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

Report Nos.: 50-335/91-17 AND 50-389/91-17

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: August 19 - September 16, 1991.

Inspectors: _____ 10/11/91
for S. A. Elrod, Senior Resident Inspector Date Signed

_____ 10/11/91
for M. A. Scott, Resident Inspector Date Signed

Approved by: _____ 10/11/91
K. D. Landis, Section Chief Date Signed
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 review of special reports.

Results:

Three areas of interest arose during the inspection period. Some accelerated corrosion was noted on safety-related small-bore carbon steel piping. The utility was evaluating this condition for further actions. The valve position indicator design of a Dragon Company vent valve created an unexpected leak that had been seen previously. The licensee was removing these indicators at inspection's end. Additionally, procedural and sealant cure problems were noted during main feed isolation valve work. The licensee took actions to clarify the preventive maintenance procedure and was performing actions to remedy sealant use problems.

In the areas inspected, violations or deviations were not identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Sager, St. Lucie Site Vice President
H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Superintendent
* R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Superintendent
* R. Englmeier, Site Quality Manager
* R. Frechette, Chemistry Supervisor
* J. Holt, Plant Licensing Engineer
* C. Leppla, I&C Supervisor
* L. McLaughlin, Plant Licensing Superintendent
* A. Menocal, Mechanical Maintenance Supervisor
* L. Rogers, Electrical Maintenance Supervisor
N. Roos, Services Manager
C. Scott, Outage Management Supervisor
* D. West, Technical Staff Supervisor
* J. West, Operations Supervisor
W. White, Security Supervisor
* D. Wolf, Site Engineering Supervisor
* G. Wood, Reliability and Support Supervisor
E. Wunderlich, Reactor Engineering Supervisor

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

NRC Employees

* 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. Review of Plant Operations (71707)

Unit 1 began and ended the inspection period at power - day 74 on line.

Unit 2 began and ended the inspection period at power - day 284 on line.

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 and equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

- Unit 1 EDGs,
- Unit 1 and 2 RWTs,
- Unit 1 ECCS pipe tunnel, and
- Unit 1 and 2 CSTs.

During a tour, the inspector noted that the Unit 1 cask crane leg concrete boots, which extended about six feet above ground, had cracks. Since the maintenance department was having the crane refurbished, this was pointed out to them for evaluation.

On August 22, the 1A waste monitor pump was squealing. The Unit 1 ANPS was notified.

During a tour, the inspector observed that abandoned supports and hangers in the Unit 1 letdown room, previously identified to the licensee, had been removed per NPWO 1437/61. The workmanship was good.

During a tour, inlet dampers D-25 for HVE 7A and D-26 for HVE 7B were observed to each have two grease fittings, one on each side of the damper. These had obviously not been greased for a very long time, having been painted several times. Vendor manual 8770-7119, Rev 0, Maintenance and Operating Instructions for P.O. 10543, required a six-month lubrication interval for dampers cycled 15 or less times a month. These dampers were rarely operated. Since these dampers were not in the preventive maintenance program, and to ensure others were

not missed, the licensee is comparing the total equipment database with the PM program in this area.

The suction boot for HVE 9B, ECCS room exhaust, was coming unglued. The licensee evaluated the condition and found that HVE 9B was operable as found but intends to address this suction boot during the upcoming outage.

A 1/2-inch-diameter carbon steel instrument pipe, located between the 1A AFW pump discharge flow orifice and root valve V 09111, developed a leak. Downstream of V 09111, the line changed to stainless steel tubing which was in turn connected to flow transmitter FT 09-2A. The entire line had been covered with lagging. A leak of about 5 milliliters per minute was discovered and NPWO 61/0392 initiated on August 4. Over the next several shifts the lagging was removed.

No specific, formal evaluation of the leakage or operability occurred at the time of failure. Since the instrument piping (which consisted of two nipples and a 90 degree elbow) did not require evaluation under ASME Code Section XI (Article IWB-1000). No other site/licensee procedures directed an evaluation either.

The affected instrument line was replaced under the above NPWO on August 13 prior to performing a scheduled 1A AFW pump surveillance.

At the request of the inspector, the failed piping was taken to the licensee's material lab for examination. Licensee laboratory report MET LAB 91-208 of August 27, 1991, concluded that the pipe corrosion was probably due to water that had been contaminated with chlorides and trapped under the lagging. The laboratory report further indicated that the external corrosion removed an outer layer of metal on the instrument line nipple/elbow, exposing a weld defect. The defect took the form of a porosity that provided a localized leak path between an elbow socket joint and the exterior of the weld. The licensee judged this defect to not be a catastrophic failure precursor.

