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# CHAPTER 5

# REACTOR COOLANT SYSTEM

This chapter was originally prepared to describe the reactor coolant system (RCS) during the initial fuel cycle. Much of the original text is retained for historical record. However, this report has been revised to include the changes due to extended power uprate (EPU). The EPU will increase the power level from the stretch power of 2700 MWt to 3020 MWt. This increase of approximately 12% has a negligible impact on the structural evaluations of the RCS. Consequently, the EPU does not have a significant impact on the design bases of the RCS.

## 5.1 SUMMARY DESCRIPTION

The function of the reactor coolant system is to remove heat from the reactor core and transfer it to the secondary (steam generating) system. In a pressurized water reactor the steam generators represent the points of separation between the reactor coolant system and the main steam system. The steam generators are vertical U-tube heat exchangers in which heat is transferred from the reactor coolant to the main steam system. Reactor coolant is separated from the boiler water by the steam generator tube sheet. The reactor coolant system is a closed system which forms a barrier to the release of radioactive materials into the containment.

Plan and elevation views of the arrangement of the reactor coolant system are shown in Figures 5.1-1 and 1.2-11, respectively. The piping and instrumentation (P&I) diagram of the reactor coolant system is shown in Figure 5.1-3. The major components of the system are the reactor vessel, two heat transfer loops, each containing one steam generator and two reactor coolant pumps, a pressurizer connected to the loop 1B reactor vessel outlet pipe; and connecting inlet and outlet, spray and surge line piping. A quench tank is provided to receive, condense, and cool steam discharges from the pressurizer safety and power operated relief valves. All components are located inside the containment, and the relationship of the equipment arrangement to the containment structure is shown in Figure 1.2-7 through 1.2-11.

Table 5.1-3 shows the principal pressures, temperatures, flow rates and coolant volumes of the reactor coolant system components under pre-stretch normal steady state, full power operating conditions by means of numbered locations (See Figure 5.1-3). Figure 5.1-3 has a detailed representation of the reactor coolant system. Instrumentation provided for operation and control of the system is described in Section 7.

System pressure is maintained by regulating the water temperature in the pressurizer where steam and water are held in thermal equilibrium. Steam is either formed by the pressurizer heaters or condensed by the pressurizer spray to limit the pressure variations caused by contraction or expansion of the reactor coolant. The pressurizer is located with its base at a higher elevation than the reactor coolant loop piping. This eliminates the need for a separate pressurizer drain, and ensures that the pressurizer is drained before maintenance operations. The average temperature of the reactor coolant varies with power level, and the fluid expands or contracts, changing the pressurizer water level.

To maintain reactor coolant chemistry within the prescribed limits given in the Technical Specifications, and to control pressurizer water level, a continuous but variable letdown flow from loop 1B1 upstream of the reactor coolant pump is maintained. This flow is automatically controlled by pressurizer level. Constant coolant makeup is added by the charging pumps in the chemical and volume control system shown in figures 9.3-4 and 9.3-5. The charging flow is also used to alter the boron concentration or chemistry of the reactor coolant.

An inlet nozzle on each of the four reactor vessel cold leg pipes allows injection of borated water into the reactor vessel from the safety injection system (described in Section 6.3) in the event emergency core cooling is needed. During a normal plant shutdown these nozzles are also used to supply shutdown cooling flow from the low pressure safety injection pumps. An outlet nozzle on each reactor vessel hot leg pipe is used for shutdown cooling flow circulation.

Vents and drains in the reactor coolant system are provided to permit draining the reactor coolant system to the waste management system for the maintenance operations. A 2" drain line with a remote operated valve is provided on the quench tank for gravity transfer of the quench tank contents to the waste management system following a pressurizer relief valve or safety valve discharge. Other reactor coolant loop penetrations include sampling connections (Section 9.3.2) and instrument connections. The nozzle identifications are shown in Figures 5.1-1 and 1.2-11.

Overpressure protection is provided by two pilot solenoid-operated relief valves and three spring-loaded ASME Code safety valves flange-connected to the top of the pressurizer. Steam discharged from the valves is cooled and condensed by water in the pressurizer quench tank. In the unlikely event that the discharge exceeds the capacity of the quench tank, the tank can be relieved to the containment vent header. A rupture disc discharging to the containment atmosphere is also provided on the quench tank as backup to the quench tank safety valves. The quench tank is located at a level lower than the pressurizer safety and relief valves on containment floor elevation 62'. This ensures that any power operated relief valve or pressurizer safety valve leakage or discharge drains to the quench tank.

Overpressure protection for the secondary side of each steam generator is provided by eight ASME Code safety valves located on each of the main steam lines upstream of the steam line isolation valves. The steam bypass control system is equipped with four steam dump valves and one turbine bypass valve which serve to minimize challenges to the secondary safety valves following a partial load rejection and other transient conditions. The secondary pressure protection is described in Section 5.5.1.2.

Where required to reduce heat losses and protect personnel from contact with equipment operating above 125°F, components and piping in the reactor coolant system are insulated with a material compatible with the temperatures involved. All insulation material used on stainless steel has a low soluble chloride and other halide content to minimize the possibility of stress corrosion of stainless steel. No aluminum insulation, foil or structure is used.

The parameters of the reactor coolant system are listed in Table 5.1-1.

TABLE 5.1-1

PARAMETERS OF REACTOR COOLANT SYSTEM

| | |
|---|---|
| Design Thermal Power, MWt | 3050* |
| Btu/hr. | $10.407 \times 10^9$ |
| Design Pressure, psig | 2485 |
| Design Temperature (Except Pressurizer), F | 650 |
| Pressurizer Design Temperature, F | 700 |
| Coolant Flow Rate, lb./hr. | $143.8 \times 10^6$ |
| Cold Leg Temperature, Operating, F | 551.0 |
| Average Temperature, Operating, F | 580.8 |
| Hot Leg Temperature, Operating, F | 606.0 |
| Normal Operating Pressure, psig | 2235 |
| System Water Volume, ft.$^3$ (Without Pressurizer) | 9705** |
| Pressurizer Water Volume, ft.$^3$ | 800 |
| Pressurizer Steam Volume, ft.$^3$ | 700 |

The major components of the reactor coolant system are surrounded by concrete structures which provide support, radiation shielding and missile protection. Detailed plant layout drawings illustrating principal dimensions of the reactor coolant system in relation to the surrounding concrete structures are shown in Figures 1.2-7 through 1.2-11. The shield effectiveness of the surrounding concrete structures is described in Section 12.1. Reactor coolant system shielding permits limited access to the containment during power operation. The reactor vessel sits in a thick concrete cavity formed by the primary shield. The entire reactor coolant system is enclosed by the secondary shield. This shielding reduces the dose rate within the containment outside the secondary shield to acceptable levels during full power operation.

* Thermal power including uncertainty and a net RCP heat input of 20 MWt.
** Cycle 15 data – Replacement Steam Generators with 0% Plugging

TABLE 5.1-2

NOZZLE IDENTIFICATION
(See Figure 5.1-1)

| Code Let. | Function | Pipe Size | End Preparation | Qty. |
|---|---|---|---|---|
| A | Pressurizer Surge | 12 SCH 160 | Butt Weld | 1 |
| B | Shutdown Cooling Outlet | 12 SCH 160 | Butt Weld | 1 |
| C | Safety Injection and Shutdown Cooling Inlet | 12 SCH 160 | Butt Weld | 4 |
| D | Pressurizer Spray | 3 SCH 160 | Butt Weld | 2 |
| E | Charging Inlet | 2 SCH 160 | Butt Weld | 2 |
| F | Letdown & Drain | 2 SCH 160 | Butt Weld | 1 |
| G | Drain | 2 SCH 160 | Butt Weld | 4 |
| H | Temp. Measurement, RTD | | Socket Weld | 25 |
| J | Flow Measurement | 3/4 SCH 160 | Socket Weld | 8 |
| K | Sampling | 3/4 SCH 160 | Socket Weld | 2 |
| L | Feedwater | 18 SCH 80 | Butt Weld | 2 |
| M | Steam Outlet | 34" | Butt Weld | 2 |
| N | Flow Measurement | 1" SCH 160 | Socket Weld | 8 |
| P | | | | |
| Q | | | | |
| R | | | | |
| S | Pump Middle Seal Vent & Pressure | 3/4" 1500# | R.F. Flange | 12 |
| T | Pump Upper Seal Vent & Pressure | 3/4" 1500# | R.F. Flange | 4 |
| U | Pump Lower Seal Vent & Pressure | 3/4" 150# | R.F. Flange | 4 |
| V | Pump Intergasket Leakage Monitor | 3/4" 150# | R.F. Flange | 4 |
| W | Pump and Motor Cooling Water Inlet | 1 1/2" 150# | R.F. Flange | 4 |
| X | Pump and Motor Cooling Water Outlet | 1 1/2" 150# | R.F. Flange | 4 |
| Y | O-Ring Seal Monitor Tube | 3/4" SCH 80 | Butt Weld | 2 |
| Z | Safety Valve | 3" 2500# | R.F. Flange | 3 |
| AA | Steam Generator Level | 1" SCH 80 | Butt Weld | 16 |
| AB | Steam Generator Pressure | 1" SCH 80 | Butt Weld | 2 |
| AC | Steam Generator Blowdown | 2” SCH 80 | Butt Weld | 2 |
| AD | Reactor Vessel Vent | 3/4 2500# | R.F. Flange | 1 |
| AE | Pressurizer Relief | 4" SCH 160 | Butt Weld | 1 |
| AF | Spray Nozzle | 4" SCH 160 | Butt Weld | 1 |

TABLE 5.1-3

DESIGN DATA
REACTOR COOLANT SYSTEM
VOLUMES

| Component | Volume ($Ft^3$) |
|---|---|
| Reactor Vessel | 4652 [(1)] |
| Steam Generators (Replacement) | 3396 |
| Reactor Coolant Pumps | 449 |
| Pressurizer | 1500 |
| Piping | - |
| Hot Leg | 280 |
| Cold Leg | 752 |
| Surge Line | 32 |
| Quench Tank | 209 |

(1) The Replacement RVCH has a calculated volume of 1.3 cubic feet less than the original.

ORIGINAL DESIGN PROCESS DATA POINT TABULATION**

| Parameters | | *Process Data Point Locations | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Description | Units | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| Pressure | PSIG | 2250 | 2239 | 2299 | 2278 | 2299 | 2239 | 2299 | 2299 |
| Temperature | °F | 653 | 567.4 | 539.7 | 567.4 | 539.7 | 567.4 | 539.7 | 539.7 |
| Weight Flow | lb/hr ($x10^6$) | - | 61 | 30.5 | 122 | 30.5 | 61 | 30.5 | 30.5 |
| Volume Flow | GPM ($x10^3$) | - | 166.4 | 80.0 | 333.7 | 80.0 | 166.4 | 80.8 | 80.8 |

* Data Point Locations indicated on P&ID, Figure 5.1-3
** Pre-Stretch Power values

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**Refer to Drawing**
**8770-40**

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | REACTOR COOLANT SYSTEM ARRANGEMENT-PLAN | Figure 5.1-1 |
|---|---|---|

DELETED

FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

Figure 5.1-2

**REFER TO DRAWING**

**8770-G-078, Sheets 110A & 110B**

| |
|---|
| FLORIDA POWER & LIGHT COMPANY<br>**ST. LUCIE PLANT UNIT 1** |
| FLOW DIAGRAM<br>REACTOR COOLANT SYSTEM<br><br>**FIGURE 5.1-3** |

## 5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

This Section discusses the measures employed to provide and maintain the integrity of the reactor coolant pressure boundary throughout plant design lifetime. The reactor coolant pressure boundary is shown in Figure 5.1-3. The reactor coolant pressure boundary is defined in accordance with Section 50.2 (v) of 10 CFR Part 50 to include all pressure containing components such as pressure vessels, piping, pumps and valves which are:

a) Part of the reactor coolant system, or

b) Connected to the reactor coolant system, up to and including any and all of the following:

   1) The outermost containment isolation valve in the system piping which penetrates the containment

   2) The second of two valves normally closed during normal reactor operation in system piping which does not penetrate the containment

   3) The reactor coolant system safety and relief valves

### 5.2.1 DESIGN OF REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

The design bases and normal system function are those used for the integrated design of the reactor coolant system or those which apply to all of the system components. Principal parameters for the reactor coolant system are listed in Table 5.1-1. The design bases applicable to each component are further discussed in Section 5.5.

Design parameters for both normal and transient conditions are derived from the performance objectives of the system and its components. The normal function of the system is described in the subsequent paragraph. The normal design transients and abnormal transients included in usage factors are discussed in Section 5.2.1.2.

5.2.1.1 Functional Performance Requirements

The function of the reactor coolant system is to remove heat from the reactor core and transfer it to the secondary system by the forced circulation of pressurized borated water. The borated water serves both as a coolant and neutron moderator. The reactor coolant system is designed for the normal operation of transferring 3034 MWt from the reactor core (3020 MWt) and reactor coolant pumps (14 MWt) to the steam generators.

The reactor coolant system also serves as a pressure boundary having a high degree of leak tightness. The integrity of this pressure boundary is assured by appropriate recognition of operating, seismic and/or accident stress loadings. The normal operating pressure of the reactor coolant system is approximately 2235 psig.

The system design temperature and pressure are conservatively established and exceed the combined normal operating value and those resulting from anticipated transients. The effects of instrument error and the response characteristics of the control system are included in the design rating of the systems. The change due to the anticipated transients also considers the effect of reactor core thermal lag, coolant transport time, system pressure drop and the characteristics of the safety and relief valves.

Test pressures for the system and individual components are in accordance with the codes given in Table 5.2-1. The ASME Code specifies that the hydrostatic test pressure shall be 125 percent of design pressure. The allowable number of such tests are limited to those allowed by usage factor analyses.

5.2.1.2 Transients Used in Design and Fatigue Analyses

The relocated TS component cyclic or transient limits table is contained in Table 5.2-1a. EC289971

The following design cyclic transients, which include conservative estimates of the operational requirements for the components, were used in the fatigue analyses required by the applicable codes listed in Table 5.2-1. (Note: Differences exist between the cycles and transients assumed in the design of Unit 1 and those assumed in the design of Unit 2. Further, there may also be unit differences with respect to those cycles and transients required by plant procedure to be tracked). The evaluation for a 60-year plant design life concludes the design cycles listed below, which were based on a 40-year design life, envelope the 60-year plant design life. See Section 18.3.2.1.

a) 500 heatup and cooldown cycles during the design life of the components in the system with heating and cooling at a rate of 100°F/hr. between 70°F and 532°F (653°F for the pressurizer). This is based on a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred. The heatup and cooldown rate of the system is administratively limited to a value that will assure that these limits will not be exceeded.

b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000.

c) 2,000 cycles of step power changes of 10 percent of full load. An increasing step change may occur between 15 percent and 90 percent of full load while a decreasing step change may occur between 100 percent and 25 percent of full load. This is based on a normal plant operation involving one cycle per week for 50 weeks of the year. Two weeks of the year are assumed required for refueling.

d) 10 cycles of system hydrostatic testing at 3110 psig and at a temperature of at least 60F above the nil ductility transition temperature (NDTT) of the component having the highest NDTT value. This is based on one initial hydrostatic test plus a major repair every four years for 36 years which includes equipment failure and normal plant cycles.

e) 200 cycles of leak testing at 2235 psig and at a temperature at least 60F above the NDTT of the components having the highest NDTT value. This is based on a normal plant operation involving five shutdowns for head removal or valve repair per year for 40 years.

f) $1 \times 10^{6}$ cycles of normal variations of ±100 psi and ±6F when at operating temperature and pressure. This was selected based on $1 \times 10^{6}$ cycles being equivalent to infinite cycles and thus the limiting stress is the endurance limit. ±100 psi is the maximum pressure fluctuation above the set point (2235 psig) before backup heaters come on or spray valves open. For conservatism, the temperature cycle developed for the pressurizer is used for all components.

g) 400 reactor trips from full load. This is based on one reactor trip per month for the life of the plant and included trips due to operator error and equipment faults. Note: This is a Level B “Upset” condition for the Replacement Steam Generator (RSG).

In addition to the above list of normal design transients, the following abnormal transients were also considered in arriving at a satisfactory usage factor as defined in Section III of the ASME Boiler and Pressure Vessel Code; however, these transients were not used to form the basis for the code design of the components.

a) 40 cycles of turbine trip from 100 percent power with delayed reactor trip. This is based on one reactor trip per year for the life of the plant considering failure of the turbine trip/reactor trip circuit as credible. Note: This is a Level B “Upset” condition for the RSG.

b) 40 cycles of complete loss of reactor coolant flow when at 100 percent power. This is based on one reactor trip per year for the life of the plant resulting from failure of electrical supply to the reactor coolant pumps. Note: This is a Level B “Upset” condition for the RSG.

c) 5 cycles of complete loss of secondary pressure. This transient would follow a steam line break. A steam line break is not considered credible in forming the basis for design of the reactor coolant system. However, system components will not fail structurally in the unlikely event that it does happen. The number of occurrences is an arbitrary selection. Note: This is a Level C “Emergency” condition for the RSG.

Pressure and temperature fluctuations resulting from the above transients are computed by means of computer simulations of the reactor coolant system. Computer output entailing time dependent physical parameters throughout the reactor coolant system are detailed in the component specifications. The component vendor then uses the specification transient curves as the basis for fatigue design.

Fatigue analysis for each component of the reactor coolant system is performed in accordance with the applicable ASME codes. As appropriate the combined effects of the load and thermal transients specified for each condition of cyclic operation are evaluated as a function of time. The evaluations are performed in a manner to yield the maximum range in stress intensity during the particular cyclic condition under consideration. In those cases where conservative results are produced, peak stresses due to pressure may be combined with those due to thermal transients by direct superposition. In addition, the results of analysis obtained for the most severe transient condition in a group may be applied in evaluating the cumulative effects of the entire group.

Pressure and thermal stress variations associated with the above design transients are included in the engineering design of each of the reactor coolant system components, piping, and supports. In addition, the loads and moments resulting from the design transients are included in the design of equipment support foundations and interfacing support structures for the equipment.

Pressure fluctuations associated with the transients apply to the following components and piping:

a) Four safety injection system discharge isolation check valves adjacent to reactor coolant loop and any piping and supports between these valves and reactor coolant system.

b) The two suction isolation valves on each of the two shutdown cooling lines and the piping and supports between these valves and the reactor coolant system.

c) The reactor coolant system safety and power-operated relief valves on the pressurizer.

d) Charging line piping and valves from and including the charging isolation valve to the reactor coolant system.

e) The pressurizer auxiliary spray line piping and valves to the reactor coolant system.

All components that are designed and fabricated as Class A vessels are analyzed in accordance with the ASME Code requirements. It is demonstrated that the maximum stress intensities and cumulative usage factors are in compliance with code values.

The analyses are performed for steady state and cyclic conditions as required by the certified design specifications. Certified analytical reports are required for the components. Verification of the adequacy of the calculation and compliance with code and design specification requirements is assured by an independent review.

Thermal stresses induced in the reactor vessel wall by gamma heating, in combination with stresses produced by other loading conditions, are considered in the design of the vessel. The stresses due to gamma heating are low in magnitude and do not contribute significantly to the maximum primary-plus-secondary stresses.

In addition to the design requirements for which design rules are explicitly stated in ASME Code Section III, including the rules applied in evaluating the cyclic effects of the transients listed above, supplementary design loading combinations and associated design stress limits are defined and applied in the design of the reactor coolant system components. These supplementary design loading combinations are applied and evaluated independently of all other design conditions. Specifically, the supplementary design loading combinations and associated design stress limits given in Table 5.2-2 are applied. Note: The supplementary loading combinations originally applied to the original steam generator (OSG) addressed pipe rupture and seismic loading combinations not addressed by the ASME Code of Record (1965 Edition through Winter 1967 Addenda). These loadings are addressed for the RSG in the certified design specification (CDS) as required by Section III of the ASME Code (1986 Edition, no addenda). See Note 1. Loadings for the replacement pressurizer are addressed in the CDS as required by Section III of the ASME Code (1998 Edition, 2000 addendum).

Limitations on the pressurization and heatup of the reactor coolant system are defined by that reactor coolant system material exhibiting the highest transition temperature until irradiation effects on the reactor vessel become dominant. The NDTT of the material used for reactor coolant system components is established in accordance with ASME Boiler and Pressure Vessel Code, Section III.

Design basis cyclic transients were revisited for the pressurizer surge line and nozzles to address thermal stratification and thermal stripping concerns raised by NRC Bulletin 88-11. This bulletin required licensees to visually inspect the surge line; to perform analyses to demonstrate that the surge line meets applicable design codes and other FSAR/regulatory requirements for the design life of the plant; to obtain data on thermal stratification, thermal striping and line deflection; and to perform detailed stress and fatigue analyses on the line to ensure compliance with applicable code requirements. As a result of this analysis which is documented in Reference 10, the NRC concluded (Reference 11) that the results of the analysis performed by the Combustion Engineering Owner's Group (CEOG) for this task may be used for FPL as the basis to update the plant specific code stress reports to demonstrate compliance with applicable Code requirements as requested in NRC Bulletin 88-11. The analysis developed a new set of design basis transients based on the collected data. The new set of design basis transients are provided in Reference 10. The total number of heatup-cooldown cycles remained unchanged at 500; however, the number of stratification cycles that occur during a heatup-cooldown cycle was changed. (See 3.9.2.2).

Note 1: The supplementary loading combinations originally applied to the original Reactor Vessel Closure Head (RVCH) addressed pipe rupture and seismic loading combinations not addressed by the ASME Code of Record (1965 Edition through winter 1967 Addenda). These loadings are addressed for the replacement RVCH in the Certified Design Specification (CDS) as required by Section III of the ASME Code 1989 Edition, No Addenda.

5.2.1.3 Applicable Codes

The codes adhered to and component classifications are listed in Table 5.2-1 and conform to 10 CFR Part 50, Section 50.55a.

| Component | Codes and Classes |
| --- | --- |
| Secondary Safety Valves | ASME Code for Pumps and Valves for Nuclear Power Class I, 1968 Draft |

Control Element Drive Mechanisms ASME Section III

The impact properties of all materials which form, a part of the pressure boundary meet the requirements of the ASME Boiler and Pressure Vessel Code Section III, Paragraph N330, at a temperature of 40 F.

5.2.1.4 Seismic Design

The reactor coolant system is designated seismic Class I and is designed to the criteria for load combinations and stresses which are presented in Table 5.2-2.

The design criteria established to consider the effects of pipe rupture include both longitudinal (slot) and circumferential (guillotine) type failures. These design criteria assume the possibility of a pipe break at any location within the reactor coolant pressure boundary wherever there is a change in direction except that a break initiating at a straight section of the reactor coolant system loop piping is considered unlikely.

The design approach is that the use of plastic instability and limit analysis methods of ASME III provides justification with the type of dynamic system analysis performed.

An elastic analyses is used to establish, or conform, loads which are specified for the design of seismic Class I components and supports.

Pumps and valves within the reactor coolant pressure boundary are classified as either active or inactive components. Active components are those whose operability is relied upon to perform a safety function as well as reactor shutdown function, during the transients or events considered in the respective operating condition categories. Inactive components are those whose operability (e.g., valve opening or closure, pump operation or trip) are not relied upon to perform the safety function during the transients or events considered in the respective operating condition categories. Thus, certain pumps and valves (classified as active components) within the reactor coolant pressure boundary are required not only to serve as pressure retaining components (as in the case of passive components such as vessels and piping) but also to operate reliably to perform a safety function such as safe shutdown of the reactor and mitigation of the consequences of a pipe break accident under the loading combinations considered in design. Table 5.2-3 lists those valves within the reactor coolant pressure boundary (RCPB) which are classified as active.

