to wash down the inside of the room. Operators discovered this when they received an electrical ground fault alarm in the control room. The operators declared the 2B EDG inoperable, cleaned and dried the affected EDG components, and returned the 2B EDG to operability. This event will be further discussed in IR 335,389/92-11.

c. Technical Specification Compliance

Licensee compliance with selected TS LCOs was verified. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, and switch positions, and by review of completed logs and records. Instrumentation and recorder traces were observed for abnormalities. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened. The inspectors verified that related plant procedures in use were adequate, complete, and included the most recent revisions.

d. Physical Protection

The inspectors verified by observation during routine activities that security program plans were being implemented as evidenced by: proper display of picture badges; searching of packages and personnel at the plant entrance; and vital area portals being locked and alarmed.

Aside from the main turbine fail-to-trip problem and the inadvertent wetting of 2B EDG discussed above, operational controls or actions were excellent. Recovery actions from the above events were appropriate and also controlled.

4. Surveillance Observations (61726)

Various plant operations were verified to comply with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, RWT conditions, containment pressure, control room ventilation, and AC and DC electrical sources. The inspectors verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, LCOs were met, removal and restoration of the affected components were accomplished properly, test results met requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel. The following surveillance tests were observed:

a. OP 1-2200050A, Rev 0, 1A Emergency Diesel Generator Periodic Test and General Operating Instructions;

b. OP 2-0640020, Rev 19, Intake Cooling Water System Operation [2C pump];

c. OP 1-2200050B, Rev 0, 1B Emergency Diesel Generator Periodic Test and General Operating Instructions;

d. OP 2-0410026, Rev 3, Differential Pressure Testing of Motor Operated Valves (Appendix "F" - CVCS Valves); and

e. LOI 2-LOI-0-54, Rev 0, Station Blackout Intertie Phase Testing.

The above activities were carried out in a professional manner.

5. Maintenance Observation (62703)

Station maintenance activities involving selected safety-related systems and components were observed or reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review: LCOs were met; activities were accomplished using approved procedures; functional tests and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; and radiological controls were implemented as required. Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

a. NPWO 4358/62, Hot Leg Injection Valve Inspection (discussed in paragraph 2 and in "outage" below);

b. NPWO 8596/66, Calibration Check of Installed Equipment Meters (MP 0990060, Rev 6);

c. NPWO 8356/66, Repair of "A" Train MFIVs;

d. NPWO 9001/66 and 8842/66, Repair and Testing of Unit 2 ADV MV 08-19A (EMP 0950064, Rev 0);

e. NPWO 4358/62, Unit 2 Reactor Vessel Head Stud Tensioning;

f. NPWO 8388/66, Unit 2 2A AFW Pump Motor Lead Repair;

g. NPWO 4959/66, Replace 2B Safety-Related Battery Cells; and

h. NPWO 8328/66, Safety-Related 2A Battery 18 Month Surveillance (MP 2-0960150, Rev 3).

NPWOs 4959 and 8328 above dealt with maintenance and testing of the Unit 2 safety-related batteries. During the course of preventive maintenance, the electricians noted a disfiguration on some of the battery cells, located on the surface of the lead berm surrounding the connection posts. The disfiguration on the battery cells has, to date, been described by the battery vendor as "nodular corrosion." This berm, not a part of the battery post, seals the jar lid (battery cell top) and keeps its contents from "wicking" up the battery post.

Although there has been no evidence of capacity loss or other testable battery cell degradation, the licensee replaced 15 cells on the 2A battery and 11 cells on the 2B battery (each contains 60 cells). These cells had exhibited various levels of the external manifestation of this corrosion. The licensee did not want even the perception of battery problems. At this site, the corrosion appears to become obvious after about four to five years in service on the C&D cell model LCY-39. It appeared that the corrosion was occurring in the berm at the sealing point around the battery post of the cell jar with associated external manifestation and, for that reason, was not due to external activities such as improper maintenance. From physical evidence and monthly PM test data, the removed batteries did not appear to be jeopardized by the corrosion.

The battery vendor has been contacted for warranty information and guidance concerning possible corrective actions. On May 8, 1992, the licensee formally submitted a letter to the vendor addressing many issues. The licensee anticipates further coordinated action with the vendor, such as perhaps dissecting one cell with extensive corrosion.