Rain water or leakage trapped under lagging had been previously noted in other locations in the steam trestle area of both units. Most notably, in December, 1989, a 1-inch-diameter non-safety-related main steam line drain, MS-49, failed. Engineering report JPN-PSL-89-3829 showed the cause to be exterior corrosion under lagging and freeze damage.

In the past, the licensee had developed long term engineering evaluations on certain systems, such as the ICW and CCW, to cover known tendencies in system subcomponents. These evaluations have served the licensee numerous times over the years. Engineering was studying the carbon-steel-to-wetted-lagging corrosion phenomena in exterior applications and was considering developing a plan which may result in lagging modifications, piping inspections, and engineering

evaluations. At the end of the inspection period, the plant was generating an REA to fund engineering research already begun independently.

In response the emergent need for evaluating leakage that may potentially degrade a safety-related system, the licensee has changed existing procedure OP 0010129, Equipment Out of Service, to allow a method for evaluating potentially degraded systems or components. The licensee also issued a night order discussing the expectations and text of the change prior to distribution of the procedure revision.

While preparing for the MTC test on August 26, the Unit 1 control room operators received indication that an ECCS sump was unexpectedly filling and automatically pumping to the waste collection system. An SRO investigated, found the 1A RDT pump casing drain valve not completely shut, and closed the valve. Shortly before this discovery, the SNPO had closed the same valve when restoring system alignment following pump maintenance. The valve position indicator was loose and had jammed against the valve body, preventing the valve from closing completely.

IR 335,389/90-11, issued May 11, 1990, at the end of the last Unit 1 outage, discussed a leak involving another valve of the same type. This other valve was on the SDC system and leaked over 10 gpm during a plant cooldown. That minor leakage did not effect shutdown cooling capability but the valve was blowing steam in the pipe penetration room.

The valves were both manufactured by the Dragon company and were typically installed as vent and drain valves. Some were used as inline isolation valves. These Dragon valves were installed throughout both units' primary and ECCS piping. They had a valve position indicator that caused both problems. The indicator was a hollow metal cylinder closed on one end and threaded to match the valve stem. The indicator threaded onto the valve's stem and was lock nutted to the stem with the open end of the cylinder oriented toward the valve body. The distance between the indicator's open end and the valve body was used to indicate the valve's position. The indicator was initially adjusted to show the correct valve position, but the locking nut failed to permanently restrain the indicator on the stem. Thus the indicator could contact the valve body and jam the stem prior to complete manual closure.

This particular valve design was also susceptible to slight leakage after several open-close cycles, even when subjected to relatively low pressure (e.g., static water head of the RWT).

The licensee's response to the initial Dragon valve leakage problem at the end of the 1990 Unit 1 outage was positive. The licensee held phone conversations with the valve vendor about the indicator and

possible disk-to-seat differential expansion rates (initially it was thought that the valve leak might have been due to differential expansion when heated). At the time of the original incident, the licensee checked the general valve condition throughout both plants and found no egregious problems. NPWOs were issued on both units to remove these valves' indicators whenever work occurred on them for some other reason. There was no wholesale indicator removal due to ALARA considerations. The licensee generated an in-house event report and a night order familiarizing the non-licensed operators with the potential problem.

As a result of the second occurrence of the Dragon valve problem during this report period, the inspectors reviewed valve conditions in a typical, highly (valve) populated, accessible space - the Unit 1 pipe tunnel. Of the 19 valves inspected, seven were found with the indicator against the valve body; none of these seven [open ended vent and drain] valves had active leakage. One of the seven had evidence of previous leaking but was shut. Ten valves were found with the indicator not against the valve body. One of the ten also had evidence of previous leakage. Two valves were found with their position indicator removed, indicating licensee activity as discussed above. It was noted that the licensee had just pressurized all the Unit 1 ECCS systems for a leak revealing test to identify potential outage work items. No overt leakage was noted. Additionally, both units' RCS unidentified leakage was within TS limits. The inspectors concluded that gross leakage was not a widespread problem at present.