Operability assurance for Classes 2 and 3 active components is discussed in Section 3.9.2.4. This discussion is applicable to Class 1 active components.

5.2.1.5 Environmental Protection

The major components of the reactor coolant system are protected against environmental factors, including fires, flooding, internal missiles and seismic effects. The reactor coolant system is protected from environmental effects by the containment and shield building.

Fires

Refer to the Fire Protection Design Basis Document for the Fire Safety Analysis (Reference 13)

Flooding

There are no environmental hazards associated with flooding since the reactor coolant system is within the containment structure.

Missiles

Refer to Section 3.5.1 for discussion of missile considerations.

Seismic Effects

Refer to Section 3.7 for discussion of seismic effects.

## 5.2.2 OVERPRESSURE PROTECTION

Detailed structural analyses are performed by the component vendors and reviewed independently for all portions of the system. The welding materials used have physical properties superior to the materials which they join. Inspection procedures and tests specified and independently reviewed have been carried out to assure that pressure-containing components have the maximum integrity obtainable with present code-approved inspection techniques.

Low Temperature Overpressure Protection (LTOP) is provided by the power operated relief valves (PORVs) and the Overpressure Mitigation System (OMS) as discussed in Section 5.2.2.6. The protection provided by the PORVs precludes any overpressurizing transient from exceeding the pressure- temperature (P-T) operating limits presented in the Technical Specifications.

### 5.2.2.1 Reactor Coolant System and Main Steam Safety Valves

The reactor coolant system is protected against overpressure by three ASME Code approved safety valves. The secondary system is protected by the main steam safety valves.

The pressurizer safety valves are flanged mounted on the head of the pressurizer. They are totally enclosed, back pressure compensated, spring loaded safety valves. Parameters for these valves are given in Section 5.5.3.

The pressurizer safety valves are designed to limit the reactor coolant system pressure to less than 110 percent of design following a 100 percent loss of turbine-generator load without simultaneous reactor trip. The reactor is assumed to trip on a high pressurizer pressure signal. In determining the maximum steam flow through the pressurizer safety valves, the main steam safety valves are assumed to be operational. Conservative values for all system parameters, delay times, and core moderator coefficient are assumed. Overpressure protection is provided to the portions of the reactor coolant system which are at the highest pressure considering pump head, flow pressure drops and elevation head. The safety valves discharge through the relief line piping into the quench tank described in Section 5.5.4. Parameters for these valves are given in Table 5.5-4.

NUREG-0737 required utilities to evaluate the functional performance capabilities of PWR safety, PORV and block valves. This evaluation was submitted in References 1 and 2. Reference 4 documents the NRC review and acceptance for performance capabilities of pressurizer safety valves and PORVs. Three qualified ring settings were approved for use in the PSL Safety Relief Valves by Reference 1 which states that the qualified ring settings opened at pressures from 2462 to 2508 psia (-1.5% to +0.32% of the nominal set pressure), had stable behavior and closed with 8.1% to 15.7% blowdown. This indicates the valve was able to perform its safety function of opening, reliving pressure and closing with these three ring settings. Reference 15 states the ring setting used at PSL will be -55,-14 from a level position. Per reference 16, this results in a blowdown of approximately 10%. The issues related to output torque of the PORV block valve operators and pressurizer relief valve piping and supports were addressed in References 8 and 9 respectively. EC293169

Overpressure protection for the shell side of the steam generators and the main steam line piping up to the main steam isolation valve is provided by ASME Code, spring loaded, open bonnet safety valves which discharge to the atmosphere. Safety valves are flange mounted an each of the two main steam lines upstream of the steam line isolation valves outside the containment. Parameters for these valves are given in Table 5.5-2.

5.2.2.2 Other Pressure Relieving Devices

Piping and instrumentation diagrams show the location of pressure relieving devices for the reactor coolant system and the auxiliary and emergency systems connected to the reactor coolant system. The diagrams also show points of discharge of the pressure relieving devices.

A steam dump and bypass system mitigates or prevents overpressure conditions on the main steam system, but no credit is taken for this system in the analysis of the loss of turbine load.

Following a simultaneous turbine and reactor trip, the stored energy in the reactor coolant and nuclear fuel must be removed. If the steam flow path to the turbine is blocked, steam is dumped directly to the atmosphere or bypassed to the condenser. The steam dump and bypass system is described in Section 10.4.4 and the atmospheric dump system is described in Section 10.3.2.

5.2.2.3 Report on Overpressure Protection

The pressure relieving capacity of the RCPB is further described in the "Nuclear Steam Supply System Overpressure Protection Report" presented in Appendix 5A.

5.2.2.4 Mounting of Safety and Relief Valves

The mounting of safety valves and relief valves within the reactor coolant pressure boundary and on the main steam lines outside of the containment is in accordance with the applicable provisions of ASME Boiler and Pressure Vessel Code, Section III.

The pressurizer safety valves are connected to the flanged nozzles on the pressurizer. The loads which the nozzles must withstand during normal plant operation and when the valves are discharging steam are included in the specification for the pressurizer. The capability of the nozzles to withstand the loads over design life satisfies the requirements in the ASME Boiler and Pressure Vessel Code, Section III for Class A vessels.

In addition, limiting loads which may be applied to the outlet connections of the valves by the connecting piping are specified. The arrangement and support of this piping is such that the limiting loads are not exceeded for both the normal and relieving conditions. The limiting loads specified for the valves are obtained from the valve supplier.

NUREG-0737 required utilities to verify piping systems of PWR safety, PORV and block valves for normal, transient and accident conditions. This evaluation was submitted in Reference 3. Reference 4 documents the NRC review of the submittal which still has the qualification of the plant specific piping systems by analysis, under review. Per FPL letter L-89-455 (Reference 8) the open item, pertaining to the output torque of PSL-1 PORV block valves has been completed. Per FPL letter L-90-315 (Reference 9) the open item pertaining to the pressurizer relief valve piping and support evaluation is completed. Thus requirements of NUREG-0737, Item II.D.1 are satisfied.

For the main steam safety valves, the full discharge thrust loads of the valves are combined with pressure, weight, seismic and thermal loads for computing stresses in the mounting nozzle and the header. Bending and torsional stresses in the main steam line are computed for all safety valves in the line discharging concurrently or individually whichever yields the maximum load conditions. Supports and restraints for piping system keep stresses within allowable limits of the applicable code.

Relief valve installations are analyzed for steady state load conditions. To evaluate reaction force, both a static pressure term and a momentum term due to discharge jet velocity are considered. For multi-valve installations, analysis is restricted to individual and simultaneous valve discharge.

#### 5.2.2.5 Stress Limits for Anticipated Transients Without Reactor Scram

Analyses have been performed of the following anticipated transients assuming that no CEAs are inserted into the core during the transient:

1) CEA withdrawal
2) CEA drop
3) idle loop startup
4) loss of flow
5) boron dilution
6) excess load
7) loss of load
8) loss of feedwater
9) pressurizer safety valve failure
10) loss of normal on-site and off-site power

Transient ten is analyzed conservatively assuming insertion of one percent negative reactivity following reactor trip signal generation, since for this case the failures which initiate the transient also remove power from the CEDMs and allow the CEAs to insert. The results of these analyses were presented to the AEC in CENPD-41, Topical Report on Anticipated Transients Without Scram. For those cases where the postulated situation results in pressures considerably above the hydrostatic test pressure (3110 psig) some limited plastic deformation would occur at local regions of the reactor coolant pressure boundary; however, the integrity of the boundary against gross failures will be maintained.

5.2.2.6 Overpressure Mitigation for Solid Water, Low Temperature Operation

The Overpressure Mitigation System (OMS) provides low temperature overpressure protection (LTOP) for the reactor coolant system. OMS prevents exceeding the reactor vessel heat up and cool down pressure-temperature (P-T) operating limits presented in the Technical Specifications during periods of solid water operation. The P-T limits, described in Section 5.4.2, are designed to protect the reactor vessel from potential brittle fracture. The OMS pressure limits are based on two temperature dependent, low pressure range setpoints.

The OMS is designed to mitigate pressure transients by using the pressurizer Power Operated Relief Valves (PORVs) as the pressure relief mechanism. System operation is described in Section 7.6.1.3.

The OMS is designed to mitigate a pressure transient that could approach the P-T limits. The LTOP analysis is periodically revised when revisions to the P-T operating limits are required to account for changes in the adjusted reference temperature of the reactor vessel materials. The LTOP analysis has been performed to support the uprating to 3020 MWt and discussed in Reference 12 (previous analyses are retained as historical only in Reference 5, 6 and 7). A summary of the current overpressure mitigation analyses is provided in Appendix 5B.

REFERENCES FOR SECTIONS 5.2.1 AND 5.2.2


1. Letter R. E. Uhrig, Florida Power and Light Co., to D. G. Eisenhut, NRC, "St. Lucie Unit 1, Docket No. 50-335, Post-TMI Requirements, NUREG-0737, Item II.D.1, PWR Relief and Safety Valve Testing", L-82-277, July 9, 1982.
2. Letter R. E. Uhrig, Florida Power and Light Co., to D. G. Eisenhut, NRC, "St. Lucie Unit 1, Docket No. 50-335, Post-TMI Requirements, NUREG-0737, Item II.D.1, PWR Relief and Safety Valve Testing", L-82-353, August 13, 1982.
3. Letter R. E. Uhrig, Florida Power and Light Co., to D. G. Eisenhut, NRC, "St. Lucie Unit 1, Docket No. 50-335, Post-TMI Requirements, PWR Relief and Safety Valve Testing", L-82-564, December 30, 1982.
4. Letter, J. A. Norris, NRC, to C. 0. Woody, FPL, "NUREG-0737 Item II.D.1. Performance Testing of Relief and Safety Valves", May 11, 1989.
5. L-78-129 (4/13/78) - License Amendment #60.
6. L-87-122 (3/17/87) - License Amendment #81.
7. L-89-408 (12/5/89) - License Amendment #104.
8. Letter J. H. Goldberg, Florida Power and Light Co., to U. S. Nuclear Regulatory Commission, NUREG-0737 Item II.D.1, Performance Testing of Relief and Safety Valves, L-89-455, December 13, 1989.
9. Letter D. A. Sager, Florida Power and Light Co., to U. S. Nuclear Regulatory Commission, NUREG-0737 Item II.D.1, Performance Testing of Relief and Safety Valves, L-90-315, August 30, 1990.
10. ABB Combustion Engineering Report CEN-387-P, “Pressurizer Surge Line Flow Stratification Evaluation”, Rev. 1-P-A, C-E Owners Group, May 1994.
11. NRC Letter to C-E Owners Group, “Safety Evaluation for CEOG Report CEN-387-P, Revision 1, (Bulletin 88-11)”, July 14, 1993.
12. WCAP-17197-NP, Revision 1, “St. Lucie Unit 1 RCS Pressure and Temperature Limits and Low-Temperature Overpressure Protection Report for 54 Effective Full Power Years”, January 2012.
13. DBD-FP-1, Fire Protection Design Basis Document
14. L-2016-212 (12/22/2016) – License Amendment #241
15. Letter C.O. Woody, Florida Power and Light Co., to A.C. Thadani “Relief and Safety Valve Test Requirements,” L-86-114, March 18, 1988. EC293169

16. CEN-227, “Summary Report on the Operability of Pressurizer Safety Valves in CE Designed Plants,” December 1982. EC293169

## 5.2.3 MATERIAL CONSIDERATIONS

### 5.2.3.1 Materials Specification

Specifications that are used for the principal pressure retaining ferritic and austenitic materials that form the reactor coolant pressure boundary are given in Table 5.2-4. The chemical analysis of the plate material in the core region of the vessel and the as deposited weld material are listed in Table 5.2-4A. NDTT is discussed in Section 5.2.3.5.

### 5.2.3.2 Material Exposed to Coolant

Materials used in the pressure containing boundary of the reactor coolant system or exposed to the reactor coolant are chosen to minimize corrosion and have shown satisfactory performance in other operating reactor plants. A listing of materials is given in Table 5.2-5. The table shows materials of component construction as well as internal surface material normally exposed to reactor coolant. Valve materials in contact with the reactor coolant are austenitic stainless steel.

### 5.2.3.3 Insulation

Piping and components located inside the reactor containment vessel are insulated for thermal, personnel or anti-sweat requirements with a reflective-type, calcium silicate, or blanket-type material compatible with the temperature and functions involved. Metallic reflective insulation and calcium silicate blocks represent the large majority of NSSS insulation type, and are the original design. All insulation material used on stainless steel has a low soluble halide content to minimize the possibility of halide induced stress corrosion. The insulation of stainless steel pipe conforms completely to the requirements of Regulatory Guide 1.36. Prior to initial installation of insulation on stainless steel pipe, a coating of halide-free silicone paint is applied to the pipe as further protection. Subsequent installation(s) or reinstallation(s) of insulation on stainless steel pipe may be made without applying additional coating(s) of Halide free silicone paint.

The SG channel heads and primary nozzles and the hot leg elbows are insulated with fiberglass blankets. The insulation on the elbows has a stainless steel jacket and the insulation on the SG channel heads and primary nozzles is protected with a stainless steel wire mesh.

A fiberglass blanket insulation encapsulated in stainless steel is used on the flange stud area of the reactor vessel closure head to permit access to the head studs for removal and reinstallation of the head. The insulation system is composed of stainless steel sheet metal, fiberglass blankets, structural stainless steel framing, latch and strike connections and quick disconnect toggle locks to form a composite system which facilitates quick removal and installation.

Removable metal reflective or fiberglass blanket thermal installation is on weld areas of the reactor coolant system subject to inservice inspection. Nonremovable metal reflective type thermal insulation is on the reactor vessel.

The reactor vessel head dome is primarily insulated with approximately 3" to 6" thick stainless steel metal reflective insulation. Circular openings are provided in the dome insulation to accommodate the CEDM nozzles protruding from the vessel head. The metal reflective insulation has a flat top supported approximately 3" above the highest point of the reactor vessel dome which allows sufficient clearance for inspection tooling and visual bare head inspection. Removable insulation panels are located on the outer perimeter to allow access to the space between the bottom of insulation and the dome surface.

The reactor vessel below the flange is insulated with approximately 4-inch thickness of stainless steel reflective insulation with removable sections around the vessel nozzles to allow inservice inspection.

The possibility of leakage of reactor coolant onto the reactor vessel head or other part of the reactor coolant pressure boundary causing corrosion of the pressure boundary has been investigated by C-E.

Metal reflective insulation is used on the pressurizer upper head, shell, and skirt. Removable blanket insulation panels are used on the pressurizer bottom head. Flexible blanket-type insulation is used on portions of the spray lines and charging/letdown lines.

The thickness of insulation is such that the exterior surface temperature is not higher than approximately 50 F above the maximum containment ambient (120 F). Exterior surface temperature of the flange stud area insulation is not higher than 80°F above maximum containment ambient. All insulation support attachments were attached prior to final stress relief.

#### 5.2.3.4 Coolant Chemistry

Control of the reactor coolant chemistry is a function of the chemical and volume control system. Sample lines (refer to Section 9.3.2) from the reactor coolant system provide a means for taking periodic samples of the coolant for chemical analysis. All wetted surfaces in the reactor coolant system are compatible with the water chemistry. The water chemistry is to be maintained as indicated in Section 9.3.4.

#### 5.2.3.5 Fracture Toughness of Ferritic Materials

The material toughness test requirements are as follows:

##### 5.2.3.5.1 Reactor Vessel

Carbon and low-alloy steel materials which form a part of the pressure boundary meet the requirements of the ASME Code, Section III, Paragraph N-330 at a temperature of +40 F. It was an objective that the materials meet this requirement at +10 F. Charpy tests were performed and the results used to plot a transition curve of impact values vs. temperature extending from fully brittle to fully ductile behavior. The actual nil-ductility transition temperature of inlet and outlet nozzles, vessel, shell and head materials was determined by drop weight tests per ASTM E208. NDT was established by Charpy test. Drop weight tests were conducted and are presented in Table 5.2-6. See Note 1.

The maximum NDTT as obtained from the drop weight test is +20 F. The maximum temperature corresponding to the 50 ft.-lb. value of the Cv fracture energy is +37F (closure head dome plate Code No. C-20-1). The minimum upper shelf Cv energy value for the strong direction (RW) is 104 ft.-lbs. (closure head dome plate Code No. C-20-1). The data for the weak direction was not obtained. The Charpy V-Notch results are shown in Figures 5.2-1 through 5.2-28. See Note 1.

Initial $RT_{NDT}$, copper and nickel values for the reactor vessel beltline plate and weld materials are also listed in Section 5.4.3 Tables 5.4-7 and Tables 5.4-8.

Note 1: The Reactor Vessel Closure Head has been replaced and this information is for historical purposes only. Figures 5.2-24 through 5.2-28 have been marked "For historical information only". For the replacement RVCH material, see Table 5.2-6.

5.2.3.5.2 Steam Generator and Pressurizer

It was an objective that impact properties of all ferritic steel materials which form a part of the pressure boundary shall meet the requirements of the ASME Code Section III, at a temperature of +10°F; alternate higher temperature levels up to 40°F were permitted only if the material failed at +10°F.

For the Replacement Steam Generators (RSGs), the $RT_{NDT}$ for each pressure boundary plate, forging or weld is equal to or less than 0°F. Typically, these temperatures range from -70° to -20°F.

Test results for Charpy V-notch and drop weight values for RSG pressure boundaries are presented in Tables 5.2-8 and 5.2-9.

For the replacement pressurizer, the $RT_{NDT}$ for each pressure boundary forging and associated weld is no higher than 17°F. The manway bolting material meets 45 ft-lbs, 25 mils lateral expansion at 60°F. EC291392
Test results for replacement pressurizer parts are presented in Table 5.2-7.

5.2.3.5.3 Reactor Coolant Piping

Materials used to fabricate the pipe and fittings have been specified, examined and tested to satisfy as a minimum the requirements of Chapter I-III of ANS Code for Nuclear Power Piping B31.7, Class 1.

Impact properties of carbon steel materials, including welds, have a minimum V-Notch value of 20 ft.-lb. (average of three specimens) or 15 ft.-lb. (any individual specimen) at 40°F. It is a design objective that the materials meet this requirement at 10°F. Weld procedure qualifications and weld metal certifications records document impact properties of welds. The results are presented in Table 5.2-10.

5.2.3.5.4 Location of Limiting Values

The identification and location of the material relating to the limiting values identified above are as follows:

| | LOCATION | MATERIAL | LIMITING VALUE |
|---|---|---|---|
| a) | Reactor Vessel Flange | Forging | NDTT + 10°F |
| | Reactor Vessel Outlet Nozzle Extension | Forging | NDTT + 10°F |
| b) | Closure Head Dome | Plate | 50 ft.-lb. value +37°F |
| c) | Upper Shell Plate | Plate | Upper Shelf Energy 104 ft.-lbs. |
| d) | Closure Head Dome | Plate | Upper Shelf Energy 104 ft.-lbs. |

5.2.3.5.5 Reactor Vessel Beltline Materials

Predictions of end of life adjusted reference temperature (adjusted $RT_{NDT}$) corresponding to the shift at the 30 ft.-lb. value of Charpy V-Notch fracture energy are made for the beltline region plates and welds. These predictions are calculated using the initial reference temperature, a shift to account for irradiation embrittlement and a margin term to account for uncertainty in the initial measurement and the prediction method. Current predictions are maintained in the NRC docket under 10 CFR 50.61 as noted in Section 5.4.3. The predictions indicate that end of life transition temperatures for the beltline materials are safely below the 10 CFR 50.61 screening limit. Predictions are also used as a basis for heat up and cooldown curves as noted in Section 5.4.2. The predictions are benchmarked by the reactor vessel surveillance program (Section 5.4.4).

The predicted end-of-life transition temperature is based on shift correlations using residual chemistry of the beltline region plates and weldments and on fracture energy data for the strong (RW) direction in the beltline region plates. There are presently no weak (WR) direction values available for the plates, but experience has shown that the transition temperatures are within the same data scatter range for WR and RW orientations. These RW orientation values can, therefore, be accepted as indicative of the WR orientation values.

This will be verified through testing of the samples included in the reactor vessel surveillance program (Section 5.4.4) which includes both WR (or transversely) oriented specimens and RW (or longitudinally) oriented samples.

At the time of the vessel fabrication there were no baseline Cv impact test results for beltline region welds from which a reference temperature could be established. Measured reference temperature ($RT_{NDT}$) values were later determined for two weld heats when the unirradiated surveillance baseline specimens (which includes transverse weld metal specimens) were tested. An $RT_{NDT}$ value was obtained for the intermediate to lower shell girth weld from the St. Lucie surveillance program and the lower shell longitudinal weld $RT_{NDT}$ value was obtained from a surveillance program for another reactor vessel that was manufactured by Combustion Engineering with the same weld heat (Reference 1). The intermediate shell longitudinal weld $RT_{NDT}$ is based on a generic value, as identified in 10 CFR 50.61 and the margin term is increased accordingly as compared to those materials with measured $RT_{NDT}$ values. The determination of the $RT_{NDT}$ values for the reactor vessel beltline welds allows for accurate prediction of end of life transition temperature for these welds.

The minimum upper-shelf impact energy value that will be acceptable for continued reactor operation toward the end-of-service life of the vessel is 50 ft.-lbs.

5.2.3.6 Measures to Avoid Austenitic Stainless Steel Sensitization*

All raw austenitic stainless steel material, both wrought and cast, employed in the fabrication of the major components in the reactor coolant system, is supplied in the annealed condition as specified by the pertinent ASTM or ASME Code; viz, 1850-2050°F for 1/2-1 hour per inch of thickness and rapidly cooled to below 700°F. The time at temperature is determined by the size and type of component. For example, reactor coolant pump casings which are cast from CF8M are usually subject to more than one solution anneal and, therefore, the time at temperature is limited to 1/2 hour per inch of thickness. Solution heat treatment is not performed on completed or partially fabricated components. Rather, the extent of chromium carbide precipitation is controlled during all stages of fabrication as described below.

a. Exposure of unstabilized austenitic 3XX stainless steels to temperatures ranging from 300-1600°F will result in carbide precipitation, or sensitization, depends on the temperature, the time at that temperature and, also, the carbon content. Severe sensitization is defined as a continuous grain boundary chromium iron carbide network. This condition induces susceptibility to intergranular corrosion in oxygenated aqueous environments, as well as those containing halides. Such a metallurgical structure will readily fail the Strauss Test, ASTM A393. Discontinuous precipitates, i.e., an intermittent grain boundary carbide network, is not susceptible to intergranular corrosion in a PWR environment. Weld heat affected zone sensitized austenitic stainless steels, which will fail the Strauss Test, ASTM A393, is avoided by careful control of weld heat input, interpass temperature, carbon content and reannealing.

* Note: For the replacement steam generators, sensitization is not an issue in non-annealed welding applications as L-Grade materials are used. BWI conforms with Regulatory Guides 1.31, 1.43 and 1.44 to avoid stainless steel sensitization.

For the replacement pressurizer, sensitization is not an issue in non-annealed welding application as L-Grade and low carbon content ($C \leq .03\%$) materials are used. Framatome-ANP conforms with Regulatory Guides 1.31, 1.43 and 1.44 to avoid stainless steel sensitization.

A weld input of less than 60kJ/inch is used during most fabrication phases of the T304 stainless steel core support structure. Higher heat inputs are used in some heavy section weld joints. Freedom from weld heat-affected zone sensitization in these higher input weldments is demonstrated with weld runoff samples produced at the time of component welding of material having a carbon content greater than the highest carbon content of those heats of steel being fabricated. Specimens so provided are subjected to the Strauss Test, ASTM A393.