The NRC inspectors scrutinized the batteries in Unit 1 safety-related applications. These had received maintenance during the Unit 1 outage in November - December, 1991. 1A Battery Cell number 10 and 1B Battery Cells number 8 and 37 exhibited the initial signs of nodular corrosion. Licensee persons stated that no manifestation had been noted during the previous outage maintenance of these Unit 1 batteries. The licensee's monthly PMs have shown no battery cell performance deterioration. The Unit 2 battery cells were installed in 1987 and the Unit 1 cells were installed in 1988.

A licensee evaluation of the Unit 1 battery cells with corrosion (documented in letter JPN-ST-92-152 dated June 12, 1992) stated that the corrosion posed no immediate operability threat. The affected cells were stated to be scheduled for replacement during the 1993 refueling outage. The inspectors will follow the battery phenomena as part of the routine inspection program.

6. Outage Activities (62703)

The inspector observed the following overhaul activity during the ongoing Unit 2 outage:

Approximately four days prior to Unit 2 shutdown, the 2A hot leg injection check valve began to leak to the point that a control room annunciator indicated a pressure buildup between the subject check valve and the next upstream check valve. Following reactor shutdown, the valve was opened and inspected per NPWO 4358/62 (cut and remove valve) to ascertain the cause.

Inspection findings indicated that the valve had severe pitting on both the seat and the disk. Initial speculation was that steam flashing had induced the pits. For steam to flash from the RCS, the piping upstream of the check valve would have to be partially voided. This scenario was being developed at the end of the inspection period.

QCR M92-734 (dated May 30) documented the cleanliness and another upstream piping problem. Tightly adherent brownish-black scale was found on the piping just upstream of the valve. This material was cleaned from the pipe and a portion of the material was sent to a laboratory for analysis (see letter to A. G. Menocal dated June 5, 1992, JPN/ESI/JB MET 92-180); no results had been returned at the end of the inspection period. Pitting was noted in the same piping upstream of the check valve. This pitting was evaluated by a licensee corporate metallurgist (letter to A. G. Menocal dated June 3, 1992, JPN/ESI/JB MET LAB 92-180) and was described as being due to steam erosion and the piping was deemed suitable for continued service. A portion of the piping had been removed during initial attempts at valve replacement. This pipe section was also taken to a laboratory for evaluation which was to occur subsequent to this inspection period.

Formal responses to QCR M92-734 on the scale and pitting were not initially issued. These written responses came after the NRC requested the information. To the licensee's credit, the pits had been discussed at length by several credible personnel (level III inspectors and metallurgists) and the pipe sample and scale material had been removed prior to the NRC request. The licensee had evaluated but not documented the salient points.

Due to the severe pitting in the hot leg valve, the licensee determined that repair in place was not feasible and that the valve had to be replaced. A freeze seal was set on May 26 and remained in place until June 8 when the new valve's root pass and first hot pass weld bead were

found acceptable by radiography. The welding of the valve was complicated by the valve's lack of accessibility, proximity of the freeze seal to one of the weld areas, and the lack of qualified welders that had made recent radiographically qualified welds. The licensee was very cautious with this class 1 piping weld.

Maintenance activities addressed above were well planned and controlled.

7. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, and ignition source/fire risk reduction efforts. Fire protection during outage activities was quite good.

8. Refueling activities (60710)

During the refueling, the inspectors observed fuel movement and related processes. Procedures in effect were:

- PCM 067-292E The Cycle 7 Fuel Reload;
- PREOP 3200090, Rev 1, Refueling Operation;
- OP 2-1630024, Rev 13, Refueling Machine Operation;
- OP 2-1600023, Rev 21, Refueling Sequencing Guidelines;
- OP 2-1600024, Rev 16, Filling and Draining the Refueling Canal;
- OP 2-1630021, Rev 4, New Fuel Elevator Operation;
- OP 2-1630022, Rev 11, Spent Fuel Handling Machine Operation; and
- OP 2-1630023, Rev 5, Fuel Transfer System Operation.

The operators observed/involved with the process of transferring fuel into and out of the containment were knowledgeable of the various machine operations and the details of the fuel movement process, and could rely on the available support staff such as reactor engineering. Throughout the fueling effort, the support contractor for the refueling and spent fuel machines was available in case a problem arose.