The licensee response for the RDT drain valve occurrence during this inspection period was also positive. The licensee's staff subsequently inspected valves in the HPSI, LPSI, and Containment Spray piping, and released for immediate work NPWOs to remove 31 other position indicators. The ECCS system engineer was reviewing plan and elevation drawings for the potential performance of indicator removal in valve groupings due to ALARA considerations. There are in excess of 300 Dragon valves per unit in the RABs (safety-related and non-safety-related). An operations night order with a supportive drawing described concerns during operation of the subject valves was re-issued. A REA was issued regarding Dragon valve replacement and/or repair options (e.g., seat replacement); approval action was accelerated by the most recent indicator problem. The repair options may be effected by subsequent engineering results.

The licensee and inspectors consider the problems with the Dragon valves to date as potential precursors to more complex problems. The licensee's engineering division continues to pursue this issue.

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):

- HCV 09-2A Unit 2 MFIV Nitrogen Leak Repair, and
- PCV 8801 Unit 2 Steam Bypass Valve.

The inspector reviewed radioactive liquid release 91-62 from the 1A waste monitor tank to the discharge canal per OP 1-0510022, Rev 33, Controlled Liquid Release to the Circulating Water Discharge. Several lines in the control room discharge permit had not been initialed where required. The form was quite user unfriendly in this area. Since the data was recorded and initials had little to do with actual performance, this form was identified to the human factors group for review. A greatly improved discharge permit form was developed by the end of the inspection period.

On August 29, Unit 2 was downpowered to 90% power per OP 2-0030123, Rev 16, Reactor Operating Guidelines During Steady State and Scheduled Load Changes, and OP 2-0030125, Rev 13, Turbine Shutdown Full Load to Zero Load. The control room operators coordinated well with the load dispatcher, between themselves, and with the outside plant operators and involved technical groups. They smoothly reduced power for the turbine throttle valve test discussed in paragraph 3.e.

The inspectors reviewed quality assurance activities and findings concerning plant operations to determine if the objectives were being met. The following QC 3900 deficiency reports/ activities were reviewed:

- M91-307 May 23, 1991 Radiological Material Shipment 91-24,
- M91-318 May 30, 1991 Unit 1 Charging pump repairs,
- M91-321 June 4, 1991 MV 2508 work, and
- M91-436 August 2,1991 ICW lube water restraint work.

The surveillances/reports had findings and positive results. These resulted in two NCRs and a procedure change.

The posting of required notices to workers was reviewed. The observed postings at the plant access points and the permanent RCA access points met requirements.

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.

3. 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 2-0810050, Rev 14, Main Steam/Feedwater Isolation Valves Periodic Test.

b. OP 1-2200050, Rev 58, Emergency Diesel Generator Periodic Test and General Operating Instructions - 1A EDG

c. OP 1-2200050, Rev 58, Emergency Diesel Generator Periodic Test and General Operating Instructions - 1B EDG. During the performance of this surveillance, the inspector observed two negative points:

- The 1B EDG room floor paint was peeling in patches approaching 3 inches by 3 inches in size. The paint patches had little shear strength and broke apart in the wind swirl created by the EDG radiator cooling fans. Since the patches did not appear to be lodging in the EDG radiators or entering the electrical generator cooling ducts, they did not appear to be an immediate safety problem. After the surveillance was completed, the licensee took positive action to remove the loose paint from the EDG room floor.

- A standing puddle of oil was observed under the 1B2 engine oil pan between the large I-beams that form the EDG skid. This had been observed in the past and required routine cleaning to prevent it from becoming a fire hazard. Though the licensee had been cleaning this oil buildup, more than a normal amount was noted at the time of the test. As noted in previous IRs, the licensee had almost completed repairs to a large oil leak under the 1B2 oil pan but minor seepage has persisted. The leak has been scheduled for final repair during the October, 1991, outage. The licensee immediately cleaned up the standing oil when it was identified.

Overall, both EDG tests were positive with all support systems operating as designed. The EDGs evenly came up to required speed and output levels.

d. On August 22, The inspector witnessed the periodic leak testing of the Unit 1 Emergency escape hatch (air lock) per OP 1300052, Rev 25, Airlock Periodic Air Testing, Section 8.2. This review included conformance to the RWP, conformance with safety requirements such as testing for oxygen prior to allowing persons to enter the air lock, and procedural adherence during the test. The health physics technician properly monitored for neutron radiation inside the air lock. The test included testing the inner and outer door seals to 10 psig and testing the air lock itself to 40 psig. The overall leak rate was measured to be 3075 SCCM. That was less than the previous test result and only a small portion of the allowed 45,400 SCCM leak rate. These test activities were also witnessed by an auditor from the licensee's Nuclear Assurance Division.