When stainless steel safe ends are required on component nozzles or piping, fabrication techniques and sequencing require that, the stainless steel piece be welded to the component after final stress relief. This is accomplished by welding an Inconel overlap, on the end of the nozzle. Following final stress relief of the component, the stainless steel safe end is welded to the Inconel overlay, using Inconel weld rods. Vendor fabrication and welding procedures for auxiliary components in the safety injection and shutdown cooling systems are reviewed to assure that sensitization is not induced during manufacture.

PC/M 09077M implemented during SL1-23, mitigated cold leg charging, spray, and intermediate drain nozzles and the “A” hot leg drain nozzle Alloy 600 dissimilar metal (DM) welds by repair and replacement of the DM welds and safe ends. The replacement materials are 316 stainless steel with welding materials of 309L or 316L. Prior to welding the safe end to the nozzle, two layers of ER309L are deposited on the ID and face of the weld prep, followed by two layers of ER316L. Once the nozzle buttering is complete, the 316L safe end is welded to the buttering using a groove weld of ER316L filler.

b. During normal operating conditions austenitic stainless steel surfaces are not exposed to water environments containing over 0.10ppm dissolved oxygen when at temperatures over 250°F in compliance with the water chemistry specifications given in Table 9.3-8.

c. The delta ferrite content of the austenitic stainless steel weld metals used in the fabrication of the major components of the reactor coolant system and of the field welds are controlled to 5-18% in the as-deposited condition. Delta ferrite content is confirmed from chemical analysis and the Schaeffler or McKay diagrams. In addition, a calibrated ferrite measuring instrument, Severn Gauge or similar is used. The ferrite requirement is met for each heat and/or lot of filler metal used in fabrication and field welding.

The delta ferrite content of completed shop and field welds is determined by means of a calibrated ferrite measuring instrument as part of the quality assurance program and the delta ferrite phase must be greater than 5%. (Note: This does not apply to the replacement steam generators because castings are not used on the primary side). The delta ferrite content of duplex austenitic/ferrite content of duplex austenitic/ferrite castings is controlled to 5-25%. Delta ferrite is confirmed from chemical analysis and the Schaeffler diagram and the use of a calibrated ferrite measuring instrument. Delta ferrite in the 5-18% range provides austenitic weld filler metal with optimum resistance to hot cracking. All weld filler metals of the types 308, 308C, 309 and 309L used on shop and field welds are purchased with a chemistry balance capable of providing a delta ferrite content of 5-18% based on the Schaeffler or McKay diagrams. A magnetic measuring device such as the Severn Gauge is used on completed welds to assure the required ferrite content.

Hot cracking in austenitic stainless steel field welds is prevented by the purchase of filler metal to an analysis which will yield a delta ferrite content of 5-15% in an undiluted weld metal analysis. The delta ferrite content is determined by application of the undiluted weld deposit analysis to the Schaeffler Diagram.

Each manufacturer, fabricator, erector and contractor is responsible for the quality of the welding done by his organization. Appropriate tests are conducted prior to any production work to determine: (1) the suitability of the welding process parameters, filler metals and thermal treatments for achieving weldments which will meet specification requirements, and (2) the ability to each welder and welding operator to make sound welds under standardized test conditions. Tests are conducted in accordance with the ASME Boiler and Pressure Vessel Code, Section IX, and where applicable, to those special requirements of ASME Boiler and Pressure Vessel Code, Section III and VIII. The tests also conform to applicable local rules and regulations.

A written welding procedure specification, containing the information detailed in Form QA-10 of ASME Section IX, Appendix II and the qualification test data, containing the information detailed in Form Q-1 of ASME Section IX, Appendix II are provided for code compliance and applicability review four weeks before initiation of contract work.

A certificate of welder performance qualification test, containing the information detailed in Form Q-1G of ASME Section IX, Appendix II is kept on file by the seller and are made available to the Purchaser's inspector upon request.

Furnace sensitized stainless steels are excluded from use in the reactor coolant pressure boundary through selection of materials, control of welding and heat treating procedures and development of fabrication techniques and sequences that require welding of 300 series stainless steel safe ends after final stress relief of the major assembly.

The major portions of the reactor coolant pressure boundary materials are carbon steel and nickel-chromium-iron alloy. These materials are not subject to furnace sensitization.

Carbon steel pressure boundary surfaces are clad with either stainless steel or nickel-chromium-iron alloy as shown in Table 5.2-4 to provide a corrosion resistant barrier for the reactor coolant. Stainless steel cladding on the reactor vessel and pressurizer consists of Type 308 weld deposited metal. Stainless steel cladding on the primary side of the replacement steam generator consists of Type 308L weld deposited metal. Weld metal composition is controlled to overcome interface dilution and to provide an austenitic ferritic structure. During stress relief of the component at 1150 ± 25°F, the delta ferrite acts as a carbon sink and prevents formation of a continuous network of chromium carbide precipitates in the Type 308 cladding. The cladding of the reactor coolant piping is mill clad low carbon Type 304L stainless steel which is not susceptible to the formation of continuous chromium carbide grain boundary networks.

Some carbide precipitation will occur as a result of welding annealed stainless steel piping such as the pressurizer surge line, charging lines, spray and safety injection lines. Metallographic examination of such welds and heat affected zones reveals that only discontinuous grain boundary precipitates are present.

5.2.3.7 Cleaning and Contamination Protection Procedures

Specific requirements for cleanliness and contamination protection are included in the equipment specifications for components fabricated of austenitic stainless steel. The provisions described below indicate the type of procedures utilized for components to provide contamination control during fabrication, shipment and storage.

Contamination of austenitic stainless steels of the 300 type by compounds which can alter the physical or metallurgical structure and/or properties of the material was avoided during all stages of fabrication. Painting of 300 series stainless steels was prohibited, except for halide free silicone coating. Grinding was accomplished with resin or rubber bonded aluminum oxide or silicone carbide wheels which were not previously used on materials other than 300 series stainless alloys.

Internal surfaces of completed components were cleaned to produce an item which was clean to the extent that grit, scale, corrosion products, grease, oil, wax gum, adhered or embedded dirt or extraneous material were not visible to the unaided eye. Cleaning was affected by either solvents (acetone or isopropyl alcohol) or inhibited water (30-200 ppm hydrazine). Cleaning water conformed to the following requirements:

| | |
|---|---|
| Chloride, PPM | < 0.60; |
| Fluoride, PPM | < 0.40; |
| Conductivity, umhos/cm | < 5.0; |
| pH | 6.0-8.0; and |
| Visual clarity | No turbidity, oil or sediment. |

For the replacement steam generators, water used for hydrostatic tests and equipment flushes met the following requirements as required by the Certified Design Specification:

| | |
|---|---|
| Sodium ion | 0.05 ppm, max. |
| Chloride ion | 0.05 ppm, max. |
| Fluoride ion | 0.05 ppm, max. |
| Sulphate ion | 0.05 ppm, max. |
| Conductivity | 2.0 micro Siemens/CM, max. |
| pH | 6.0 to 8.0 (Primary)/9.8 - 10.5 (Secondary) |
| Clarity | No Turbidity, Oil or Sediment |

Finished stainless steel pipe spools were cleaned and pickled in accordance with ASTM A-380, "Descaling and Cleaning Stainless Steel Surfaces," and as a final cleaning procedure underwent passivation. When the cleaned surfaces were suitably dry, they were painted immediately with a halide free silicone coating. All materials used in cleaning were not to have halide ions in excess of 20 ppm.

Prior to shipment, components were packaged in such a manner that they would be protected from the weather, dirt, wind, water spray and any other extraneous environmental conditions which may have be encountered during shipment and subsequent site storage. The shipment package was employed for site storage and was not removed until the installation.

During fitting up and in final installation, all supports coming into contact with stainless steel components were stainless steel or halogen free plastic. Materials used in the final insulation of stainless piping underwent strict QC control, assuring their freedom from corrosion inducing contaminents.

Onsite inspectors assured the above required procedures were complied with.

The RPZR meets, at minimum, Regulatory Guide 1.37 and ANSI Standard N45.2.1-1980, with internal and external shell cleanliness maintained at ANSI levels B and C, respectively.

To prevent halide-induced, intergranular corrosion which could occur in an aqueous environment with significant quantities of dissolved oxygen, flushing and hydrotest water were inhibited via additions of hydrazine. Many experiments conducted by Combustion Engineering have proven this inhibitor to be completely effective. Operational chemistry specifications preclude halides and oxygen, both prerequisites for intergranular cracking and are shown in Table 9.3-8.

Zinc injection has been added to maintain a concentration of depleted zinc in the reactor coolant between 5 and 10 ppb. The depleted zinc in the reactor coolant is used primarily as a means to reduce radiation dose rates, but it also will mitigate the occurrence or severity of primary water stress corrosion cracking of Alloy 600.

REFERENCES FOR SECTION 5.2.3

1) FPL Letter, L-93-286, "St. Lucie Units 1 & 2, Generic Letter 92-01 Rev. 1 Response to RAI," D. A. Sager to USNRC, November 15, 1993.

## 5.2.4 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS

### 5.2.4.1 Design Bases

The reactor coolant pressure boundary leakage detection systems are designed to detect and identify abnormal leakage within the limits given in the Technical Specifications.

The leakage detection system is capable of reliably:

a) detecting unidentified sources of abnormal leakage as low as 1.0 gpm; and

b) identifying particular sources of abnormal leakage as low as 1.0 gpm.

The criteria for reactor shutdown, if either the total identified or unidentified leakage rate is exceeded, are discussed in the plant Technical Specifications.

The leakage detection systems meet the intent of Regulatory Guide (RG) 1.45. The NRC has accepted the use of the containment radiation monitoring systems with respect to leak-before-break and RG 1.45. (See References 5 and 8).

### 5.2.4.2 Normal Leakage

The normal total unidentified reactor coolant system leakage is approximately 0.4 gpm. This is based on operating experience.

### 5.2.4.3 Abnormal Leakage Sources

Abnormal leakage from the reactor coolant pressure boundary can occur through any of the following components:

a) pressurizer relief and safety valves

b) safety injection tank check valves

c) letdown heat exchanger tubing

d) steam generator tubing

e) reactor vessel head closure

f) valve gaskets and packing

g) reactor coolant pump flange closure

h) reactor coolant pump seal

i) other unidentified leaks

j) safety injection system pressure isolation check valves

k) reactor coolant gas vent system.

#### 5.2.4.4 Leakage From Through Wall Cracks

There is no practical analytical method available by which a leak rate can be correlated with crack size. Use of mathematical models to relate reactor coolant leakage to crack size requires assumptions regarding crack geometry and the number of leak sources. If it is assumed that the total leakage is from a single source, and that the crack can be treated, for example, as a square edged orifice, then the methods of references (1) and (2) would show that a through wall crack having an equivalent diameter of approximately 0.04 to 0.05 inch would result in a 1 gpm leak rate at operating pressure which is the maximum allowable leakage rate from unidentified sources.

For reactor coolant piping, the material defect acceptance criteria per NB-2532.1, Section III of the ASME Code, permits an indication of up to three inches. It is thus conceivable that a crack up to three inches in length could exist beneath such a laminar condition and remain undetected.

By the methods of fracture mechanics it can be shown that a through wall crack three inches in length would be approximately 12 percent of the critical crack length for an axial crack and about eight percent of the critical crack length for a circumferential crack.

#### 5.2.4.5 Leakage Detection Instrumentation

The means provided for leak detection consists of instrumentation which can detect general leakage from the reactor pressure boundary. Through changes in liquid level, flow rate or radioactivity level, specific sources of leakage can frequently be identified. The time that a 1.0 gpm reactor coolant boundary leak takes to cause a 10 percent deviation in the normal readings of the various monitoring systems is listed in Table 5.2-11. The rate of change of various leak detection parameters is also given in this table. In the case of direct leakage measurement (U:A), measurement of containment airborne concentrations of noble gases and Rb-88, normal readings and the time rate of change of said concentrations are a function of time since that last purge cycle, thermal power & leakage rate. Insofar as containment concentrations are dependent on the above parameters, data listed in Table 5.2-11 (average rate of change and elapsed time for 10% indicator increase) is based on initial time rate of change of concentration from a postulated step increase of 1.0 gpm direct reactor coolant leakage.

a) Makeup Flow Rate

An important means of detecting abnormal leakage from the reactor coolant system is through measurement of the net amount of makeup flow to the system. Since all normal sources of outflow from the system such as letdown flow and coolant pump controlled bleedoff are collected and recycled back into the coolant system by the chemical and volume control system described in Section 9.3.4 the net inventory in the reactor coolant system and chemical and volume control system under normal operating conditions will be constant. Transient changes in letdown flow rate or reactor coolant system inventory can be accommodated by changes in the volume control tank level. The net makeup to the system under zero leakage steady state conditions should be essentially zero. The makeup flow rates from the makeup water system and boric acid makeup tanks are continuously monitored and recorded. Analysis of the makeup flow record over a period of steady state operation can provide detection of abnormal leakage. Any increasing trend in the amount of makeup required indicates a leak which is increasing in rate. Suddenly occurring leaks are indicated by a step increase in the amount of makeup which does not decrease as would be the case for a purely transient condition.

The maximum capacity of the reactor coolant makeup system is 132 gpm (three 44 gpm charging pumps) which is much greater than the maximum allowable Technical Specification leakage.

b) <u>Leakage Within Containment</u>

Reactor coolant system leakage within the containment can be detected by the following methods:

1) Reactor cavity containment sump level - Collection of water in the reactor cavity containment sump indicates possible reactor coolant leakage. Reactor building floor drains and containment fan cooling unit condensate drains are routed to the sump so that water does not accumulate in areas of the containment other than the sump.

   All drains entering the sump are routed first to a measurement tank. A triangular notch weir is machined on the side of the measurement tank. The flow through the weir causes the level of the measurement tank to correspond to the flow of water into the tank. A seismically qualified level switch actuates an alarm in the control room when the water level corresponding to 1 gpm or more into the tank is reached. A non-seismic level detector with a recorder in the control room will be used to monitor the actual flow through the weir. The recorder will have a full scale range of 0 to 12 gpm. In addition, the recorder initiates a reactor cavity high leakage annunciator in the control room as a backup for the level switch alarm.

2) Containment Radiation - Containment radiation level due to direct reactor coolant system leakage is continuously indicated in the control room by the containment atmosphere radiation monitoring system described in Section 12.2.4.1. This system takes a sample of air from the containment cooling system ductwork and monitors it for radionuclide concentration in both gaseous and particulate form.

High level and alert status alarms are located in the control room. Listings of time rate-of-change in noble gas and Cs-137 concentration and time for 10 percent deviation from normal, in Table 5.2-11 based on a postulated step increase in direct leakage from 0.1 gpm to 1 gpm at 85 percent thermal rating, 0.1 percent failed fuel, at the end of a 90 day purge cycle before airborne clean-up units are operational. The response times indicated represent the worst case. As noted, the data provided in Table 5.2-11 is based on operation with design basis failed fuel. Since improved fuel designs have resulted in lower reactor coolant activity levels, the containment airborne radiation monitor alarm setpoints may be set at 2 times background per the Reference 7 safety evaluation.

c) Relief and Safety Valve Leakage

Leakage through the pressurizer relief valves and safety valves is detected by an increasing temperature in the valve discharge line (Figure 5.1-3) and/or rising water level in the pressurizer quench tank. These parameters are monitored as follows:

1) Discharge Line Temperature - Each of the pressurizer safety valve discharge lines contain a temperature detector (TE-1107, 1108, 1109) for monitoring valve leakage. The common discharge line from the power relief valves also contains a temperature detector (TE-1106). Control room temperature monitoring instrumentation consist of indicator/alarm units (TIA-1107, 1108, 1109 and 1106) for each of these detectors. Small amounts of safety or relief valve leakage will produce a rapidly increasing temperature indication since the discharge piping has a relatively small volume.

2) Acoustic Monitor – Each pressurizer safety and PORV discharge line contains an accelerometer used for detection of flow noise through the valve. The noise signal is converted to a voltage proportional to the flow detected and indicated in the control room. A common control room annunciator will alarm beyond a specific threshold. The control room operator will confirm the alarm by checking the individual monitors.

3) Quench Tank Water Level - Since the safety and relief valves discharge to the pressurizer quench tank steam leaking through the valves will eventually condense in the quench tank and cause increasing water level and temperature. Level indicator alarm unit LIA-1116 detects this increasing water level change and TIA-1116 detects corresponding increase in water temperature due to steam entry into the tank.

d) Safety Injection Tank Check Valve Leakage

Leakage of reactor coolant through the safety injection tank check valves (V3215, 3225, 3235, 3245) shown on Figure 6.3-2 can be detected by:

1) Safety Injection Tank Water Level - In leakage of reactor coolant to the safety injection tank produces a rising water level in the tank. This is detected by the tank level indicator/alarm (LIA-3311, 3321, 3331, 3341) units annunciated in the control room as well as by the tank mounted level switches (LS-3313, 3323, 3333, 3343) which actuate high water level alarms.

2) Safety Injection Tank Pressure - Since the safety injection tank is a relatively small closed volume with a nitrogen cover gas, the rising water level due to reactor coolant inflow is accompanied by an increasing tank pressure. Pressure

Indicator alarm units (PIA-3311, 3321, 3331 and 3341) on the control board monitor the tank pressure and annunciate alarms on high tank pressure as well as pressure switches PS-3313, 3323, 3333 and 3343 which also actuate a high pressure alarm.

The Safety Injection Tank Check Valves are within the scope of Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves." SIT pressures and levels are continuously monitored and alarmed. These instrumentation and alarms indicate possible check valve leakage, if it were to occur.

e) Heat Exchanger Leakage

Leakage of reactor coolant through the letdown, reactor coolant pump seals and sample heat exchangers can be detected by any combination of the following:

1) Component cooling water system activity – Primary system heat exchanger leaks will produce in-leakage of reactor coolant and fission products into the component cooling water system. Such in-leakage increases the normally low radiation levels in the system and can be detected by the radiation monitors (RE-26-56 and RE-26-57). These are off line monitors. Flow is caused by the differential pressure between the heat exchanger outlet and the pump suction. A recorder and high radiation alarm are provided in the control room.

   Complete dispersion of only one gallon of primary coolant throughout the volume (80,000 gal) of the component cooling water system is sufficient to cause a rapid change in detector scale of 10 percent. The limit on detection is the transport time around the component cooling water system loop. The longest time a volume of coolant leakage would have to travel before reaching the detector is 3.5 minutes. The detection time is based on component cooling water radiation being directly proportional to the product of percent failed fuel and leak rate.

2) Component cooling water surge tank level - In-leakage of reactor coolant increases the inventory in the component cooling system, causing a rising surge tank level. Level Switches LS-14-1A and B, LS-14-5 and local gage glasses (LG-14-2A, LG-14-2B) mounted on the surge tanks provide control room high and low water level alarms and local indication of tank water level.

3) Component cooling water system isotopic analysis - The component cooling water system is routinely sampled for gross beta-gamma activity. This analysis provides a diverse and redundant method for detecting reactor coolant leakage into the component cooling water system.

f) Steam Generator Tube Leakage

Leakage of reactor coolant through the steam generator tubing is indicated by increasing secondary side radioactivity due to the buildup of fission products contained in the reactor coolant.

The following are methods for detecting the resulting radiation levels.

1) Blowdown line radiation - Increasing radiation levels due to dissolved and entrained fission products in the secondary side water can be detected by the radiation monitors in each of the steam generator blowdown sample lines. Remote readout and high radiation alarms are provided.

2) Off gas radiation due to gaseous and volatile fission products in the main steam system will be detected by the radiation monitor in the condenser off gas stream. This monitor is provided with remote readout and high radiation alarm.

3) Main steam radiation monitors will detect increasing levels of radiation due to gaseous and volatile fission products in the main steam system. These monitors provide remote readout and high radiation alarm.

g) Reactor Vessel Head Closure Leakage

The space between the double O-ring seal is monitored by a local pressure gage (PI-1118) and pressure switch (PS-1118) to detect an increase in pressure which indicates a leak past the inner O-ring. A high-pressure alarm actuated by pressure switch PS-1118 alerts the operator to the presence of leakage past the inner seal.

h) Reactor Coolant Pump Closure Leakage

This system is essentially the same as the one for the reactor vessel head closure. The local indicators (PI-1150, 1160, 1170 and 1180) and pressure switches (PS-1150, 1160, 1170 and, 1180) provide the leak detection monitoring system with control room annunciation via the annunciator window and a Distributed Control System (DCS) driven flat panel display for the reactor coolant pump closures.

i) Reactor Coolant Pump Seals

Instrumentation detects abnormal seal operation. The reactor coolant pumps are equipped with three stages of seals plus a vapor backup seal as described in Section 5.5.5. During operation the reactor coolant system operating pressure is decreased through the three seals to approximately volume control tank pressure. The vapor seal prevents leakage to the containment atmosphere and allows sufficient pressure to be maintained to direct the controlled seal leakage to the volume control tank. The vapor seal is designed to withstand full reactor coolant system pressure in the event of failure of any or all of the three primary seals.

Referring to Figure 5.5-7, the reactor coolant pump flow diagram, the following conditions are postulated to exist prior to the unlikely event of a vapor seal failure:

1) the lower, middle and upper seals fail;
2) the excess flow check valve closes:
3) the reactor coolant pump is stopped; and
4) the pressure of the vapor seal is reactor coolant system pressure, i.e., approximately 2235 psig.

In the event of vapor seal leakage for the conditions prescribed, the flow through the vapor seal results in decreasing differential pressures throughout the seal chambers as evidenced by the pump seal pressure instrumentation in the control room. The seal temperature instrumentation also gives indication of a faulty vapor seal by the increased temperatures caused by increased leakage. Further indication of vapor seal leakage is provided by the reactor cavity sump instrumentation. Seal leakage will also be indicated by increased temperature downstream of the seal heat exchanger. There will be annunciation (alarm) in the control room via the annunciator window and a DCS driven flat panel display located on RTGB-103 and isolation of the CCW piping around the seal heat exchanger. The isolated portion has a safety relief which relieves to the reactor cavity sump. The DCS was expanded to include the reactor coolant pump monitoring and display system. A more detailed discussion of the DCS can be found in Subsection 7.5.1.3.1. The flat panel display was installed to integrate the RCP monitoring and display system into the DCS in addition to the equipment discussed in Subsection 7.5.1.3.1.

j) Safety Injection System Pressure Isolation Check Valves

Leakage of reactor coolant through the safety injection system isolation check valves (V3217, V3227, V3237 and V3247) shown on Figure 6.3-2 can be detected by an associated pressure increase on the low pressure side of the check valves. Pressure indicator alarm instruments (PIA-3319, 3329, 3339 and 3349) on the control board monitor system pressure and annunciates alarms on high system pressure. Safety injection system isolation check valves outside the containment (V3113, V3114, V3123, V3124, V3133, V3134, V3143 and V3144) shown on Figure 6.3-2 are also periodically tested in accordance with the Plant Technical Specifications, in order to reduce the probability of an intersystem LOCA in the high-and-low pressure safety Injection system pipe lines. These valves are also within the scope of Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves." (See Table 5.2-12.)

k) Reactor Coolant Gas Vent System Leakage

Detection of leakage through one of the primary RCGVS valves (V1441, V1442, V1443 and V1444 as shown on Figure 5.1-3) is accomplished through the use of a pressure indicator (PI-1117) mounted in the control room, which will show high pressure, thus indicating leakage.

l) Shutdown Cooling Isolation and Check Valves

Certain Shutdown Cooling Valves as identified in Table 5.2-12 are within the scope of Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves." The test frequency and leakage limits of the LPSI header check valves are provided in the Unit 1 Technical Specifications. Shutdown cooling isolation valves are tested for leakage in accordance with plant procedures (Ref. 6).