During fuel movement on May 10, 1992, a problem arose involving the incore refueling machine. The refueling machine operator had grappled fuel bundle G10 preparing to make a lift from a filled area of the core. Normally the grappled fuel is pulled up into the hoist box and then the two main parts are simultaneously pulled up into the refueling machine (telescoping) mast. In this instance, the spreader, which is attached to the end of the hoist box, snagged the fuel bundle and, with the bundle supporting the hoist box, they were lifted simultaneously to the mast. Before the bundle was completely removed from the core, the operator noted the out-of-sequence weight increase (normally the weight of the fuel alone and then the combined fuel and hoist box weight, but in this instance it was the combined weight of the fuel and box at the start of the lift) and stopped the lift. The bundle, which was then held with just inches of its length remaining in the core, was returned to its fully installed position and an investigation begun. No actual fuel damage occurred.

This event was investigated by the licensee as follows: reason for the lift problem, physical condition of the affected bundle and adjacent bundles, and operational lessons to be learned. The primary reasons for the handling problem are discussed below:

- One of the primary reasons for the problem was the operator missed the fact that the digital readout on the refueling machine indicated the weight greater than one fuel bundle (1460 lbs). With the initial withdrawal of the bundle, the observed weight should have only been the fuel itself. Instead, the digital readout indicated the weight of hoist box with the fuel bundle (approximately 2500 lbs).

- Additionally, a refueling machine lift interlock, the fuel only overload module CR-D3, failed such that it did not halt the lift with the combined hoist box and fuel bundle weight. Had the interlock functioned, the operator would not have been able to lift the combined weight of the bundle and box. Prior to the refueling, this function had been tested with a test weight.

- Further, for the spreader, which is an extension of the hoist box, to snag the bundle at its upper end (flow plate), the spreader had to be misaligned with respect to the bundle such that the spreader wrongly rested on top of the bundle flow plate. The misalignment was probably due to normal bowing and twisting of the used fuel bundles and clearance between the grapple and the end of the hoist box.

The licensee made inspections of the refueling machine and researched available data. The procedural fuel location and the operator recorded hoist box/grapple position indicated a few thousandths of an inch difference in hoist box to bundle alignment (X and Y refueling machine position relative to fuel location in the core). The refueling machine mast was in its proper rotational orientation. The refueling machine alignment to existing benchmarks was within tolerance.

Fuel bundles tend to twist and bend when irradiated in the core. Fuel typically lasts through three fuel cycles or reloads. To reduce the geometry changes and allow even fuel burnup, the fuel is moved and turned in the core. Even with this effort, Unit 2 fuel has been observed with bowing of approximately 3/8 of an inch. This change in geometry is probably the major contributor to hoist box misalignment with the fuel.

The fuel vendor did make inspections of all eight bundles surrounding bundle G10 and bundle G10 itself. G10 was removed to the SFP and examined there via remote camera. The tops of the surrounding bundles in the core were examined in place with a camera. No evidence of damage was determined (ABB/CE letter F2-92-052 of May 18, 1992, relates).

The corrective actions were completed for the G10 bundle problem. The overload module was replaced and tested prior to any further fuel movement. The refueling machine was operationally checked prior to any further fuel movement. Night orders were issued regarding attentiveness to grapple weight loading sequence.

Observed refueling activity was satisfactory.

9. Exit Interview (30703)

The inspection scope and findings were summarized on June 26, 1990, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

10. Abbreviations, Acronyms, and Initialisms

ABB	ASEA Brown Boveri (company)
AFW	Auxiliary Feedwater (system)
ATTN	Attention
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CS	Containment Spray (system)
CVCS	Chemical & Volume Control System
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EMP	Electrical Maintenance Procedure
ESF	Engineered Safety Feature
IR	[NRC] Inspection Report
JPN	(Juno Beach) Nuclear Engineering
lb	pound
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LOI	Letter of Instruction
LP	Low Pressure
MFIV	Main Feed Isolation Valve
MP	Maintenance Procedure
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PCM	Plant Change/Modification
PM	Preventive Maintenance
Preop	Pre Operational
QCR	Quality Control Report
RCS	Reactor Coolant System
Rev	Revision
RWT	Refueling Water Tank
SFP	Spent Fuel Pool
SIT	Safety Injection Tank
TS	Technical Specification(s)
UGS	Upper Guide Structure