The health physics staff had placed only one [clean] stepoff pad at the escape airlock entrance hatch, leaving no space outside in which to remove anti-contamination coveralls. The two mechanics who had entered the air lock to support the leak test both removed their anti-contamination coveralls inside the air lock while bent over and standing on one foot. They then accomplished the particularly difficult task of stepping through the small hatch without touching anything to remove the last coverall leg and bootee while standing on the stepoff pad outside. The inspector requested that the licensee consider providing more room outside the air lock for this activity.

e. On August 29, the inspector observed the turbine valve test per AP 0010125, Rev 38, Schedule of Periodic Tests, Checks, and Calibrations, Check sheet 4, and OP 2-0030150, Rev 31, Secondary Plant Operating Checks and Tests, Section 8.1, Turbine Valve Test. Portions were observed from both the control room and the turbine deck. Test control per the procedure was excellent, involving the NPS, ANPS, and NWE as well as control room and outside operators. The STA also witnessed the turbine valve performance. The testing personnel assured themselves of the correct performance of each individual valve by both local observation and control room indication prior to proceeding to the next one. The testing was successful. Control room procedural control and communication were excellent.

In summary, the observed surveillances were well performed and coordinated.

4. Moderator Temperature Coefficient Determination (Unit 1) (61708, 61726)

On August 26, the licensee conducted a determination of moderator temperature coefficient on Unit 1 per OP 3200051, Rev 8, At Power Determination of Moderator Temperature Coefficient and Power Coefficient. This determination was made to comply with TS 4.1.1.4.2. This was the first infrequently performed test that invoked new AP 0010020, Rev 0, Conduct of Infrequently Performed Tests or Evolutions at St. Lucie Plant. The AP required special management involvement and pre-briefing by a designated management person. It also established special shift turnover requirements. The preparations were thorough, the pre-briefing was thorough, and run 1 of the test well performed. At the start of run two, CEA 7-1, the CEA being manipulated by the test, dropped to the bottom of its travel. CEA recovery per ONOP 1-0110030, Rev 24, CEA Off-Normal Operation and Realignment, was timely and professional. The CEA was retrieved in less than 30 minutes. The plant was returned to 100 percent power operation. The test was aborted for the night. The licensee staff found that enough data had been collected during the one run to make the test successful.

5. Maintenance Observation (62703)

Station maintenance activities involving selected safety-related systems and components were observed/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 62/7514 provided work control instruction for the replacement of the open limit switch on PCV 8801, which is one of the steam bypass valves to the main condenser. This work went smoothly and was well coordinated with the operating staff.

b. NPWO 64/6251 for Unit 2 provided administrative control of leak repair of the MFIV HCV-09-2A accumulator nitrogen line. This accumulator provided the motive force for valve closing. A tubing elbow on the accumulator nitrogen line had leaked and was replaced by a curved piece of stainless tubing. An existing fitting received the new tubing and ferrule-lock connector.

The above fitting was to be re-installed with a sealant. The I&C department personnel started to use a Team, Inc., compound called PRI-102N. At that point, the inspectors questioned whether the technicians were aware of the need to cure that sealant at elevated temperatures. The supervisor and work crew were not aware of this requirement but took steps to ensure proper curing during the repair effort.

This requirement was identified in previous NCV 335,389/91-04-01 (inspection period ended March 18, 1991). Corrective action for the NCV mentioned above resulted in Rev 3 to AP 0010507, Control of Chemicals and Materials for the Maintenance of Plant Systems, distributed within two weeks of its April 4, 1991, issue date. Procedure page 14 listed appropriate actions for the curing of this sealant. The licensee's OIN that signified the departmental closure of the NCV corrective action was signed off August 14, 1991 by the department head designee. The OIN did not recommend training on the particular procedure revision and the training department, during their review of procedure Rev 3, did not independently deem additional training to be required. The licensing department closure of the OIN (August 27,1991) noted no exceptions to the final closure of the OIN. The corrective action regarding the NCV met the requirements of procedure QI 16-PR/PSL-1, Rev 23, Corrective Action. Paragraph 4.2 of this procedure required that the department heads investigate and provide action to preclude recurrence of a non-compliance. In this case, the mechanical maintenance department addressed their non-compliance and afforded instruction to the other departments. The corrective action was somewhat shortsighted in that a more proactive means of informing the plant personnel was not also initiated.