#### 5.2.4.6 System Evaluation

The instrumentation provided for reactor coolant system leak detection is capable of detecting leakage as low as 1.0 gpm. This assures that unidentified reactor coolant system leakage can remain within the allowable limits as specified in the Technical Specifications.

Table 5.2-11 shows the sensitivity of the various leak detection instrumentation for a 1.0 gpm leak rate. The rate of change of indication of the various parameters provides the necessary information to identify and estimate reactor coolant system leakage rates for a 1.0 gpm leak. A 10 percent change from normal readings will be produced within 24 hours for a 1.0 gpm leak rate. For higher leak rates, the rate of change of indication will be increased and the time to produce alarm will be reduced linearly except for direct airborne leakage in which case radionuclide concentration in both the gaseous and particulate forms will be monitored by the containment radiation monitoring system described in Section 12.2.4.1.

The values given in Table 5.2-11 are calculated using conditions expected to exist during normal operation. Changes in radiation levels in the containment, component cooling water system and secondary system are calculated assuming reactor coolant activity based on 0.1 percent failed fuel.

Changes in safety injection tank, component cooling surge tank and quench tank water levels and pressure are calculated assuming direct liquid leakage into the tanks.

5.2.4.7 Testing and Inspection

Preoperational testing consists of calibrating the instruments, testing the automatic controls for activation at the proper set points and checking the operability and limits of alarm functions. Radiation detectors can be remotely checked against a standard source during normal operation.

Normal leakage rates will be identified at the early stages of plant operation by the makeup water data. The normal operating levels will be compared with the identified leakage and used to verify the sensitivity of the instrumentation.

5.2.4.8 Leakage Checks During Shutdown

Leakage of reactor coolant is checked during shutdowns in the following manner:

a) Prior to reactor startup following each refueling outage, pressure retaining components of the reactor coolant pressure boundary will be visually examined for evidence of reactor coolant leakage while the system is under a test pressure of not less than the nominal system operating pressure at rated power.

b) The visual examinations above will be conducted in conformance with the procedures of Section XI of the ASME Boiler and Pressure Vessel Code 1989 Edition subject to modifications established by 10 CFR 50.55a.

   The source of any reactor coolant leakage detected by the examinations of (a) above will be located and evaluated for corrective measures as described in the ASME Code, 1989 Edition subject to modifications established by 10 CFR 50.55a.

c) Prior to entering Mode 2 after refueling, returning valves to service following maintenance or as otherwise outlined in the Technical Specifications, each safety injection system isolation valve identified in Section 5.2.4.5j) is tested to insure leak tightness within the allowable leakage limits.

5.2.4.9 Criteria for Reactor Shutdown Leakage Basis

The maximum allowable leakage rate from unidentified sources is limited to 1 gpm as specified in the Technical Specifications. The basis for the proposed 1 gpm leakage rate from unidentified sources in the reactor coolant pressure boundary is that this rate can be reasonably detected within a reasonable time period and appropriate action taken to minimize the potential for propagation to a gross failure.

The maximum allowable total leakage rate for an identified and evaluated leak is limited to 10 gpm as specified in the Technical Specifications. This is well within the 44 gpm capacity of one charging pump. The 10 gpm leakage rate is based upon the ability of one charging pump to makeup reactor coolant leakage and still maintain a reasonable makeup margin (30 gpm) such that repairs may be effected without the necessity for shutdown.

The maximum allowable intersystem leakage of each safety injection system isolation check valve is 5 gpm. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are unacceptable if the latest measured rate exceeds the rate determined by the previous test by an amount that reduces the margin between the measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

REFERENCES FOR SECTION 5.2.4


1) Flow of Fluids, Technical Paper No. 410, Crane Co. 1957.

2) The Discharge of Saturated Water Through Tubes, H. K. Fauske, Chemical Engineering Progress Symposium Series, Heat Transfer Cleveland, No. 59, Vol. 61.

3) Program Containair 2500, "Effect of Air Clean-Up Systems on Airborne Radioactivity," Ebasco Services, March 1973.

4) DELETED

5) JPN-PSL-SENP-92-044, Documentation of Consistency with Regulatory Guide 1.45 for Adaptation of Leak-Before-Break Methodology, Revision 0.

6) C. O. Woody (FPL) to NRC Document Control Desk, "Generic Letter 87-06, Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," letter L-87-223, June 10, 1987.

7) Safety Evaluation PSL-ENG-SENS-97-087, Revision 0.

8) Safety Assessment by Plant Systems Branch Division of Systems Safety and Analysis Office of Nuclear Reactor Regulation Region II Concerns (TIA 96-019) Regarding the Containment Radiation Monitoring Systems at St. Lucie Units 1 and 2 and Turkey Point Units 3 and 4, May 27, 1999.

## 5.2.5 INSERVICE INSPECTION

Provisions are made in the plant design for access to permit the conduct of preoperational and inservice inspections as specified in the ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems. The design and arrangement of the components are such that space is provided to conduct examinations either from the interior or the exterior or a combination of both. The inservice inspection program shall be updated periodicall to meet the 10 CFR 50.55a requirements.

Note: The replacement steam generators (RSGs) are designed to minimize the time required for ISI. The RSGs comply with the ISI requirements specified by the ASME Boiler and Pressure Code, Section XI, 1986 Edition, No Addenda.

The areas selected for inspection represent those with high service factors and random areas which represent the general overall condition of the reactor coolant system. The NRC approved ISI program is referenced in the facilities Technical Specifications.

The use of conventional nondestructive, and visual test techniques, both direct and remote, can be applied to the reactor coolant system components. The high radiation levels and remote underwater accessibility of the reactor vessel present special problems. In order to facilitate an inservice inspection of the vessel from the internal surfaces during refueling, the vessel internals and the core barrel are removable. During refueling, the reactor vessel head, closure seal surfaces and studs may be examined. This allows the internal parts of the vessel which are visible, including the cladding and components, to be visually examined, as well as allowing access to the vessel wall for volumetric examinations.

The design considerations which have been incorporated into the system and plant layout to permit the required examinations are as follows:

a) Storage space is provided for the reactor vessel internals and core barrel in the refueling cavity, which will permit internal and external examinations of these components.

b) The reactor vessel head is stored dry on the containment operating floor during refueling to facilitate direct visual inspection.

c) Reactor vessel studs, nuts and washers can be removed to dry storage during refueling.

d) Limited clearance is provided around the reactor coolant piping penetrating the primary shield which permits access to at least one of the reactor vessel cold leg nozzle welds.

e) Limited access is provided to the external surface of the reactor vessel lower head through the reactor cavity drain tunnel.

f) The reactor coolant pumps can be disassembled and inspected internally.

g) Insulation on reactor coolant system components and piping is removable where necessary.

h) Portions of the auxiliary systems piping, and emergency core cooling system piping are arranged for maximum accessibility inside the containment. Access is not available to the segments of these systems where the piping penetrates the reactor coolant system missile shield wall or within the containment type 1 penetrations. The containment type 1 penetrations will be able to withstand the jet forces associated with the flow from a postulated rupture of the pipe in the penetration or adjacent to it, while still maintaining the integrity of containment.

i) Portions of the auxiliary system piping and emergency core cooling piping external to the containment are accessible for inspection at any time except where the piping penetrates the concrete floors and walls.

j) The piping supports and restraints will be designed to facilitate accessibility for examination to the maximum practicable extent commensurate with other design requirements. Certain welds in pipe restraint structures will not be available for inspection after installation. An example of this inaccessibility is the welds attaching shear keys to the base or anchor plates. The shear keys will be embedded in cement grout during installation and are therefore inaccessible for visual examination.

k) The Replacement RVCH is designed to minimize the time required for ISI. The one piece forging has eliminated all of the full penetration joining welds in the head and the flange. The CEDM nozzles and the thermal sleeves have been designed to allow full access for VT inspection of the attaching weld.

The inservice inspection schedule is based on a ten year interval as required by the ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems and is defined in the inservice inspection program. The system boundary subject to inspection is defined in Regulatory Guide 1.26. Alternatives to specific code requirements have been included in relief requests or incorporated in ASME Code Cases. A list of these documents is provided in the inservice inspection program.

Reactor coolant system pressure boundary valves were hydrostatically tested in accordance with Pump and Valve Code requirements. Main seats, back seats, and packing were hydrostatically leak tested at pressures defined by MSS standard SP-61. Permissible seat leakage was limited to 10 cc/hr/inch of seat diameter. No visible packing leakage was permitted. Minimum wall thickness measurements were made to verify adequacy for the operating service condition. Safety valves were seat leak tested with steam at a pressure corresponding to at least 92% of the set pressure with no visible or audible leakage permitted. Valve seat leakage tests were also conducted using air at 90% of set pressure with a maximum allowable leakage rate of 10 bubbles per minute. Set pressure and blowdown were verified with steam using a prorated spring. Final set pressure was established using air. Valves were also hydrostatically tested in accordance with Pump and Valve Code requirements. Safety and relief valves are flanged and can be removed from the system for disassembly and internal inspection. Motor and pneumatic operated valves were cycled at least five times by the operator and once manually to assure proper operation.

All pressure isolation valves (PIVs), with the exception of the shutdown cooling (SDC) return isolation valves and the safety injection tank (SIT) discharge check valves, are tested in accordance with the Technical Specifications, which specify the test frequency and leakage limits for the PIVs (see Table 5.2-12). The SDC return isolation valves and the SIT discharge check valves are not required to be tested for leakage by the Technical Specifications. They are, however, tested for leakage in accordance with plant procedures or are continuously monitored for indication of leakage by installed plant instrumentation, as described below.

The SDC return isolation valves are tested for a leakage rate in excess of 1 gpm using indication of pressure increase in isolated downstream piping with a pressure differential of greater than 200 psid. If a leakage rate of greater than 1 gpm is indicated, a volumetric leakage test is conducted and verified to be less than, or equal to, half the margin between the previously measured leakage rate and the maximum permissible leakage rate of 5 gpm. The SDC return isolation valves are tested on the same frequency as required for other PIVs by the Technical Specifications.

The SIT discharge check valves isolate the SIT from the SI header when SI header pressure is greater than SIT pressure. SIT pressures and levels are continuously monitored and alarmed. These instruments/alarms would indicate possible check valve leakage, if it were to occur.

#### 5.2.5.1 Inspection Equipment

Florida Power and Light plans to retain a qualified organization to perform periodic inservice inspections of Code Class 1, 2 and 3 components. The equipment to be utilized will reflect the state of the art. The detailed inservice inspection program is referenced in the plant Technical Specifications. The selection of inspection techniques is based in large part on the guidance provided by Section XI.

### 5.2.5.2 Loose Parts Monitoring System

#### 5.2.5.2.1 Design Bases

St. Lucie Unit 1 is provided with a loose parts monitoring system (LPMS) that is permanently installed to provide the in-service monitoring function during plant operation.

The LPMS monitors the reactor coolant system (RCS) for internal loose parts. The system is designed to detect a loose part striking the internal surface of RCS components with an energy level of one-half foot pound or more within 3 feet of one of the eight sensors.

#### 5.2.5.2.2 Design and Operation

The LPMS consists of transducers, preamplifiers, a computer and a flat panel display to automatically detect and record metal to metal contact within the RCS.

Eight high temperature rated, piezoelectric accelerometers are installed externally on the Reactor Coolant System:

a) Two at each steam generator

b) Two at the head of the reactor vessel

c) Two at the bottom of the reactor vessel

The accelerometer signals are individually processed within the containment for wire transmission to an alarm and recording console located in the control instrumentation area. When a loose part is detected, the data acquisition system automatically activates an audible as well as visual alarm to alert the control room operator. Alarm indication for each accelerometer, and simultaneous recording of signals from all accelerometers is provided at the console. All channels can be recorded and compared to historical data.

Additionally, an alarm indication of a loose part or critical-failure of the system at the loose parts monitor console is also indicated on a control room annunciator. The system will activate the annunciator alarm channel whenever a critical failure or loose part is detected.

#### 5.2.5.2.3 Discussion of LPMS Detection Capabilities

St. Lucie Unit 1 is not committed to Regulatory Guide 1.133 Revision 1 although the installed system meets the requirements of the Regulatory Guide. The following is a discussion of system operation and the capabilities of the system in terms of the Regulatory Guide.

The LPMS is able to detect a metallic loose part that weighs from 0.25 lb to 30 lb and impact with the kinetic energy of 0.5 ft-lb on the inside surface of the reactor coolant pressure boundary within 3 feet of a sensor. Additionally, the system employs High Pass Filters, Low Pass Filters and Software Algorithms to filter out non metal to metal impacts to minimize the alarms from vibrations that are not loose parts.

Each sensor provides a signal to a charge amp located outside the Bio-Shield. Outputs from the two charge amps are transmitted through one cable to the LPMS Cabinet. Separation is needed only to a point that is accessible during full power operation which is maintained from the preamp to the sensors.

The LPMS has both an automatic and manual startup of data acquisition equipment. When a loose part is detected, the data acquisition system automatically activates an audible as well as visual alarm to alert the control room operator. This system also provides for recording of all sensor signal waveforms in digital form. Upon alarm, the system defaults to recording all channels as well as displaying the alarming channel and the three nearest sensors. The system is capable of immediate visual and audio monitoring of all signals.

The LPMS system provides an alarm for a loose part and alert level for any noise or adverse system condition that is not a loose part. The capability of the system exceeds the Regulatory Guide requirements by using alternate means of loose parts determination. All channels can be recorded and compared to historical data using the Waveform Software.

Test signals are provided to the transducer (AST) and preamp (PST) to initiate an alarm condition, for troubleshooting and checking operation of the system to the maximum extent practicable.

The portion of the system located inside the containment is designed for high temperature and humidity, is resistant to the effects of radiation and will function after a design basis earthquake. The processor is a heavy duty, industrial chassis built to withstand vibration and the environment of the Control Room.

The components supplied with the LPMS are of the highest quality available.

Self diagnostics that are a design feature of the LPMS assist in finding problems quickly. Access to the control room equipment is from the rear of the cabinet and any component can be repaired or replaced easily with plug in cables and rack style screw mounting. There are two sensors in each location. One sensor is a backup for more reliable system operation since there is no access to the sensors during operation. The pre-amps are located outside the bio shield which allows access under some at power conditions.

TABLE 5.2-1

REACTOR COOLANT SYSTEM PRESSURE BOUNDARY CODE REQUIREMENTS

| Component | Codes and Classes |
|---|---|
| * Reactor Vessel (P.O. date April 25, 1968) | ASME Section III, Nuclear Vessels, Class A, 1965 Edition through Winter 1967 Addenda |
| Original Pressurizer (P.O. date June 20, 1968) | |
| Pressurizer Heaters (P.O. date March 18, 1997) | ASME Section III Nuclear Power Plant Components, Class I, 1986 Edition with No Addenda |
| Reactor Coolant Pump (P.O. date October 3, 1968) | ASME Section III Nuclear Vessels, Class A, 1965 Edition through Winter 1967 Addenda |
| Quench Tank (P.O. date April 28, 1968) | ASME Section III, Class C, through Winter 1969 Addenda |
| Pressurizer Safety Relief Valves & Lines Valves (P.O. dates from July 24, 1970 to Nov. 20, 1970) | ASME Code for Pumps and Valves for Nuclear Power Class I, Nov. 1968 Draft |
| Piping and Nozzles (P.O. date August 15, 1968) | ANSI B31.7, Code for Nuclear Power Piping, Class I, Feb. 1, 1968 Draft Edition for Trial Use and Comment |
| CEDM | ASME Section III, 1998 Edition through 2000 Addenda |
| Replacement Steam Generators (P.O. date June 16, 1992) | ASME Section III, 1986 No Addenda |
| * Replacement RV Closure Head | ASME Section III, 1989 Edition, No Addenda |
| RVLMS Pressure Housing | ASME Section III, 1998 Edition through 2000 Addenda |
| ICI Nozzle Adapter | ASME Section III, 1989 Edition, No Addenda |
| Replacement Pressurizer | ASME Section III, 1998 Edition through 2000 Addenda |
| Replacement Pressurizer Heaters | ASME Section III, 1998 Edition, through 2000 Addenda |

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TABLE 5.2-1a

COMPONENT CYCLIC OR TRANSIENT LIMITS

| COMPONENT | CYCLIC OR TRANSIENT LIMITS | DESIGN CYCLE OR TRANSIENT |
|---|---|---|
| Reactor Coolant System | 40 Cycles of loss of load without immediate reactor trip | 100% to 0% RATED THERMAL POWER |
| | 40 cycles of loss of offsite A.C. electrical power | 100% to 0% RATED THERMAL POWER |
| | 400 reactor trips | 100% to 0% RATED THERMAL POWER |
| | 16 inadvertent auxiliary spray cycles | Spray line 650°F to 120°F in 1.5 seconds |
| | 200 leak tests | Pressure ≥ 2235 psig |
| | 10 hydrostatic pressure tests | Pressure ≥ 3110 psig |
| Secondary System | 5 steam line breaks | Complete loss of secondary pressure |
| | 200 leak tests | Pressure ≥ 985 psig |
| | 10 hydrostatic pressure tests | Pressure ≥ 1235 psig |

TABLE 5.2-2

LOADING COMBINATIONS AND PRIMARY STRESS LIMITS

Primary Stress Limits

| Loading Combinations | Vessels | Piping | Pumps & Valves | Supports |
|---|---|---|---|---|
| 1. Design Loading + Operating Basis Earthquake | $P_M \le S_M$<br>$P_B + P_L \le 1.5 S_M$ | $P_M \le S_M$<br>$P_B + P_L \le 1.5 S_M$ | See Note (d) | Working Stress |
| 2. Normal Operating Loadings + Design Basis Earthquake | $P_M \le S_D$<br>$P_B \le 1.5 \left[1 - \left(\frac{P_M}{S_D}\right)^2\right] S_D$<br>See Note (b) | $P_M \le S_D$<br>$P_B \le \frac{4}{\pi} S_D \; Cos\left(\frac{\pi}{2} \bullet \frac{P_M}{S_D}\right)$<br>See Note (c) | | Within Yield |
| 3. Normal Operating Loadings + Pipe Rupture + Design Basis Earthquake | $P_M \le S_L$<br>$P_B \le 1.5 \left[1 - \left(\frac{P_M}{S_L}\right)^2\right] S_L$<br>See Note (b) | $P_M \le S_L$<br>$P_B \le \frac{4}{\pi} S_L \; Cos\left(\frac{\pi}{2} \bullet \frac{P_M}{S_D}\right)$<br>See Note (a) (c) | | Deflection of supports limited to maintain supported equipment within limits shown for vessels and piping |

Notes:

a) These stress criteria are not applied to the piping run within which a pipe break is considered to have occurred.

b) For loading combinations 2 and 3, stress limits for vessels, with the symbol $P_M$ changed to $P_L$ , are used in evaluating the effects of local loads imposed on vessels and/or piping.

c) The tabulated limits for piping are based on a minimum "shape factor". These limits may be modified to incorporate the shape factor of the particular piping being analyzed.

d) The reactor coolant pump is the only Class I pump in the reactor coolant pressure boundary. The reactor coolant pumps are designed to the requirements of ASME Section III, Nuclear vessels, Class A, 1965 edition through the Winter of 1967 Addenda supplemented by the requirements given in Table 5.2-2A. For valves, the primary pressure rating $P_r$ is not exceeded for any loading combination.

TABLE 5.2-2 (Cont'd)

Legend

| | | |
|---|---|---|
| $P_M$ | = | Calculated Primary Membrane Stress |
| $P_B$ | = | Calculated Primary Bending Stress |
| $P_L$ | = | Calculated Primary Local Membrane Stress |
| $S_M$ | = | Tabulated Allowable Stress Limit at Temperature from ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1965 Edition with Addenda Through Winter 1967 or ANSI B31.7. Nuclear Power Piping |
| $S_Y$ | = | Tabulated Yield at Temperature, ASME Boiler and Pressure Vessel Code, Section III. |
| $S_D$ | = | Design Stress |
| | = | $S_Y$ (for ferritic steels) |
| | = | $1.2 S_M$ (for austenitic steels) |
| $S_L$ at | = | $S_Y + \frac{1}{3}(S_U - S_Y)$ |
| $S_U$ | = | Tensile Strength of Material at Temperature |

The following typical values are selected to illustrate the conservatism of this approach for establishing stress limits. Units are $10^3$ lbs./sq. in.

| Material | $S_Y$ (1) | $S_U$ | $S_D$ | $S_L$ |
|---|---|---|---|---|
| A-106B | 25.4 | 60.0 (2) | 25.4 | 36.9 |
| SA-533B | 41.4 | 80.0 (2) | 41.4 | 54.3 |
| 304 SS | 17.0 | 54.0 (3) | 18.35 | 29.3 |
| 316 SS | 18.5 | 58.2 (3) | 22.2 | 31.7 |

(1) From ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1965 Edition at 650 F.

(2) Minimum value at room temperature which is approximately the same

650F for ferritic materials.

(3) Estimated.

TABLE 5.2-2A
LOADING COMBINATIONS AND PRIMARY STRESS LIMITS
REACTOR COOLANT PUMPS

Supplementing the requirements of Section III of the ASME Boiler and Pressure Vessel Code, which specifies stress limits for all design and normal operating loading conditions, the reactor coolant pump case assembly shall be designed such that the calculated primary membrane stresses, $P_M$ and the calculated primary bending stresses, $P_B$, do not exceed the following limits:

$$P_M \leq S_D$$

$$P_B \leq 1.5\left[1-\left(\frac{P_M}{S_D}\right)^2\right]S_D,$$ for rectangular sections

$$P_B \leq \frac{4}{\pi} \bullet S_D \cos\left(\frac{\pi}{2} \bullet \frac{P_m}{S_d}\right)$$ for annular sections

The design stress value, $S_D$ , appearing in the above expressions, shall be as follows for the loading combinations indicated.

| | Loading Combination | Pump Casing Design Stress Value | Criteria for Design of Supports |
|---|---|---|---|
| 1. | Design Loadings + Design Earthquake | Section III, ASME B & PV Code | Section III, ASME B & PV Code |
| 2. | Normal Operating Loadings + Maximum Earthquake | $S_D = S_Y$, for ferritic steels<br>$S_D = 1.2S_M$, for austenitic steels | Stresses within Yield |
| 3. | Normal Operating Loading + Pipe Rupture + Maximum Earthquake | $S_D = S_Y + \frac{1}{3}\left(S_U - S_Y\right)$ | Deflections limited to maintain supported equipment within specified stress limits (See Note 4) |

TABLE 5.2-2A (Cont'd)

Where:

$S_M$ = Tabulated Allowable Stress Limit at Temperature, Section III, ASME Boiler and Pressure Vessel Code.

$S_Y$ = Tabulated Minimum Yield Strength at Temperature, Section III, ASME B & PV Code.

$S_U$ = Minimum Tensile Strength of Material at Temperature.

Notes:

1. The expression for the limit on $P_B$ for annular sections is based on a minimum "shape factor". This limit may be modified to incorporate the shape factor of the particular section being analyzed.

2. In evaluating the effects of local loads on the vessel, as a result of loading combinations 2 and 3, the Primary Local Membrane Stress $P_L$, shall replace $P_M$ in the expressions for stress limits.

3. The stress criteria for Loading Combination No. 3 need not be applied to the piping run within which a pipe break is considered to have occurred.

4. It is not intended that the pump supports be designed to sustain pipe rupture loads applied directly to the pumps. Suitable stops or restraints to accommodate these loads will be furnished as part of the foundation structure.

TABLE 5.2-3

ACTIVE VALVES IN THE REACTOR COOLANT SYSTEM BOUNDARY

| Line | Valve Type/Tag No. | Normal Position | Post-LOCA Position |
|---|---|---|---|
| Shutdown Cooling Suction | Motor/V3651, V3652, V3480, V3481 | Closed | Closed |
| Charging (1) | Solenoid / SE-02-1, SE-02-2 | Open | Open |
| | Check/V2432, V2433, V2435 | Open | Open/Closed |
| Letdown | Air/ V2515, V2516 | Open | Closed |
| Auxiliary | Solenoid / SE-02-3, SE-02-4 | Closed | Closed |
| Spray | Check/ V2431 | Closed | Closed |
| Pressurizer Spray (1) | Air/ PCV-1100E, PCV-1100F | Open/Closed | Closed |
| Pressurizer | Motor/ V1403, V1405 | Open | Closed |
| Relief | Solenoid/ V1402, V1404 | Closed | Closed |
| Pressurizer Safety | Spring Loaded/ V1200, V1201, V1202 | Closed | Closed |
| Safety Injection Tank | Motor/ 4 V3614, V3624, V3634, V3644 | Open | Open |
| Safety Injection Tank Recirc/Drain | Air/ HCV-3618, HCV-3628, HCV-3638, HCV-3648 | Closed | Closed |
| Safety Injection | Check/4V3217, V3227, V3237, V3247 | Closed | Open |

TABLE 5.2-3 (Cont'd)

| Line | Valve Type/Tag No. | Normal Position | Post-LOCA Position |
|---|---|---|---|
| LPSI Header | Check/ V3114, V3124, V3134, V3144 | Closed | Open |
| HPSI Header | Check/ V3113, V3123, V3133, V3143 | Closed | Open |
| SDC Return | Relief/ V3469, V3482 | Closed | Closed |

(1) Valves may be open or shut during normal operation or post-accident.

TABLE 5.2-4

MAJOR COMPONENT MATERIAL SPECIFICATIONS

Steam Generators

| | |
|---|---|
| Primary head | SA-508, Class 3 (Forging) |
| Tube Sheet | SA-508, Class 3 (Forging) |
| Tubes | NiCrFe Alloy (SB-163)<br>Code Case N-20-3 Alloy 690 |
| Shell | SA-533, Type B, Class 1 and SA-508 CL3 |
| Nozzles | SA-508 Class 3 (Forging) |
| Nozzle Extensions | SA 508 Class 1 (Forging) |

Welds

| Base Material | Weld Material |
|---|---|
| SA-533, Typ. B, Cl. I | SFA 5.23 EF2-F2;<br>SFA 5.5 E-8018-C3 |
| SA-508, Cl.3 to SA-533, Typ. B, Cl.1 | SFA 5.23 EF2-F2;<br>SFA 5.5 E-8018-C3 |
| SA-508, Cl.1 to SA-508, Cl.3 | SFA 5.5 E8018.C3 |
| Inconel Cladding | SFA 5.14 ERNiCr-3 |
| Austenitic Stainless Steel Cladding SFA 5.9 | SFA 5.9 ER308L, ER309L |

Reactor Vessel

| | |
|---|---|
| Shell | SA-533 Grade B, Class 1 Steel |
| * Forgings | SA-508 Class 2 & 1 |

Welds

| Base Material | Weld Material |
|---|---|
| SA-533 Gr. B, Cl. 1 | E-8018, C3; MIL-E-18193, B-4 |
| SA-508 Cl. 2 to SA-533 Gr. B, Cl. 1 | E-8018, C3; MIL-E-18193, B-4 |
| SA-508 Cl. 1 to SA-508, Cl. 2 | E-8018, C3 |
| Nickel-Base Overlay | ENiCrFe-3; ERNiCr-3 |

Replacement RVCH

| | |
|---|---|
| Forging | SA-508 Class 3 |
| CEDM Nozzles | NiCrFe Alloy (SB-167), Code Case N-474-2 Alloy 690 |

TABLE 5.2-4 (Cont'd)

| | |
|---|---|
| CEDM Nozzle Adapters | NiCrFe Alloy (SB-166), Code Case N-474-2 Alloy 690 |
| Instrument Nozzles | NiCrFe Alloy (SB-167), Code Case N-474-2 Alloy 690 |
| Instrument Nozzle Adaptors | SS SA-479 Type 304 |
| Vent Nozzle | NiCrFe Alloy (SB-167), Code Case N-474-2 Alloy 690 |
| Vent Pipe | SS SA-479 Type 304 |
| Cladding | SS ER308, ER309 |
| <u>Weld Metals</u> | |
| SA-508 Cl. 3 to SB-167 | ERNiCrFe-7, ENiCrFe-7 |
| SB-167 to SB-166 | ERNiCrFe-7, ENiCrFe-7 |
| SB-167 to SA-479 | ERNiCrFe-7 |

Reactor Vessel (continued)

| | |
|---|---|
| Austenitic Stainless Steel Cladding | ER308, ER309, ER312 |

Pressurizer

| | |
|---|---|
| Shell & Heads with integral nozzles | SA-508 Gr3 Cl2 |
| Nozzle safe ends | SA-182 Gr F316 |
| Partial penetration nozzles | NiCrFe Alloy SB-166 (UNS N06690) |
| Heater Sleeves | NiCrFe Alloy SB-166 (UNS N06690) |

Welds

| Base Material | Weld Material |
|---|---|
| Low alloy | E-9018-G, EG |
| Low alloy cladding | Ex-309L, Ex-308L |
| Stainless steel buttering | Ex-309L, Ex-308L |
| Stainless steel safe ends | Ex-308L |
| Alloy 690 | ERNiCrFe-7 or ENiCrFe-7 |

Reactor Coolant Piping

| | |
|---|---|
| Pipe and Elbows (30" & 42") | SA-516, Grade 70 with SA-240-304L Clad |
| Piping Safe Ends (30") & Surge Line Piping | SA-351, Gr. CF8M, ASME SA-403, WP 347, ASME SA-312, TP 347 |
| Nozzle Forgings | SA-105, Gr. 2; SA-182, Gr. FI |
| Nozzle Safe Ends | SA-351, Gr. CF8M; SA-182, Gr. F316 |
| Instrument Nozzles | NiCrFe Alloy SB-166 (UNS N06690); SA-182, Gr. F316 |

Welding Filler Metal

| Base Material | Weld Material |
|---|---|
| SA-516, Gr. 70 to SA-516, Gr. 70 | E-7018(3) |
| SA-516, Gr. 70 to SA-105, Gr. 2 | E-7018 |
| Inconel Buttering | ERNiCr-3 (Inconel 182) |
| Safe Ends | ERNiCr-3 (Inconel 182) |
| Back Cladding | 1st Layer - I-309-15(1)<br>Remainder - E-308-15(2) |
| Partial Penetration Nozzle Welds | ENiCrFe-3 (Inconel 182) or ERNiCrFe-7 |
| Field Welds | E-7018 |

Note: During replacement of the steam generators, the following welding materials were used for attachment of the RCS piping to the RSG nozzles:
(1) ER309L/E309L (2) ER308L/E308L (3) ER70S-6/E-7018

Note: During replacement of the pressurizer, the following weld materials were used for attachment of the RCS piping to the pressurizer nozzles:
(1) ER316/L (2) ER308/L
The weld material used for the attachment of the heater sleeves to the heater nozzles for the Replacement pressurizer was ERNiCrFe-7.

Note: During the PWSCC mitigation of the RCS charging, drain and spray nozzles by cut and replace, the following weld material was used for all welds from nozzle to safe-end: ER309L/E316L.

Reactor Coolant Pump

| | |
|---|---|
| Casing | ASTM A-351, Gr. CF8M |
| Casing Welds | ASTM A-371, Class ER316 |
| Field Welds | ASME SA 5.4 E-309, 308L |

**CEDM

| | |
|---|---|
| Pressure Housing | ASME SA-479 TP316, SA-213 TP316, SA-182 F348, SB-166 Alloy UNS N06690, ASME SA-182 F403 T, Code Case N-4-11, ASME SA-213 TP 316 |

RVLMS

| | |
|---|---|
| Pressure Housing | SA-479 TP316, SB-166 UNS N06690, SA-312 TP316, SA-213 TP316 |

Applicable Code Cases For Reactor Vessel, Steam Generator, Pressurizer

1332 - Requirements for Steel Forgings

1335 - Requirements for Bolting Materials

1336 - Requirements for NiCrFe Alloy

1338 - L/T Examination of Plates

1359 - L/T Examination of Forgings

1361 - Socket Welds, Section III

ASME Code Case N-432, "Repair Welding Using Automatic or Machine Gas Tungsten-Arch Welding (GTAW) Temperbead Technique Section XI, Division 1".

ASME Code Case N-474-1, "Design Stress Intensities and Minimum Yield Strength Values for Alloy 690 (UN06690) with a Minimum Yield Strength of 35ksi, Class 1 Components - Section III, Division 1".

ASME Code Case N-474, "Design Stress Intensities and Yield Strength Values for Alloy 690 with a Minimum Yield Strength of 35ksi, Class I Components, - Section III, Division 1".

For the replacement steam generators, the following Code Cases are used as permitted by NRC Regulatory guides 1.85 and 1.147:

N-20-3 SB-163 Ni-Cr-Fe Tubing (Alloys 600 and 690) and Ni-Cr Alloy 800,

N-10 Time of Examination for Class 1, 2, & 3 Section III, Division 1,

N-401 Eddy Current Examination Per Section XI, Division 1,

2143 F-Number Grouping for Ni-Cr-Fe, Classification UNS W86152 Welding Electrode Section IX,

2142 F-Number Grouping for Ni-Cr-Fe, Classification UNS N06052 Filler Metal Section IX.

For the replacement of the pressurizer instrument nozzles, the following Code Cases were used as permitted by NRC Regulatory Guides 1.85 and 1.147:

2142 F-Number Grouping for Ni-Cr-Fe, Classification UNS N06052 Filler Metal Section IX.

N-432 Repair Welding Using Automatic or Machine Gas Tungsten – Arc Welding (GTAW) Temperbead Technique, Section XI, Division 1.

N-474-1 Design Stress Intensities and Yield Strength Values for UNS N06690 with a Minimum Specified Yield Strength of 35 ksi, Class 1 Components, Section III, Division 1.

For the replacement of RCS Hot Leg instrument and sample nozzles, the following Code Cases were used as permitted by NRC Regulatory Guides 1.85 and 1.147:

2142, -1 F-Number Grouping for Ni-Cr-Fe, Classification UNS N06052 Filler Metal Section IX.

N-474-1, -2 Design Stress Intensities and Yield Strength Values for UNS N06690 with a Minimum Specified Yield Strength of 35 ksi, Class 1 Components, Section III, Division 1.

For the replacement of the pressurizer and surge line elbow ASME Boiler on Pressure Vessel Code 1998 with 2000 Addenda was used.

* For the Replacement RVCH the following Code Cases were used as permitted by Regulatory Guidelines 1.85 and 1.147:

Code Case N-474-2, Stress Intensities and yield strength values for UNS 6690 with an affirmed specified yield strength of 35 ksi, Class 1 components, Section III, Division 1.

Code Case 2142-1, F-Number Grouping for Ni-Cr-Fe classification UNS NO6052, Filled Metal Section IX.

Code Case 2143-1, F-Number Grouping for Ni-Cr-Fe classification UNS W86152, Weld Electrode Section IX.

** For the Replacement CEDM the following Code Cases were used as permitted by Regulatory Guidelines 1.85 and 1.147:

Code Case N-2 (1334-3), "Requirements for corrosion-resisting steel beam and shape, Section III, Normalized and tempered Type 403".

Code Case 2142-1, F-Number Grouping for Ni-Cr-Fe classification UNS NO6052, Filled Metal Section IX.

<u>Hot Leg Pressurizer Surge & Shutdown Cooling Nozzles Alloy 600 Mitigation</u>

- PC/M 08019, implemented during SL1-22, mitigated Pressurizer and RCS Hot Leg Nozzle Alloy 82/182 Dissimilar Metal (DM) welds with full Structural Weld Overlays (SWOL) or weld repair/replacement. The mitigation was a preemptive measure to reduce susceptibility of the nozzle to safe-end DM welds to PWSCC. The mitigative repair was accomplished in accordance with the requirements of the Fourth 10-Year ISI Interval Relief Request 2.

- PC/M 08019M applied ErNiCrFe-7A UNS N06054 Structural Weld Overlay (SWOL) material over the nozzles to safe-end welds and extending over the safe-end to pipe welds.

TABLE 5.2-4A

CHEMICAL ANALYSES OF PLATE MATERIAL IN REACTOR VESSEL BELTLINE

| | Intermediate Shell Plates | | | Lower Shell Plates | | | Surveillance Weld (1) |
|---|---|---|---|---|---|---|---|
| Code # | C-7-1 | C-7-2 | C-7-3 | C-8-1 | C-8-2 | C-8-3 | 90136 Flux 3999 |
| Element (wt %) | | | | | | | |
| Si | .17 | .20 | .20 | .17 | .17 | .19 | .20 |
| S | .013 | .010 | .012 | .010 | .010 | .010 | .012 |
| P | .004 | .004 | .004 | .006 | .006 | .004 | .013 |
| Mn | 1.28 | 1.28 | 1.33 | 1.28 | 1.29 | 1.22 | 1.02 |
| C | .24 | .23 | .21 | .28 | .22 | .22 | .12 |
| Cr | .03 | .03 | .06 | .07 | .07 | .06 | .06 |
| Ni | .64 | .64 | .58 | .56 | .57 | .58 | .07 (2) |
| Mo | .60 | .59 | .58 | .65 | .66 | .59 | .55 |
| V | .003 | .003 | .003 | .002 | .002 | .002 | .006 |
| Nb | .01 | .01 | .01 | .01 | .01 | .01 | .01 |
| B | .0003 | .0002 | .0002 | .0003 | .0003 | .0001 | .0001 |
| Co | .005 | .006 | .005 | .007 | .007 | .006 | .004 |
| Cu | .11 | .11 | .11 | .15 | .15 | .12 | .27 (2) |
| Al | .018 | .020 | .020 | .027 | .025 | .022 | .001 |
| W | .01 | .01 | .01. | .01 | .01 | .01 | .01 |
| Ti | .01 | .01 | .01 | .01 | .01 | .01 | .01 |
| As | .015 | .015 | .010 | .013 | .014 | .011 | .014 |
| Sn | .006 | .006 | .006 | .009 | .010 | .006 | .005 |
| Zr | .002 | .002 | .002 | .002 | .002 | .002 | .001 |
| $N_2$ | .006 | .007 | .007 | .008 | .009 | .006 | .008 |
| Fe | (balance) | | | | | | |

(1) Identical to intermediate to lower shell course girth weld seam 9-203.

(2) This weld chemical analysis is a single actual result from the surveillance weld except that copper and nickel values are based on the “best estimate” values for a specific weld wire heat using all industry available data. The “best estimate” values were determined in response to NRC GL 92-01, Rev. 1, Supplement 1 and were submitted to the NRC in FPL Letter L-97-223 (Reference 14 in Section 5.4).

NOTE: Letter L-77-308 is the source document for all data.

TABLE 5.2-5

MATERIALS EXPOSED TO COOLANT

| | |
|---|---|
| * Reactor | |
| Vessel Cladding | Weld Deposited Type 308 SS |
| Vessel Internals | 304 SS and NiCrFe Alloy, SB-168 |
| Fuel Cladding | Zirconium alloy |
| Pipe | |
| Instrument Nozzle Replacement with Split Nozzles | SA-516 Grade 70 Base |
| Pipe Instrument Nozzles | SB-166 UNS N06690 and UNS N06600 |
| Pipe Cladding | Austenitic Stainless Steel Type 304 L |
| Replacement Steam Generators | |
| Bottom Head Cladding | Austenitic Stainless Steel, ER308L, ER309L |
| Tube Sheet Cladding | NiCrFe Alloy, ERNiCr-3 |
| Tubes | NiCrFe Alloy, SB-163 (UNS N06690) |
| Divider Plate | SA 240 Type 304L |
| Seat Bars | SB-166 Alloy 600; SB-168 Alloy 690 |
| Nozzle Dam Rings | SB-166 Alloy 690 |
| Pumps | |
| Casing | Austenitic Stainless Steel, Grade CF8M |
| Internals | Austenitic Stainless Steel, Type 316 and Type 304 |
| Pressurizer Cladding | Weld Deposited Stainless Steel Type 308L, 309L |
| * Replacement RVCH | |
| RVCH Cladding | Austenitic Stainless Steel, ER308L, ER309L |
| CEDM Nozzles | SB-167 UNS N06690 |
| Instrument Nozzles | SB-167 UNS N06690 |
| Instrument Nozzle Adaptor | SA-479 Type 304 |
| CEDM Nozzle Adaptor | SB-166 UNS N06690 |
| Vent Nozzle | SB-167 UNS N06690 |
| Vent Pipe | SA-312 Type 316 |
| CEDM | |
| Pressure Housing | ASME SA-479 TP316, SA-213 TP316, SA-182 F348, SB-166 Alloy UNS N06690, ASTM 276 Type 403 Condition T, Code Case N-2 |
| Mechanism | Austenitic Stainless Steel Types 304, 316, 348, and CF8M<br>Martensitic Stainless Steel Types 403, 410, 440C, and 17-4 PH<br>NiCrFe Alloy 690<br>NiCrFe Alloy X-750<br>Cobalt Alloys Stellite 36 and Stellite 6B |
| Weld Metal | ERNiCrFe-7A, ER316L, and IN316L |

TABLE 5.2-5 (Cont'd)

MATERIALS EXPOSED TO COOLANT

RVLMS

| | |
|---|---|
| Pressure Housing | SA-479 TP316, SB-166 TP UNS N06990, SA-312 TP 316, SA-213 TP316 |

TABLE 5.2-6

CHARPY V-NOTCH AND DROP WEIGHT TEST VALUES - REACTOR VESSEL

| Piece No. Reference Dwg. E 233-501 | Code No. | Material | Heat No. | Vessel Location | Drop Weight Results °F | Temperature of Charpy V-Notch (°F)* @ 30ft-lb | @50ft-lb | ** Minimum Upper Shelf Cv energy for Longitudinal Direction (ft.-lb.) |
|---|---|---|---|---|---|---|---|---|
| 203-02 | C-1-1 | A508 Class 2 | 5P3135-P2773 | Vessel Flange Forging | +20 | -43 | -14 | 132 |
| 204-02 | C10-1 | A533B Class 1 | C4036-2C | Bottom Head Plate | -40 | -42 | +18 | 118 |
| 204-03-A&F | C-9-2 | A533B Class 1 | C5521-3 | Bottom Head Plate | -40 | -50 | -26 | 126 |
| 204-03-B&E | C-9-3 | A533B Class 1 | C5571-3 | Bottom Head Plate | -70 | -54 | -34 | 148 |
| 204-03-C&D | C-9-1 | A533B Class 1 | C5053-1B | Bottom Head Plate | -30 | -48 | +2 | 135 |
| 205-02-A | C-4-3 | A508 Class 2 | AV3255-9A-9423 | Inlet Nozzle Forging | 0 | -63 | -30 | 109 |
| 205-02-B | C-4-2 | A508 Class 2 | AV3251-9A-9255 | Inlet Nozzle Forging | 0 | -60 | -12 | 133 |
| 205-02-C | C-4-1 | A508 Class 2 | AV3253-9A-9256 | Inlet Nozzle Forging | +10 | -62 | -40 | 141 |
| 205-02-D | C-4-4 | A508 Class 2 | AV3254-9A-9422 | Inlet Nozzle Forging | 0 | -78 | -50 | 132 |
| 205-03-A | C-16-3 | SA508 Class 1 | AV3048-9C-1470 | Inlet Nozzle Ex. Forging | +10 | -22 | 0 | 115 |
| 205-03-B | C-16-2 | SA508 Class 1 | AV3048-9C-1469 | Inlet Nozzle Ex. Forging | +10 | -22 | 0 | 115 |
| 205-03-C | C-16-1 | SA508 Class 1 | AV3048-9C-1468 | Inlet Nozzle Ex. Forging | +10 | -22 | 0 | 115 EC291392 |
| 205-03-D | C-16-4 | SA508 Class 1 | AV3048-9C-1748 | Inlet Nozzle Ex. Forging | +10 | -22 | 0 | 115 |
| 205-06-A | C-3-1 | A508 Class 2 | 9-6643-60-5665-001 | Outlet Nozzle Forging | +10 | -50 | -32 | 114 |
| 205-06-B | C-3-2 | A508 Class 2 | 9-6643-60-5665-001 | Outlet Nozzle Forging | +20 | -22 | 0 | 108 |
| 205-07-A | C-17-1 | SA508 Class 1 | AV3046-9C-1746 | Outlet Nozzle Ex. Forging | +20 | 0 | +27 | 126 |
| 205-07-B | C-17-2 | SA508 Class 1 | AV3046-9C-1749 | Outlet Nozzle Ex. Forging | +20 | 0 | +27 | 126 EC291392 |
| 215-01-A | C-6-3 | A533B Class 1 | C5313-1 | Upper Shell Plate | -10 | 0 | +24 | 117 |
| 215-01-B | C-6-2 | A533B Class 1 | C5313-2 | Upper Shell Plate | -30 | -16 | +9 | 113 |
| 215-01-C | C-6-1 | A533B Class 1 | C4516-1 | Upper Shell Plate | +10 | 0 | +34 | 104 |
| 215-02-A | C-7-1 | A533B Class 1 | A4567-1 | Intermediate Shell Plate | 0 | -35 | +10 | 126 |
| 215-02-B | C-7-2 | A533B Class 1 | B9427-1 | Intermediate Shell Plate | -30 | -42 | +10 | 126 |
| 215-02-C | C-7-3 | A533B Class 1 | A4567-2 | Intermediate Shell Plate | -30 | -18 | +30 | 117 |
| 215-03-A | C-8-3 | A533B Class 1 | C5935-3 | Lower Shell Plate | 0 | -12 | +13 | 135 |
| 215-03-B | C-8-1 | A533B Class 1 | C5935-1 | Lower Shell Plate | -10 | -14 | +16 | 126 |
| 215-03-C | C-8-2 | A533B Class 1 | C5935-2 | Lower Shell Plate | 0 | -10 | +16 | 122 |
| (Transverse)(1) | C-8-2 | A533B Class 1 | C5935-2 | Surveillance Plate | +10 (1) | | | 103* |

* Average value from curve
** Minimum value at 100% shear
(1) Baseline Surveillance Program Dete (TR-MCM-005)

Replacement Closure Head Forging: SA-508, Class 3 Low alloy steel. From 6 Charpy Impact tests conducted at $T_{ndt}$ + 60 degrees F (20 deg F), the minimum absorbed energy was 137 ft-lbs, which is above the required 50 ft-lbs and the minimum lateral expansion was 82 mils, which is above the required 35 mils minimum. Based on these requirements, $RT_{ndt}$ = -40 deg F.