QC was considering expansion of instruction for the department head or designee and/or final reviewer of the corrective action. A check list, that would consider that repetition prevention could improve the process, is being considered for addition to procedure QI 16-PR/PSL-1 regarding informing other groups and consideration of potential training items.

After I&C had the sealant problem, they took several steps to overcome the sealant instruction problem. The I&C department modified the catalog inquiry to alert future users of the PRI-102N sealant curing requirements. They informally requested that engineering have other sealants approved for use in safety-related applications for the upcoming outage. Heat cured sealants cannot be used in many applications.

During the nitrogen fill of the HCV 09-2A valve activation reservoir by the mechanical maintenance group, several problems were noted. NPWO 62/0372 invoked General Maintenance Procedure 2-M-018, Mechanical Maintenance Safety-Related Preventive Maintenance Program, PMs 1601 to 1604, which cover the MFIV maintenance. The problems and resolutions were as follows:

- These particular procedures were choppy and did not readily flow. Sections within the PMs were not chronological or logical in some instances, making them difficult to follow. The assigned maintenance engineer was reorganizing and clarifying the PMs to alleviate this problem.

- The applicable reservoir pressurization graph from the applicable technical manual (Anchor Darling #2998-11467) did not clearly identify the intended temperature measurement location for temperature correction during pressurization. The graph used the ambiguous term "environmental temperature," a phrase that could be construed several ways. The method used during the observed performance involved taking ambient temperature adjacent to the valve in the steam trestle space. Taking the reservoir's temperature by direct contact would reduce the required reservoir fill pressure, therefore the observed method was conservative in that a higher pressure was achieved during the filling. Available reference material (T/M and EPRI [NMAC]) supported the contact temperature measurement. The licensee did change the procedure in this regard.

- The licensee judged the availability of nitrogen gas for pressurizing the MFIV reservoirs by using a not-routinely-calibrated tank regulator gage on the portable nitrogen tanks. The tank regulator gage indicated sufficient pressure to properly pressurize the reservoir. However, during the filling, the gage of record mounted on the valve made it obvious that tank pressure was insufficient. A third gas tank was hurriedly obtained and used to prevent exceeding MFIV LCOs. The licensee planned to enhance the tank staging instruction.

The problems with sealant and MFIV work discussed above were worthy of management attention and were discussed at the exit with plant management. Licensee actions regarding these issues did aid in remedying them.

6. Review of Periodic and Special Reports (90713)

The inspector reviewed special report serial L-91-233, dated August 26, 1991, per Unit 1 and 2 TS 3.3.3.4 and 6.9.2. This report addressed removing the site meteorological station from service for more than seven days to completely replace the tower and equipment. This replacement was previously discussed in IR 389/91-16, paragraph 2b. The special report was accurate but acknowledged that it was [7 days] late. This lateness was due to a very infrequent oversight. It is not being cited as a violation because of the rare occurrence and no safety significance.

7. Exit Interview (30703)

The inspection scope and findings were summarized on September 20, 1990, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

8. Abbreviations, Acronyms, and Initialisms

ALARA	As Low as Reasonably Achievable (radiation exposure)
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
FT	Flow Transmitter
gpm	Gallon(s) Per Minute (flow rate)
HCV	Hydraulic Control Valve
HPSI	High Pressure Safety Injection (system)
HVE	Heating and Ventilating Exhaust (fan, system, etc.)
IR	[NRC] Inspection Report
LCO	TS Limiting Condition for Operation
LPSI	Low Pressure Safety Injection (system)
MFIV	Main Feed Isolation Valve
MTC	Moderator Temperature Coefficient
MV	Motorized Valve
NCR	Non Conformance Report
NCV	NonCited Violation (of NRC requirements)
NMAC	Nuclear Maintenance Application Center
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order

NRC	Nuclear Regulatory Commission
NWE	Nuclear Watch Engineer
OIN	Open Item Notice [licensee form]
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PCV	Pressure Control Valve
QI	Quality Instruction
RAB	Reactor Auxiliary Building
RCS	Reactor Coolant System
RDT	Reactor Drain Tank
REA	Request for Engineering Assistance
Rev	Revision
RWP	Radiation Work Permit
RWT	Refueling Water Tank
SCCM	Standard Cubic Centimeters per Minute
SDC	Shut Down Cooling
SNPO	Senior Nuclear Plant [unlicensed] Operator
SRO	Senior Reactor [licensed] Operator
STA	Shift Technical Advisor
T/M	Technical Manual
TS	Technical Specification(s)