Table 5.2-7

Replacement Pressurizer Ferritic Material Fracture Toughness Reference - Pressure Boundary

| Part Name | Heat Number | Location | Material | RTndt or Lowest Service Temperature Ref. | Notes |
|---|---|---|---|---|---|
| Upper Head | T 1384 | Upper Head | SA-508 Gr 3 Cl 2 | +9 degrees F. | 1, 7 |
| Upper Shell | T 1386 | Upper Shell | SA-508 Gr 3 Cl 2 | +17 degrees F. | 7 |
| Lower Shell | T 1385 | Lower Shell | SA-508 Gr 3 Cl 2 | +17 degrees F. | 7 |
| Lower Head | T 1383 | Lower Head | SA-508 Gr 3 Cl 2 | minus 9 degrees F. | 2, 7 |
| Manway Cover | 11727.1 | Upper Head | SA-533 Tp B Cl 2 | minus 9 degrees F. | |
| Manway Bolts | N 9879 / U3B | Upper Head | SA-540 B24 Cl 3 | Test Temperature 40 degrees F.<br>Cv ft-lbs 58.3, 58.3, 59<br>MLE (mils) 28.5, 35.8, 32.8 | 3 |
| Manway Nuts | F87688 | Upper Head | SA-193 B7 | Test Temperature 40 degrees F.<br>Cv ft-lbs 79, 81, 76,<br>MLE (mils) 43.2, 52.4, 48.4<br>Test Temperature 60 degrees F.<br>Cv ft-lbs 81, 80, 82<br>MLE (mils) 45.7, 47.7, 52.7 | 4 |

Replacement Pressurizer Ferritic Material Fracture Toughness Reference - Non-Pressure Boundary

| Part Name | Heat Number | Location | Material | RTndt or Lowest Service Temperature Ref. | Notes |
|---|---|---|---|---|---|
| Skirt Cylinder | 4-1575 | Lower Head | SA-508 Gr 3 Cl 2 | Test temperature zero degrees F.<br>$C_V$ Ft-lbs 66, 76, 92<br>MLE (mils) 47, 54, 56 | 5 |
| Skirt Flange | 4-1575 | Lower Skirt Shell | SA-508 Gr 3 Cl 2 | Test temperature zero degrees F.<br>$C_V$ Ft-lbs 105, 89, 107<br>MLE (mils) 71, 63, 70 | 5 |
| Luft Lug | 10887.2 | Upper Head | SA-533 Tp B Cl 2 | minus 45 degrees F. | 6 |

Notes:
1) Ferritic portion of spray nozzle, safety nozzle, relief nozzle and manway boss integral with upper head.
2) Ferritic portion of the surge nozzle integral with lower head.
3) Lowest service temperature 40 degrees F.
4) Lowest service temperature 40 degrees F. Under 4 inch only MLE greater than 25 mils, Cv greater than 45 required.
5) NF component lowest service temperature is zero degrees F.
6) ANSI 14.6 lowest lift temperature equals minus 5 degrees.
7) Actual material test was performed per ASTM E208-81. The required test method is ASTM E208-91. An additional margin of 27°F was added to the actual $T_{NDT}$ test result (and $RT_{NDT}$) to make the results equivalent to the ASTM E208-91 method.

EC 291392

TABLE 5.2-8

CHARPY V-NOTCH AND DROP WEIGHT TEST VALUES - STEAM GENERATOR 1A

| Part No. | Location | Material | Heat | $RT_{NDT}$ | Absorbed Energy (ft-lbf) Normal to Principal Working Direction (NPWD) | |
|---|---|---|---|---|---|---|
| 5056021-2 | Tube Sheet | SA-508 Class 3 | 92W99-1-1 | -30ºF | 108-86-87 (94 avg.)<br>101-104-106 (104 avg.)<br>100-99-90 (96 avg.)<br>108-97-122 (109 avg.)<br>Tests at @30ºF | 112-113-114 (113 avg.)<br>84-92-95 (90 avg.)<br>105-89-63 (86 avg.)<br>94-87-98 (93 avg.) |
| 5056020-2 | Primary Head | SA-508 Class 3 | 92W109-1-1 | -50ºF | 141-129-122 (131 avg.)<br>126-138-118 (127 avg.)<br>Tests @10 ºF | |
| 5056024-2 | Stay Cylinder | SA-508 Class 3 | 144857 | -18.4ºF | 60-75-67 (67 avg)*<br>68-71-62 (67 avg.)**<br>Tests @41.5ºF<br>* Heat Treatment 1 (20 hrs)<br>** Heat Treatment 2 (50.3 hrs) | |
| 5056022-02 | Inlet Nozzle | SA-508 Class 3 | 61361-2A1 | -30ºF | 92-68-81 (80 avg)<br>Test @10ºF<br>88-96-100 (95 avg.)<br>Test @30ºF | |
| 5056025-02 | Inlet Nozzle Safe End | SA-508 Class 1 | 61383-3A1 | -50 ºF | 99-115-100 (avg. 105)<br>94-120-106 (avg. 107)<br>Tests @10ºF | |
| 5056023-1 | Outlet Nozzle | SA-508 Class 3 | 61361-1A0 | -50ºF | 66-88-92 (82 avg.)<br>Two Retests 78-56 (67 avg.)<br>Tests @10ºF | |
| 5056023-3 | Outlet Nozzle | SA-508 Class 3 | 61361-3A0 | -50ºF | 66-88-92 (82 avg.)<br>Two Retests 78-56 (67 avg.)<br>Tests @10ºF | |
| 5056026-1 | Outlet Nozzle Safe-End | SA-508 Class 1 | 61383-1A0 | -40ºF | 117-110-108 (112 avg.)<br>107-104-105 (105 avg.)<br>Tests@20ºF | |
| 5056026-3 | Outlet Nozzle Safe-End | SA-508 Class 1 | 61383-3A0 | -40ºF | 117-110-108 (112 avg.)<br>107-104-105 (105 avg.)<br>Tests@20ºF | |
| 5143871-3 | Manway Cover Y-2 | SA-533 Gr. B Class 1 | 3668-5 | -3.4 ºF | 61-100-91(84 avg)<br>Test@-4ºF | |
| 5143871-1 | Manway Cover X-2 | SA-533 Gr. B Class 1 | 3668-5 | -3.4 ºF | 61-100-91(84 avg)<br>Test@-4ºF | |
| 5120220 | Manway Studs | SA-193 B7 | 8075494 | ---- | 84-89-95 (89 avg.)<br>85-106-102 (98 avg.)<br>Tests @40ºF | |

TABLE 5.2-9

CHARPY V-NOTCH AND DROP WEIGHT TEST VALUES - STEAM GENERATOR 1B

| Part No. | Location | Material | Heat | $RT_{NDT}$ | Absorbed Energy (ft-lbf) Normal to Principal Working Direction (NPWD) |
|---|---|---|---|---|---|
| 5056021-1 | Tube Sheet | SA-508 Class 3 | 92W98-1-1 | -50ºF | 84-91-78 (84 avg.)<br>90-88-67 (82 avg.)<br>Tests @10 ºF |
| 5056020-1 | Primary Head | SA-508 Class 3 | 92W108-1-1 | -50ºF | 98-148-128 (125 avg.)<br>129-89-115 (111 avg.)<br>Tests @10ºF |
| 5056024-1 | Stay Cylinder | SA-508 Class 3 | 144857 | -18.4ºF | 92-77-89 (avg. 86)*<br>72-74-63 (avg. 70)**<br>Tests @41.5 ºF<br>* Heat Treatment 1 (20 hrs)<br>** Heat Treatment 2 (50.3 hrs) |
| 5056022-01 | Inlet Nozzle | SA-508 Class 3 | 61361-1A1 | -30ºF | 92-68-81 (80 avg)<br>Test @10ºF<br>88-96-100 (95 avg.)<br>Test @30ºF |
| 5056025-01 | Inlet Nozzle Safe End | SA-508 Class 1 | 61383-1A1 | -50 ºF | 99-115-100 (avg. 105)<br>94-120-106 (avg. 107)<br>Tests @10ºF |
| 5056023-02 | Outlet Nozzle | SA-508 Class 3 | 61361-2A0 | -50ºF | 66-88-92 (82 avg.)<br>Two Retests 78-56 (67 avg.)<br>Tests @10ºF |
| 5056023-04 | Outlet Nozzle | SA-508 Class 3 | 61361-4A0 | -50ºF | 66-88-92 (82 avg.)<br>Two Retests 78-56 (67 avg.)<br>Tests @10ºF |
| 5056026-02 | Outlet Nozzle Safe-End | SA-508 Class 1 | 61383-2A0 | -40ºF | 117-110-108 (112 avg.)<br>107-104-105 (105 avg.)<br>Tests @20ºF |
| 5056026-05 | Outlet Nozzle Safe-End | SA-508 Class 1 | 61383-5A0 | -40ºF | 117-110-108 (112 avg.)<br>107-104-105 (105 avg.)<br>Tests @20ºF |
| 5143871 | Manway Cover Y-2 | SA-533 Gr. B Cl 1 | 3668-5 | -3.4 ºF | 61-100-91(84 avg)<br>Test @-4ºF |
| 5143871 | Manway Cover X-2 | SA-533 Gr. B Cl 1 | 3668-5 | -3.4 ºF | 61-100-91(84 avg)<br>Test @-4ºF |
| 5120220 | Manway Studs | SA-193 B7 | 8075494 | ---- | 84-89-95 (89 avg.)<br>85-106-102 (98 avg.)<br>Tests @40ºF |

TABLE 5.2-10

CHARPY V-NOTCH AND DROP WEIGHT TEST VALUES - REACTOR COOLANT PIPING

| | | | | Charpy V-Notch Values @ 10F (ft.-lbs.) | |
|---|---|---|---|---|---|
| Piece No. | Code No. | Location | Material | 0° | 180° |
| 502-02-1 | C-4305-1 | ELL SEGMENT | SA-516 GRADE 70 | 55-54-39 (49.3) | |
| 502-02-2 | C-4305-1 | ELL SEGMENT | " | 55-54-39 (49.3) | |
| 502-20-1 | C-4301-1 | PIPE SEGMENT | " | 54-43-42 (46.3) | |
| 502-20-2 | C-4301-2 | PIPE SEGMENT | " | 54-43-42 (46.3) | |
| 509-02 | C-4312 | NOZZLE FORGING | SA-105 GRADE 2 | 36-33-31 (33.3) | |
| 509-08 | C-4324-1 | NOZZLE FORGING | " | 52-80-63 (65) | |
| 502-20-3 | C-4301-3 | PIPE SEGMENT | SA-516 GRADE 70 | 55-44-52 (50.3) | |
| 502-20-4 | C-4301-4 | PIPE SEGMENT | " | 55-44-52 (50.3) | |
| 502-02-3 | C-4305-1 | ELL SEGMENT | " | 55-54-39 (49.3) | |
| 502-02-4 | C-4305-1 | ELL SEGMENT | " | 55-54-39 (49.3) | |
| 509-11 | C-4310-1 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43.3) | |
| 509-08 | C-4311 | NOZZLE FORGING | " | 31-33-34 (32.7) | |
| 502-10-9 | C-4309-2 | ELL SEGMENT | SA-516 GRADE 70 | 37-42-34 (37.7) | |
| 502-10-10 | C-4309-2 | ELL SEGMENT | " | 37-42-34 (37.7) | |
| 502-18-1 | C-4302-1 | PIPE SEGMENT | " | 45-48-43 (45.3) | |
| 502-18-2 | C-4302-2 | PIPE SEGMENT | " | 45-48-43 (45.3) | |
| 508-02-1 | C-4316-1 | NOZZLE FORGING | SA-182 GRADE F1 | 64-71-92 (75.7) | |
| 508-02-1 | C-4316-1 | NOZZLE FORGING | SA-182 GRADE F1 | | 85-92-85 (87.3) |
| 502-10-11 | C-4309-2 | ELL SEGMENT | SA-516 GRADE 70 | 37-42-34 (37.7) | |
| 502-10-12 | C-4309-2 | ELL SEGMENT | " | 37-42-34 (37.7) | |
| 502-18-3 | C-4302-3 | PIPE SEGMENT | " | 45-48-43 (45.3) | |
| 502-18-4 | C-4302-4 | PIPE SEGMENT | " | 55-43-43 (47) | |
| 508-02-3 | C-4316-3 | NOZZLE FORGING | SA-182 GRADE F1 | 105-84-87 (92) | |
| 508-02-3 | C-4316-3 | NOZZLE FORGING | " | | 88-100-108 (98.6) |
| 507-07-1 | C-4315-1 | NOZZLE FORGING | " | 49-50-31 (43.3) | |

TABLE 5.2-10 (Cont'd)

| | | | | Charpy V-Notch Values @ 10F (ft.-lbs.) | |
|---|---|---|---|---|---|
| Piece No. | Code No. | Location | Material | 0° | 180° |
| 502-12-1 | C-4304-1 | PIPE SEGMENT | SA-516 GRADE 70 | 50-48-50 (49.3) | |
| 502-12-2 | C-4304-2 | PIPE SEGMENT | " | 52-51-55 (52.7) | |
| 502-08-l | C-4308-1 | ELL SEGMENT | " | 40-30-28 (32.7) | |
| 502-08-2 | C-4308-1 | ELL SEGMENT | " | 40-30-28 (32.7) | |
| 507-02-2 | C-4314-2 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43.3) | |
| 507-07-2 | C-4315-2 | NOZZLE FORGING | " | 49-50-31 (43.3) | |
| 508-08-2 | C-4316-2 | NOZZLE FORGING | SA-182 GRADE F1 | 92-71-91 (84.7) | |
| 508-08-2 | C-4316-2 | NOZZLE FORGING | SA-182 GRADE F1 | | 91-66-84 (80.3) |
| 502-12-3 | C-4304-3 | PIPE SEGMENT | SA-516 GRADE 70 | 51-51-55 (52.3) | |
| 502-12-4 | C-4304-4 | PIPE SEGMENT | " | 42-58-50 (50) | |
| 502-08-3 | C-4308-1 | ELL SEGMENT | " | 40-30-28 (32.7) | |
| 502-08-4 | C-4308-1 | ELL SEGMENT | " | 40-30-28 (32.7) | |
| 507-02-1 | C-4314-1 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43.3) | |
| 508-02-4 | C-4316-4 | NOZZLE FORGING | SA-182 GRADE F1 | 116-104-85 (101.7) | |
| 502-14-1 | C-4304-5 | PIPE SEGMENT | SA-516 GRADE 70 | 60-54-48 (54) | |
| 501-14-2 | C-4304-6 | PIPE SEGMENT | " | 36-36-36 (36) | |
| 502-10-1 | C-4309-1 | ELL SEGMENT | “ | 39-44-48 (43.7) | |
| 502-10-2 | C-4309-1 | ELL SEGMENT | " | 39-44-48 (43.7) | |
| 507-10-1 | C-4313-1 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43.3) | |
| 502-14-1 | C-4304-5 | PIPE SEGMENT | SA-516 GRADE 70 | 60-54-48 (54) | |
| 502-14-2 | C-4304-6 | PIPE SEGMENT | " | 36-36-36 (36) | |
| 502-14-2 | C-4304-6 | PIPE SEGMENT | " | 34-37-60 (43.7) | |
| 502-10-1 | C-4309-1 | ELL SEGMENT | “ | 34-37-60 (43.7) | |
| 502-10-2 | C-4309-1 | ELL SEGMENT | " | 34-37-60 (43.7) | |
| 507-10-2 | C-4313-2 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43-3) | |

TABLE 5.2-10 (Cont'd)

| PIECE NO. | CODE NO. | DESCRIPTION | MATERIAL | CHARPY V-NOTCH VALUES @ 10F (FT.-LBS.), 0° |
|---|---|---|---|---|
| 502-06-1 | C-4307 | ELL SEGMENT | SA-516 GRADE 70 | 29-40-30 (33) |
| 502-06-2 | C-4307 | ELL SEGMENT | " | 29-40-30 (33) |
| 502-16-1 | C-4303-1 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-16-2 | C-4303-2 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-06-3 | C-4307-1 | ELL SEGMENT | SA-516 GRADE 70 | 29-40-30 (33) |
| 502-06-4 | C-4307-1 | ELL SEGMENT | " | 29-40-30 (33) |
| 502-16-3 | C-4303-1 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-16-4 | C-4303-2 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-06-5 | C-4307-1 | ELL SEGMENT | SA-516 GRADE 70 | 29-40-30 (33) |
| 502-06-6 | C-4307-1 | ELL SEGMENT | " | 29-40-30 (33) |
| 502-16-5 | C-4303-1 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-16-6 | C-4303-2 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-06-7 | C-4307-1 | ELL SEGMENT | SA-516 GRADE 70 | 29-40-30 (33) |
| 502-06-8 | C-4307-1 | ELL SEGMENT | " | 29-40-30 (33) |
| 502-16-7 | C-4303-1 | PIPE SEGMENT | " | 53-42-46 (47) |
| 502-16-8 | C-4303-2 | PIPE SEGMENT | " | 53-42-46 (47) |

TABLE 5.2-10 (Cont'd)

| PIECE NO. | CODE NO. | DESCRIPTION | MATERIAL | CHARPY V-NOTCH VALUES @ 10F (FT.-LBS.), 0° |
|---|---|---|---|---|
| 502-14-3 | C-4304-7 | PIPE SEGMENT | SA-516 GRADE 70 | 60-54-48 (54) |
| 502-14-4 | C-4304-8 | PIPE SEGMENT | " | 41-56-54 (50.3) |
| 502-10-5 | C-4309-1 | ELL SEGMENT | “ | 34-37-60 (43.7) |
| 502-10-6 | C-4309-1 | ELL SEGMENT | “ | 34-37-60 (43.7) |
| 507-10-3 | C-4313-3 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43.3) |
| 502-14-3 | C-4304-7 | PIPE SEGMENT | SA-516 GRADE 70 | 60-54-48 (54) |
| 502-14-4 | C-4304-8 | PIPE SEGMENT | “ | 41-56-54 (50.3) |
| 502-10-7 | C-4309-2 | ELL SEGMENT | “ | 37-42-34 (37.7) |
| 502-10-8 | C-4309-2 | ELL SEGMENT | “ | 37-42-34 (37.7) |
| 507-10-4 | C-4313-4 | NOZZLE FORGING | SA-105 GRADE 2 | 49-50-31 (43.3) |
| 502-04-7 | C-4306-2 | ELL SEGMENT | SA-516 GRADE 70 | 43-32-31 (35.3) |
| 502-04-8 | C-4306-2 | ELL SEGMENT | “ | 43-32-31 (35.3) |
| 502-04-1 | C-4306-1 | ELL SEGMENT | SA-516 GRADE 70 | 33-29-34 (32) |
| 502-04-2 | C-4306-1 | ELL SEGMENT | “ | 33-29-34 (32) |
| 502-04-3 | C-4306-1 | ELL SEGMENT | SA-516 GRADE 70 | 33-29-34 (32) |
| 502-04-4 | C-4306-1 | ELL SEGMENT | “ | 33-29-34 (32) |
| 502-04-5 | C-4306-2 | ELL SEGMENT | SA-516 GRADE 70 | 43-32-31 (35.3) |
| 502-04-6 | C-4306-2 | ELL SEGMENT | “ | 43-32-31 (35.3) |

## TABLE 5.2-11
## REACTOR COOLANT LEAK DETECTION SENSITIVITY*

| Leakage Source | Detection Instrumentation | Instrument(10) Range | Normal Reading | Average Rate of Change for 1.0 gpm leak | Time for Scale to Move 10% from Normal Reading for 1.0 gpm leak |
|---|---|---|---|---|---|
| 1. Direct | Sump level measurement system | | | | |
| | Containment Radiation | | | $8.43 \times 10^{-8}$ µCi/cc – min (Noble gases) | 15.1 hr. |
| | | | | $1.68 \times 10^{-10}$ µCi/cc – min (2) (Cs – 137) | 18.1 hr. |
| 2. Relief and Safety Valves | Discharge Line Temperature | | Ambient | | $<$1.0 min. |
| | Quench Tank Water Level | | 29 in. (60% Indicated Lvl.) | 0.03 in/min | 1.7 hr. |
| | Acoustic Monitor(9) | | N/A | N/A | N/A |
| 3. S.I. Tank Check Valves | S.I. Tank Water Level | | 224.7 in. (91.4% Indicated Lvl.) | 0.025 in/min | 7.6 hr.(7) |
| | S.I. Tank Pressure | | 215 psig | 0.043 psi/min | 8.4hr. |
| 4. Heat Exchangers | CCW Radiation | | Background | $1.25 \times 10^{-5}$ µCi/cc-min | <3.5 min.(3) |
| | CCW Surge Tank Water Level | | 40 in. | 1.8 in/hr | 8 hr. (4) |
| 5. Steam Generator Tubing | *Blowdown Line Radiation | | Background | | <20 min. |
| | *Condenser Air Ejector Radiation | | Background | $1.25 \times 10^{-5}$ µCi/cc - min (Noble gases) $1.8 \times 10^{-4}$ µCi/cc - min | <2 min |

TABLE 5.2-11 (Cont'd)

REACTOR COOLANT LEAK DETECTION SENSITIVITY*

| Leakage Source | Detection Instrumentation | Instrument[10] Range | Normal Reading | Average Rate of Change for 1.0 gpm leak | Time for Scale to Move 10% from Normal Reading for 1.0 gpm leak |
|---|---|---|---|---|---|
| 6. Reactor Vessel Closure Head | O-Ring Space Pressure | | 0 | - | <2 min |
| 7. Reactor Coolant Pump Closure Cover | Gasket Space Pressure | | 0 | - | <1 min |
| 8. Safety Injection Isolation Check Valves | SI header Pressure | | 0 [6] | - | <2 min |
| 9. RCGVS | Discharge Line Pressure | | 0 | - | <2 min |

Notes

1. Deleted
2. Initial time rate of change based on step change in direct leakage from 0.1 to 1 gpm.
3. Includes the worst case transport time of 3 1/2 minutes around the CCW loop.
4. The time it takes to reach the high water level alarm of 54 inches.
5. Deleted
6. Normal pressure may vary from 0 psig to that pressure produced by the feet of head out to the Refueling Water Tank.
7. Time required to reach 100% indicated level. Two high level and two high pressure alarms actuate prior to this.
8. Normal Readings are based on expected nominal or average values; actual parameter values may vary at times within allowable operating tolerances.
9. Acoustic Monitors provide indication of flow through valve. One monitor on each safety and PORV (5 total) with indicator and alarm in control room.
10. Instrument ranges are selected in accordance with standard Engineering practices. Instrument accuracies are selected such that existing instrument loop performance and safety analysis assumptions remain valid. Where applicable, instrument accuracies are also evaluated for their impact on setpoints in accordance with the FPL Setpoint Methodology.

* Detection is based on .1 percent failed fuel

TABLE 5.2-12

PRESSURE ISOLATION VALVES

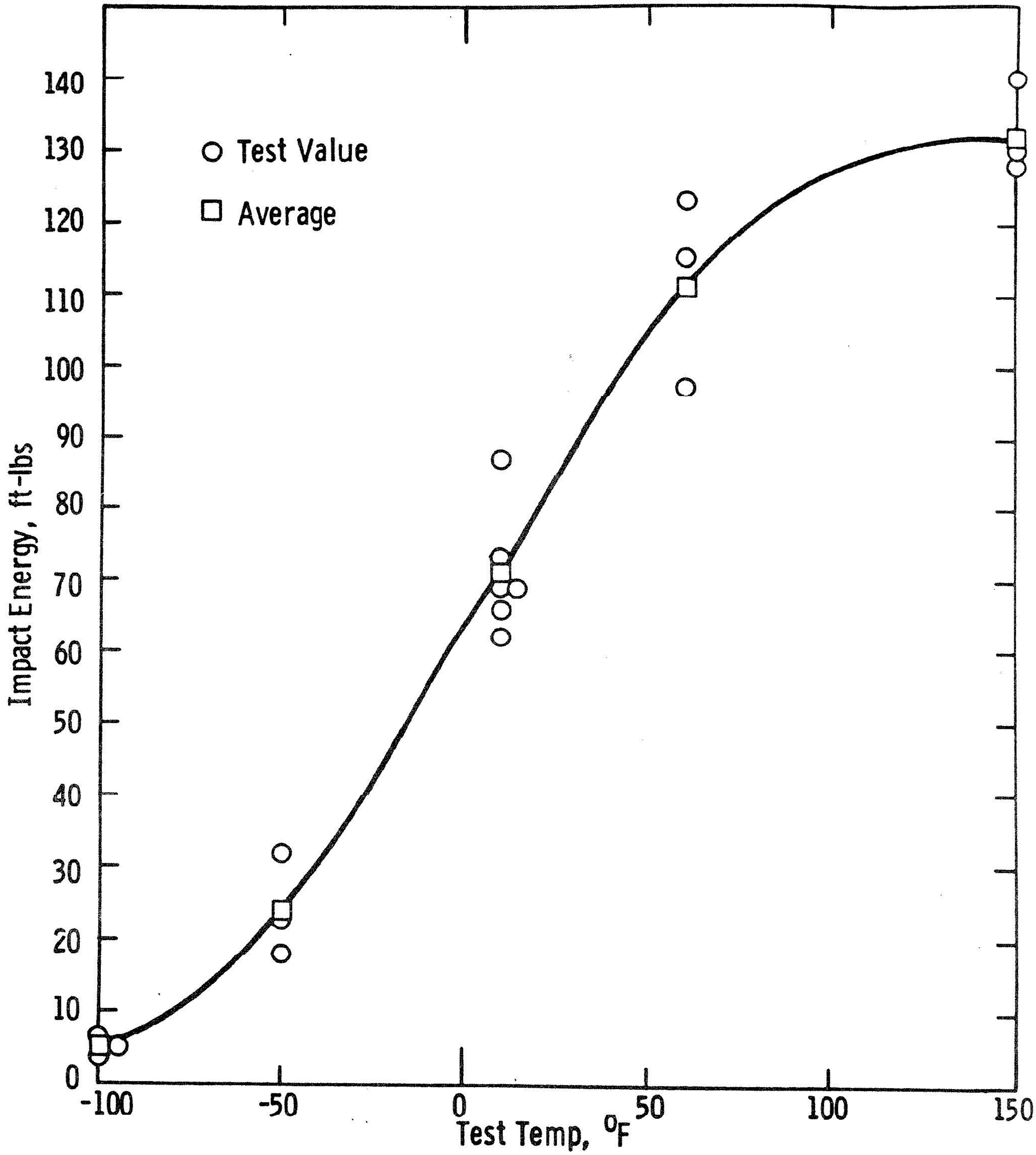
Addressed by Generic Letter 87-06

| Valve Number | Valve Function |
|---|---|
| V3227 | 1A1 SI HDR. CK. VALVE |
| V3217 | 1A2 SI HDR. CK. VALVE |
| V3237 | 1B1 SI HDR. CK. VALVE |
| V3247 | 1B2 SI HDR. CK. VALVE |
| V3225 | 1A1 SIT DISCH. CK. VALVE |
| V3215 | 1A2 SIT DISCH. CK. VALVE |
| V3235 | 1B1 SIT DISCH. CK. VALVE |
| V3245 | 1B2 SIT DISCH. CK. VALVE |
| V3123 | 1A1 HPSI HDR. CK. VALVE |
| V3113 | 1A2 HPSI HDR. CK. VALVE |
| V3133 | 1B1 HPSI HDR. CK. VALVE |
| V3143 | 1B2 HPSI HDR. CK. VALVE |
| V3124 | 1A1 LPSI HDR. CK. VALVE |
| V3114 | 1A2 LPSI HDR. CK. VALVE |
| V3134 | 1B1 LPSI HDR. CK. VALVE |
| V3144 | 1B2 LPSI HDR. CK. VALVE |
| V3480 | 1A SDC RTN. ISOL. VALVE |
| V3481 | 1A SDC RTN. ISOL. VALVE |
| V3652 | 1B SDC RTN. ISOL. VALVE |
| V3651 | 1B SDC RTN. ISOL. VALVE |

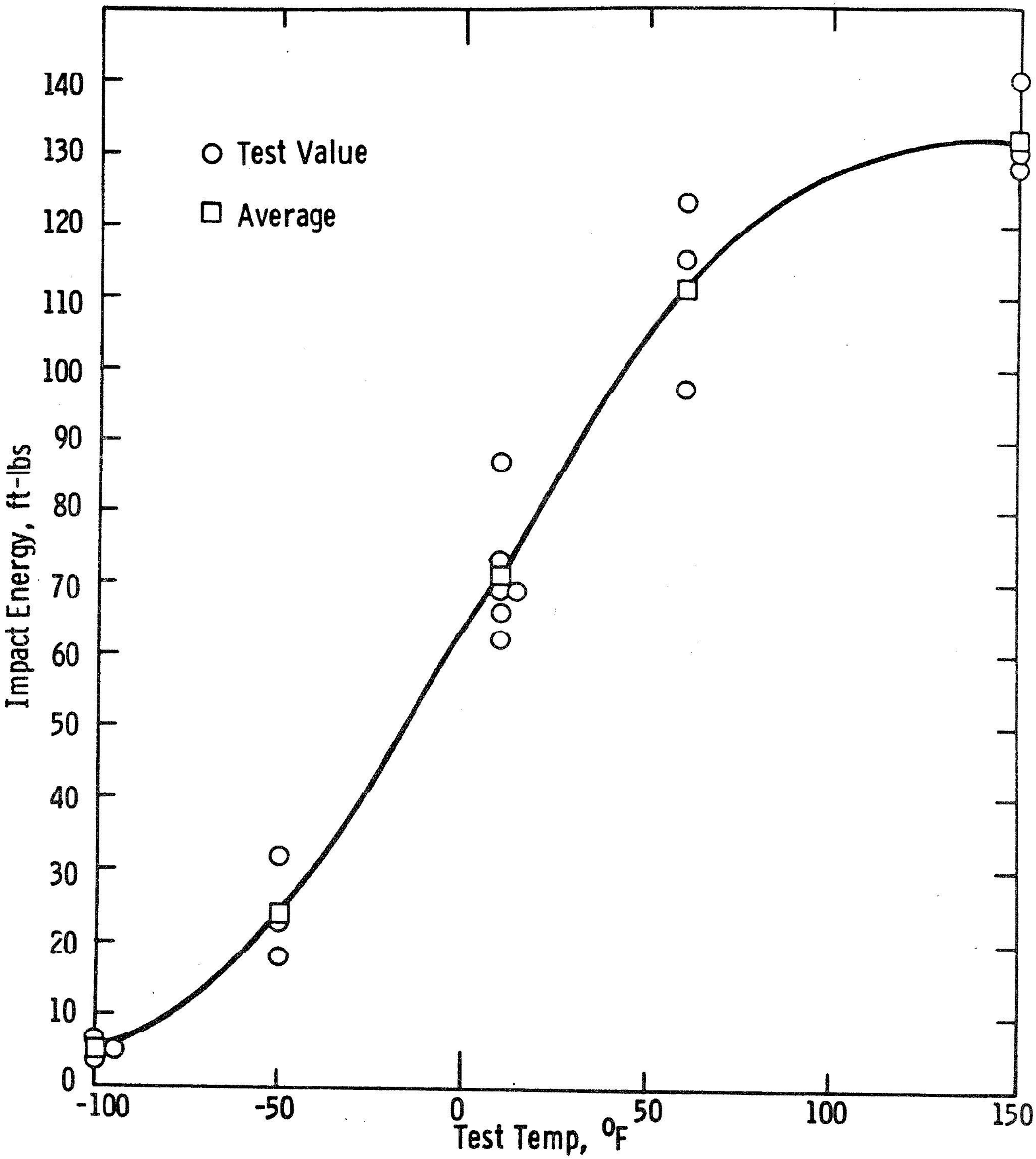
Note: Some of the valves above are not required by Technical Specifications to be leak tested; however, leak tight integrity of these valves is ensured through testing in accordance with plant procedures, or the valves are continuously monitored for indication of leakage by installed plant instrumentation/alarms to satisfy Generic Letter 87-06 requirements (Ref. 6).

Abbreviation Index:

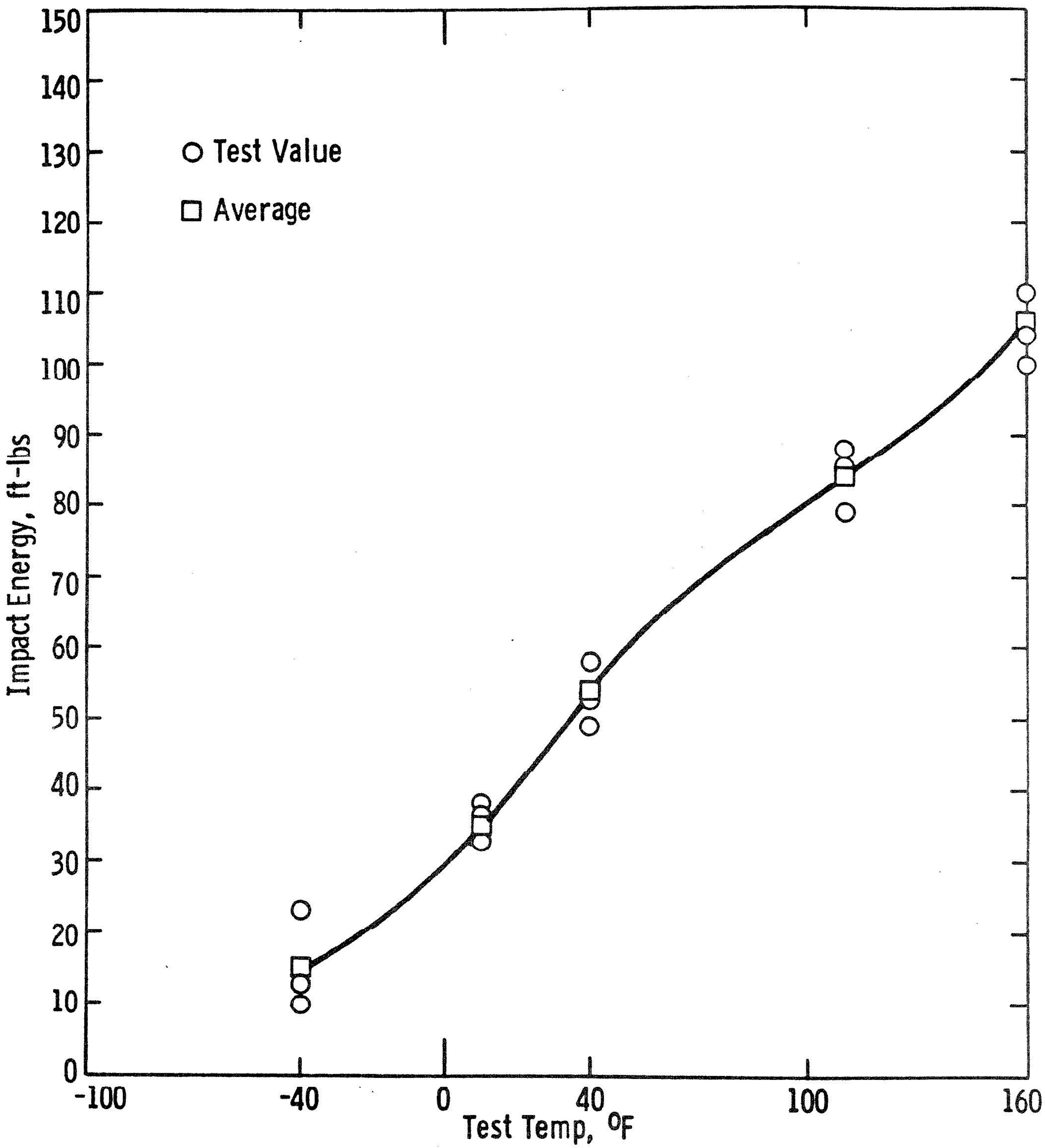
| | | |
|---|---|---|
| SI | = | Safety Injection |
| HDR | = | Header |
| CK | = | Check |
| SIT | = | Safety Injection Tank |
| DISCH | = | Discharge |
| HPSI | = | High Pressure Safety Injection |
| LPSI | = | Low Pressure Safety Injection |
| SDC | = | Shutdown Cooling |
| RTN | = | Return |
| ISOL | = | Isolation |



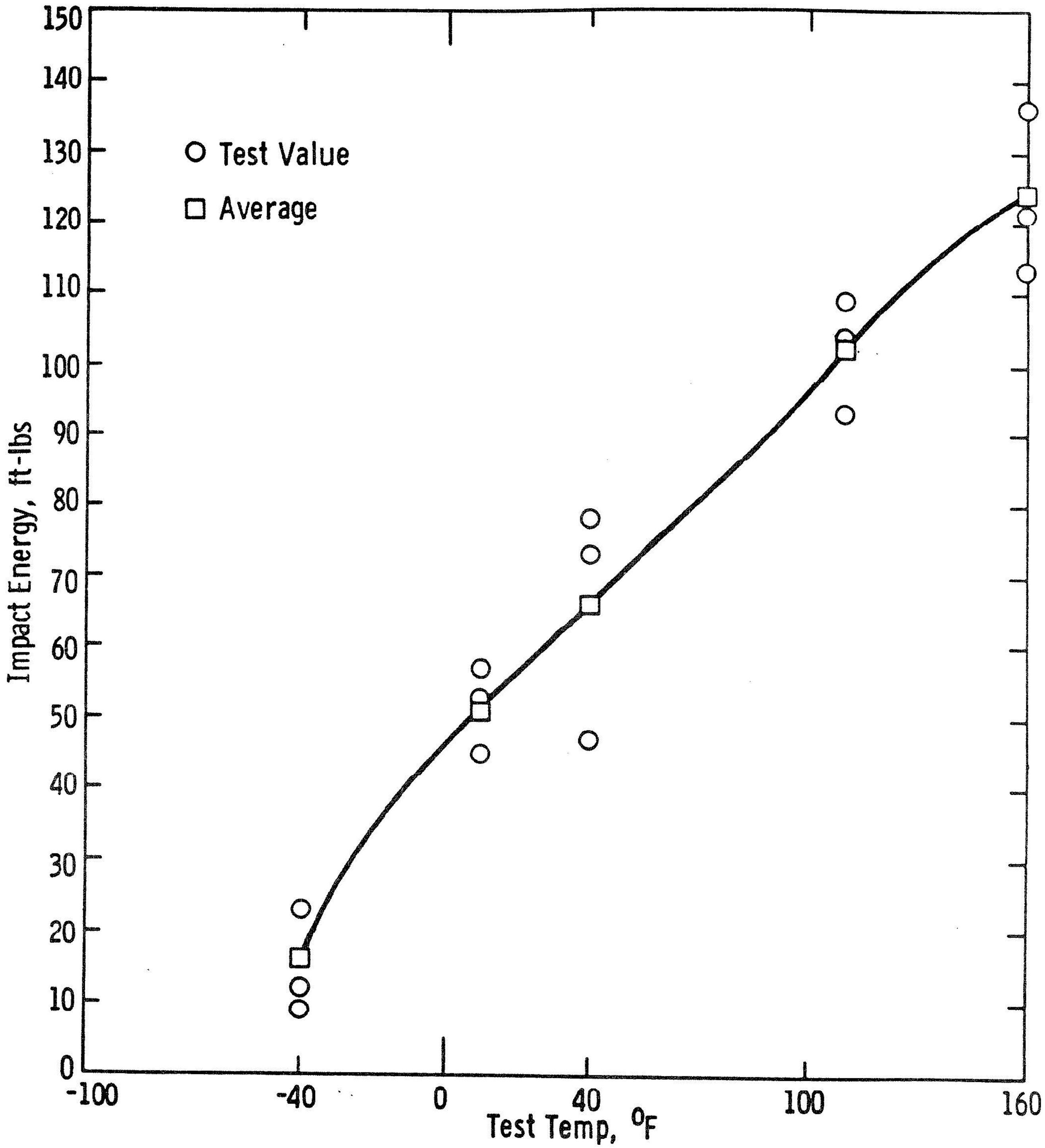

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>ST. LUCIE PLANT<br>UNIT 1 | Charpy V-Notch Impact Curve<br>Item Code C-1-1<br>Vessel Flange | Figure<br>5.2-1 |



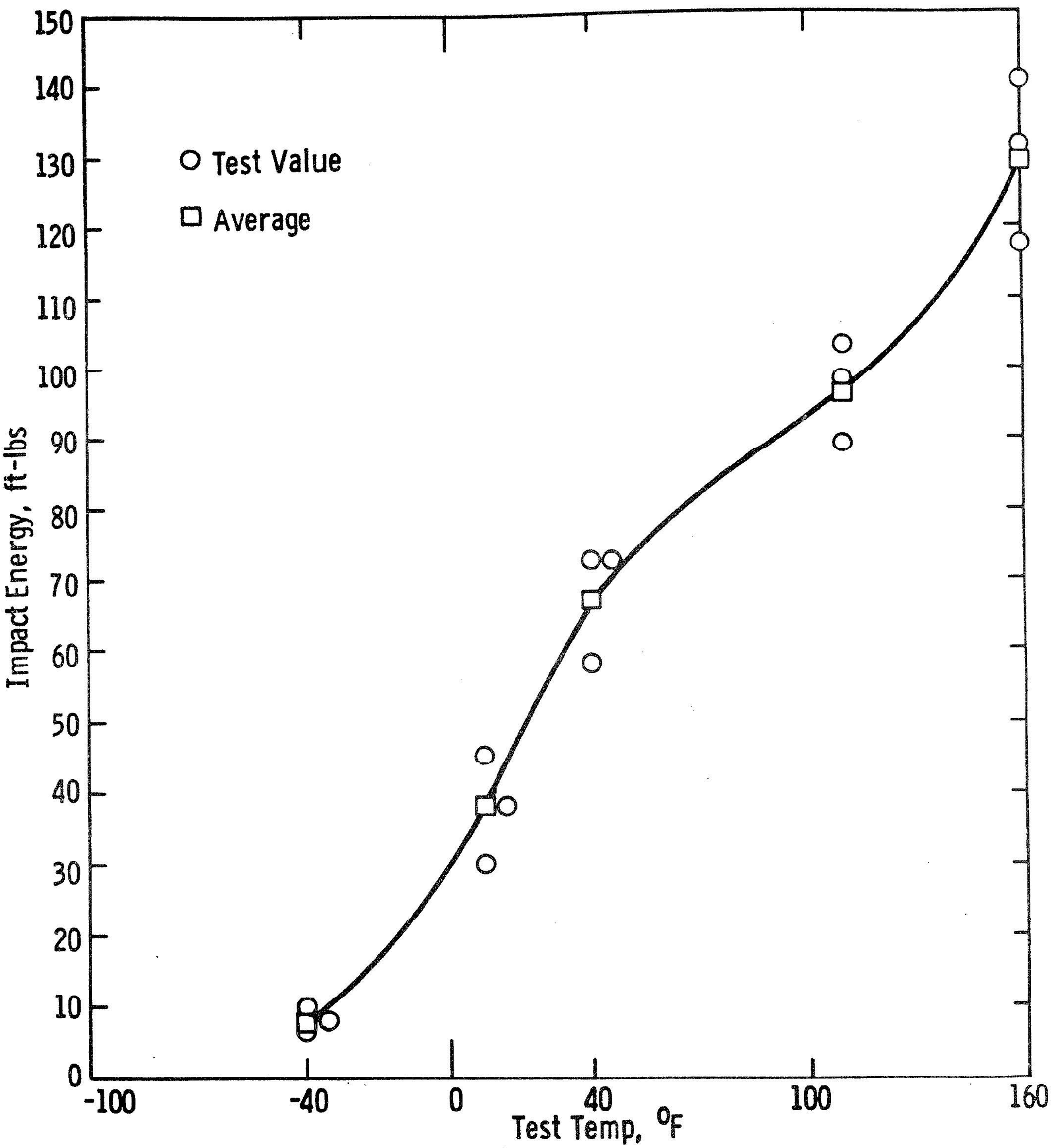

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>ST. LUCIE PLANT<br>UNIT 1 | Charpy V-Notch Impact Curve<br>Item Code C-1-1<br>Vessel Flange | Figure<br>5.2-1a |



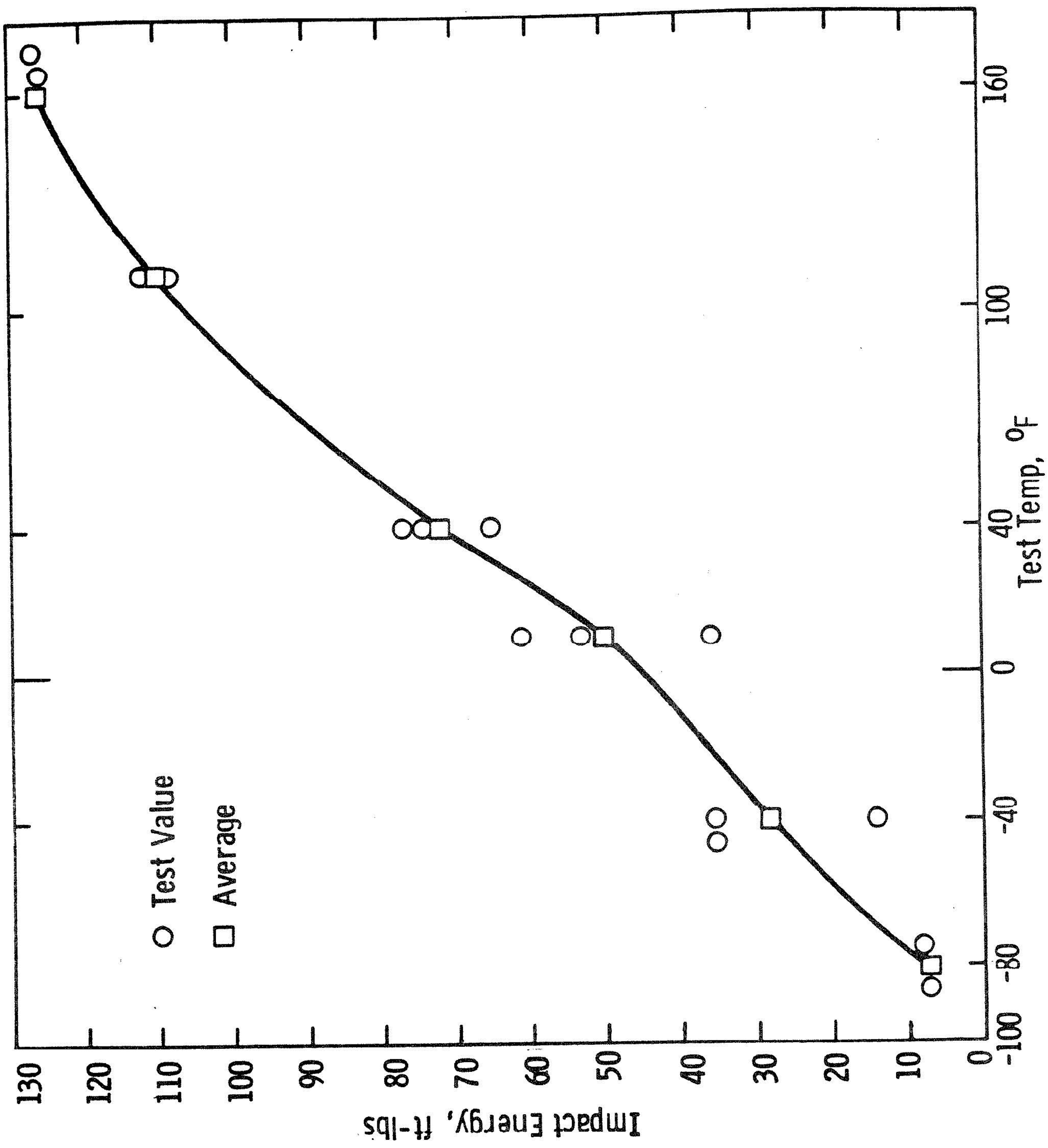

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve Item Code C-6-1 Upper Shell Plate | Figure 5.2-2 |
| --- | --- | --- |



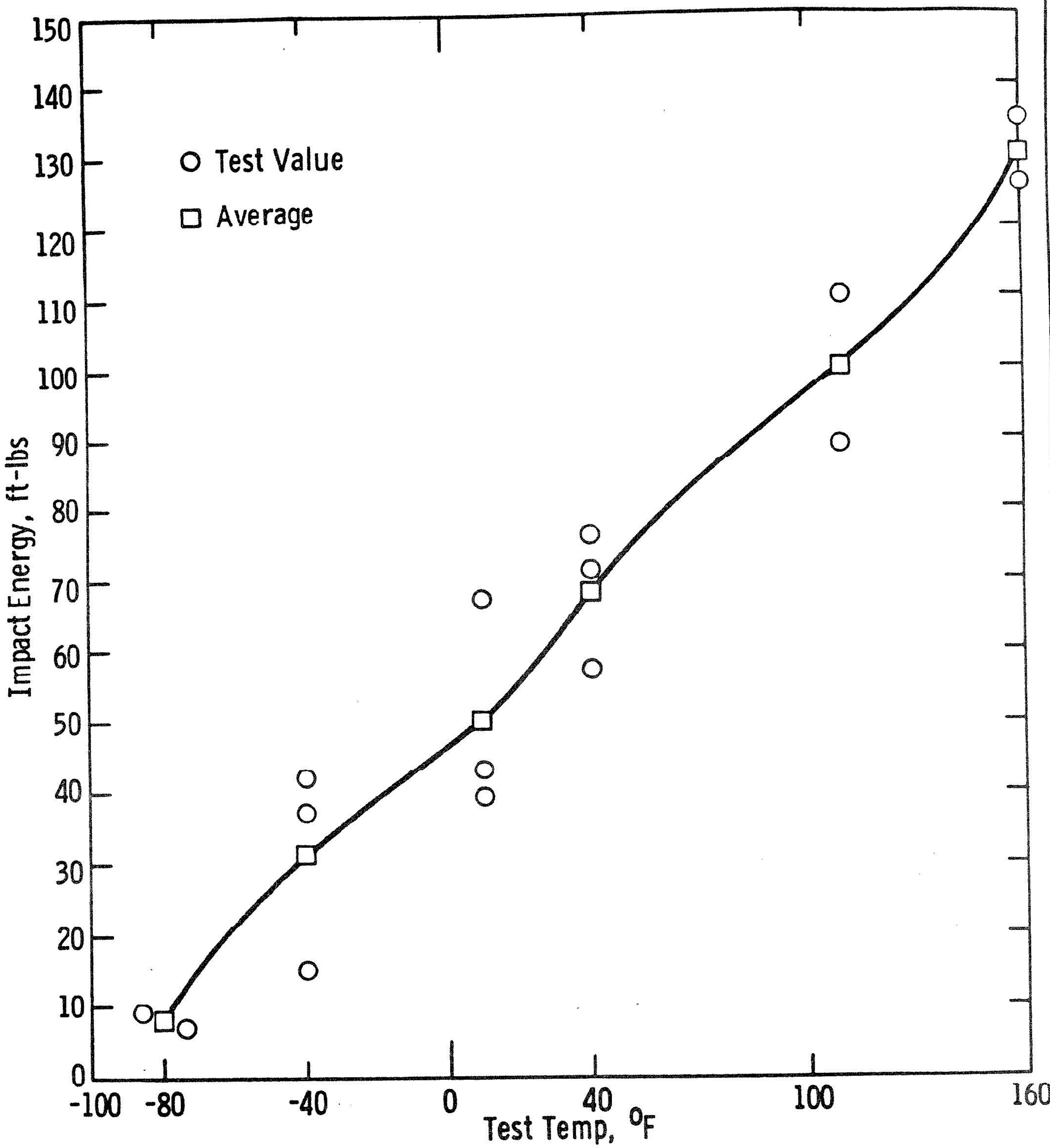

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-6-2<br>Upper Shell Plate | Figure 5.2-3 |
|---|---|---|



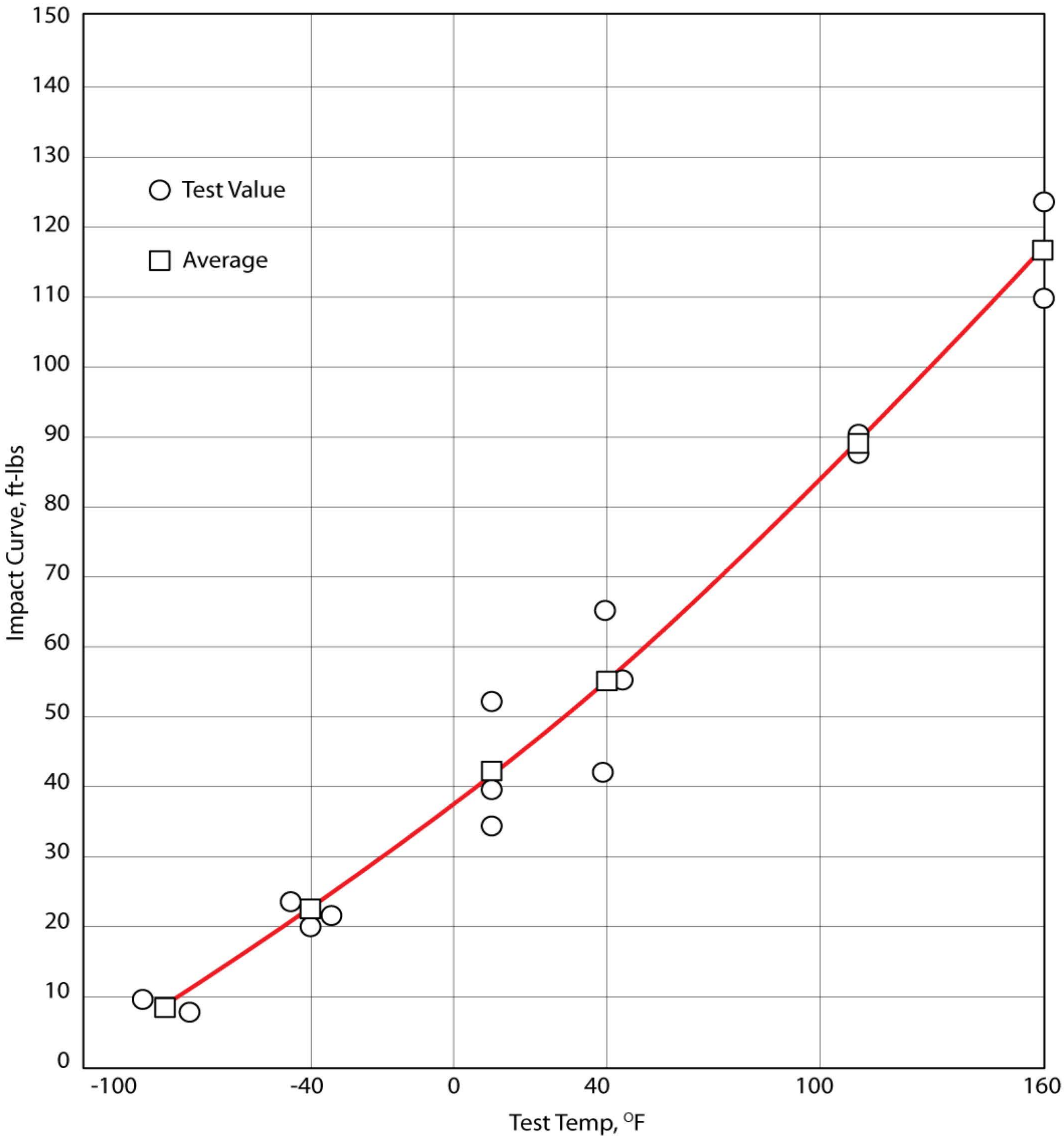

| FLORIDA POWER & LIGHT CO.<br>St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-6-3<br>Upper Shell Plate | Figure<br>5.2-4 |
|---|---|---|



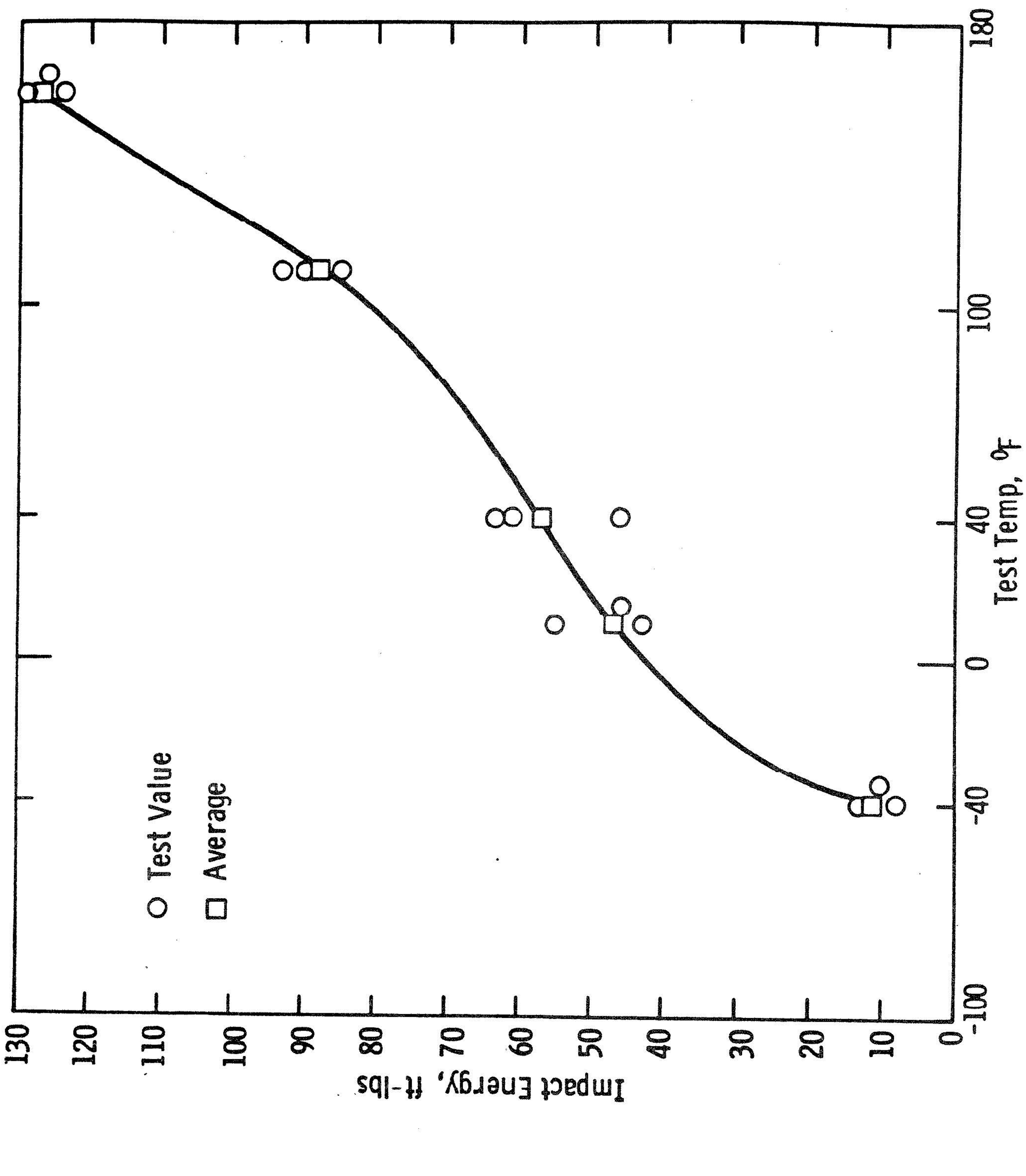

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve Item Code C-7-1 Intermediate Shell Plate | Figure 5.2-5 |
|---|---|---|



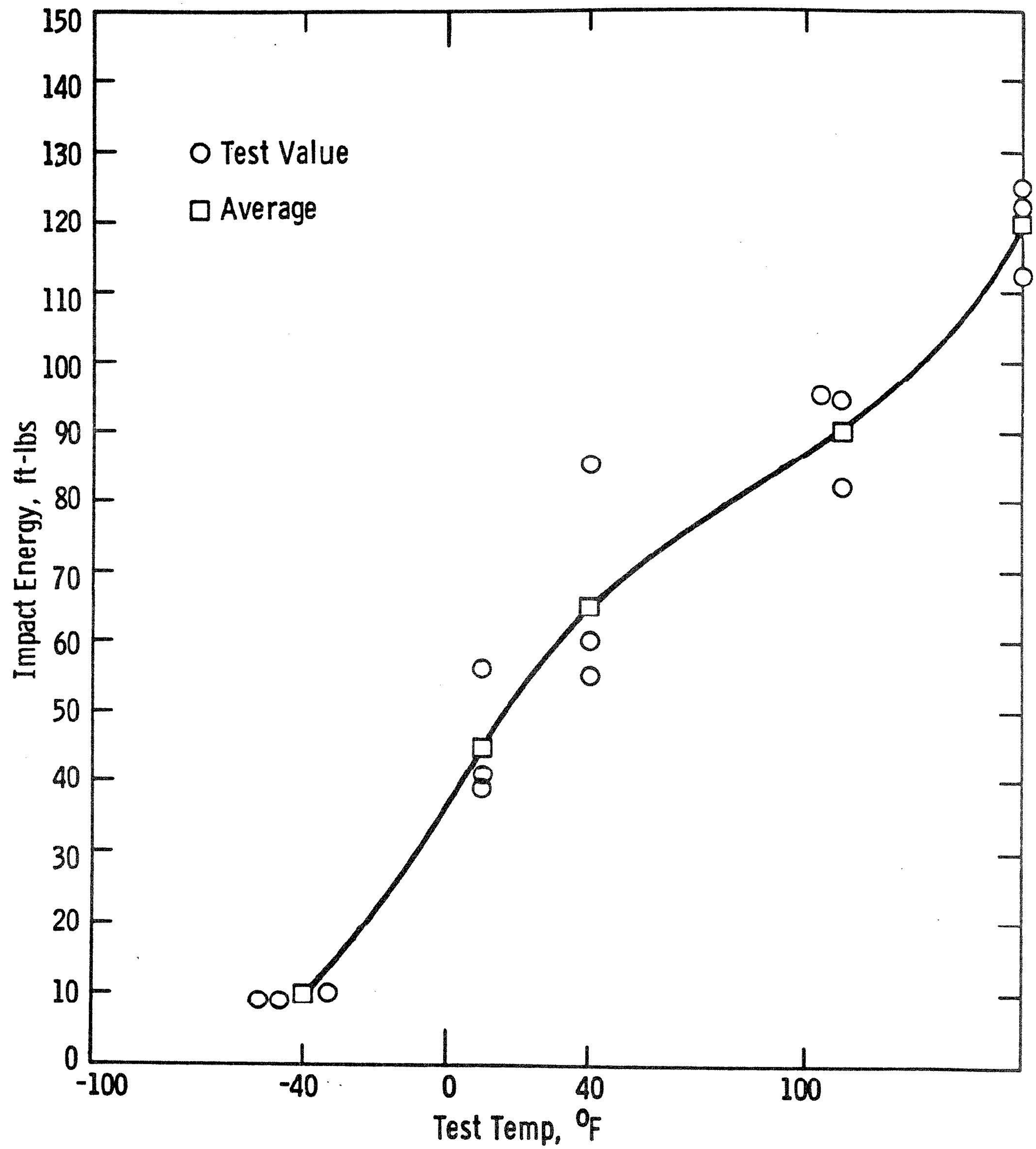

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-7-2<br>Intermediate Shell Plate | Figure 5.2-6 |
|---|---|---|




| | |
|---|---|
| FLORIDA POWER & LIGHT COMPANY<br>ST. LUCIE PLANT | CHARPY V-NOTCH IMPACT CURVE<br>ITEM CODE C-7-3<br>Intermediate Shell Plate FIGURE 5.2-7 |



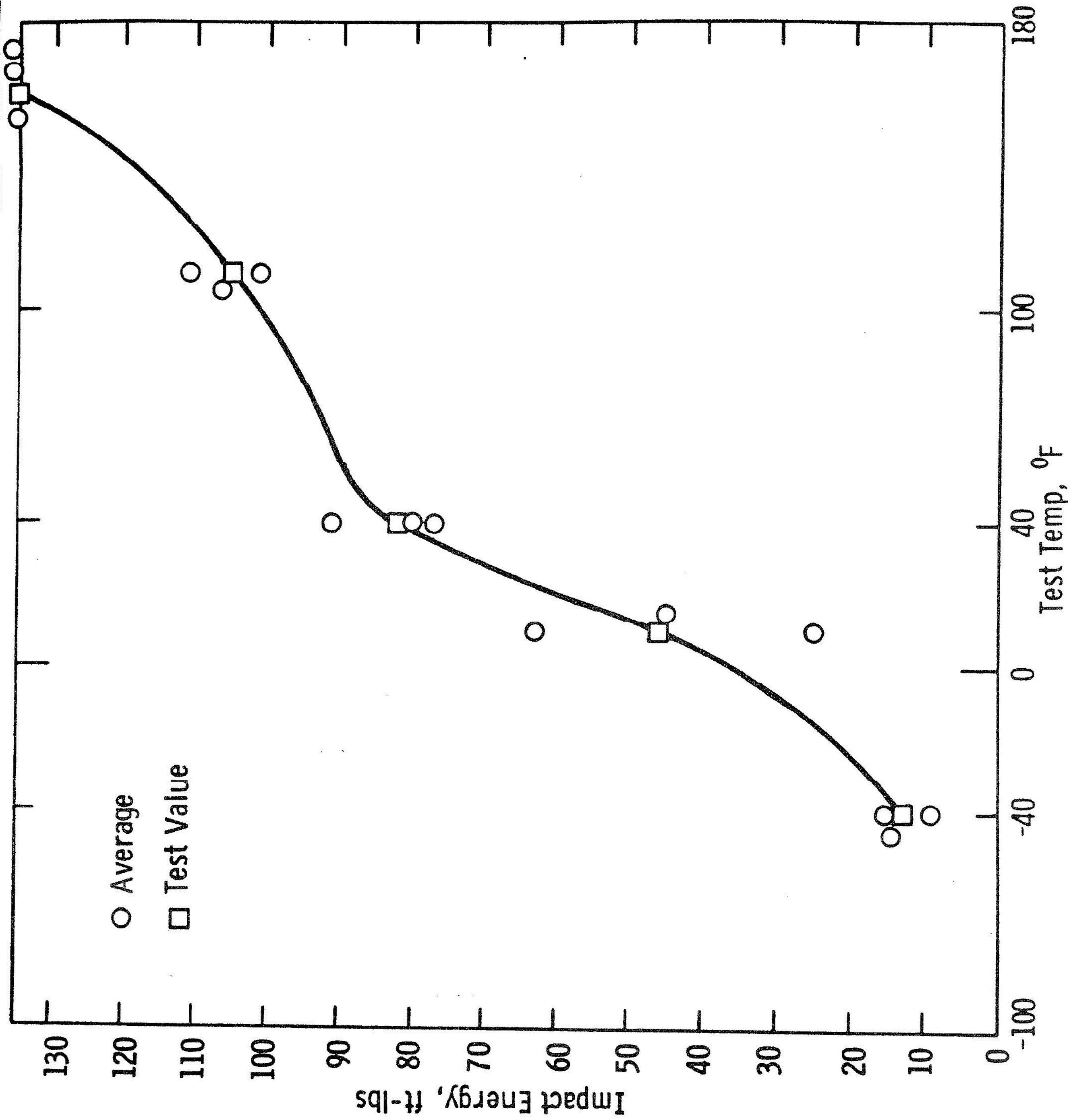

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-8-1<br>Lower Shell Plate | Figure<br>5.2-8 |



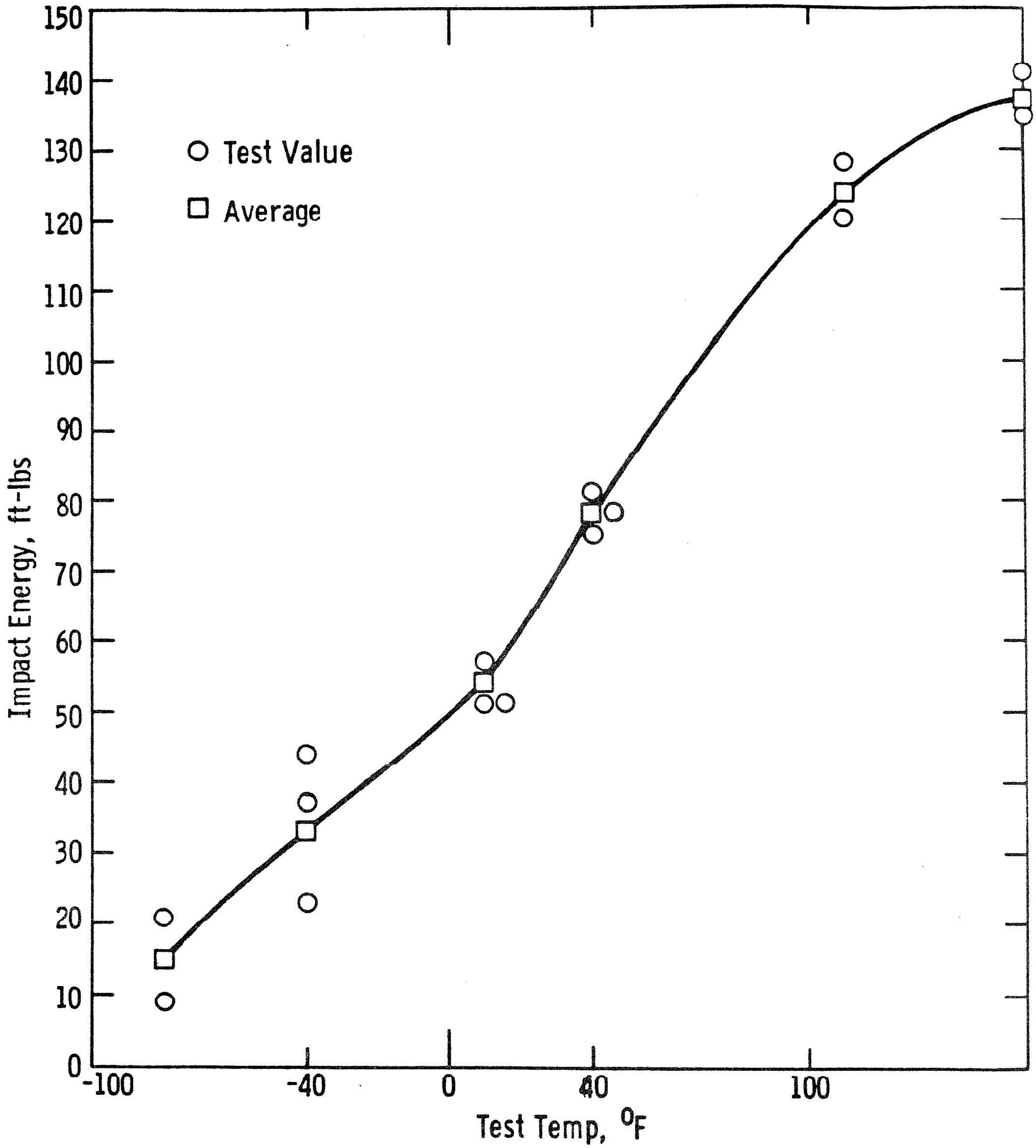

FLORIDA POWER & LIGHT CO.
St. Lucie Plant

Charpy V-Notch Impact Curve
Item Code C-8-2
Lower Shell Plate

Figure 5.2-9



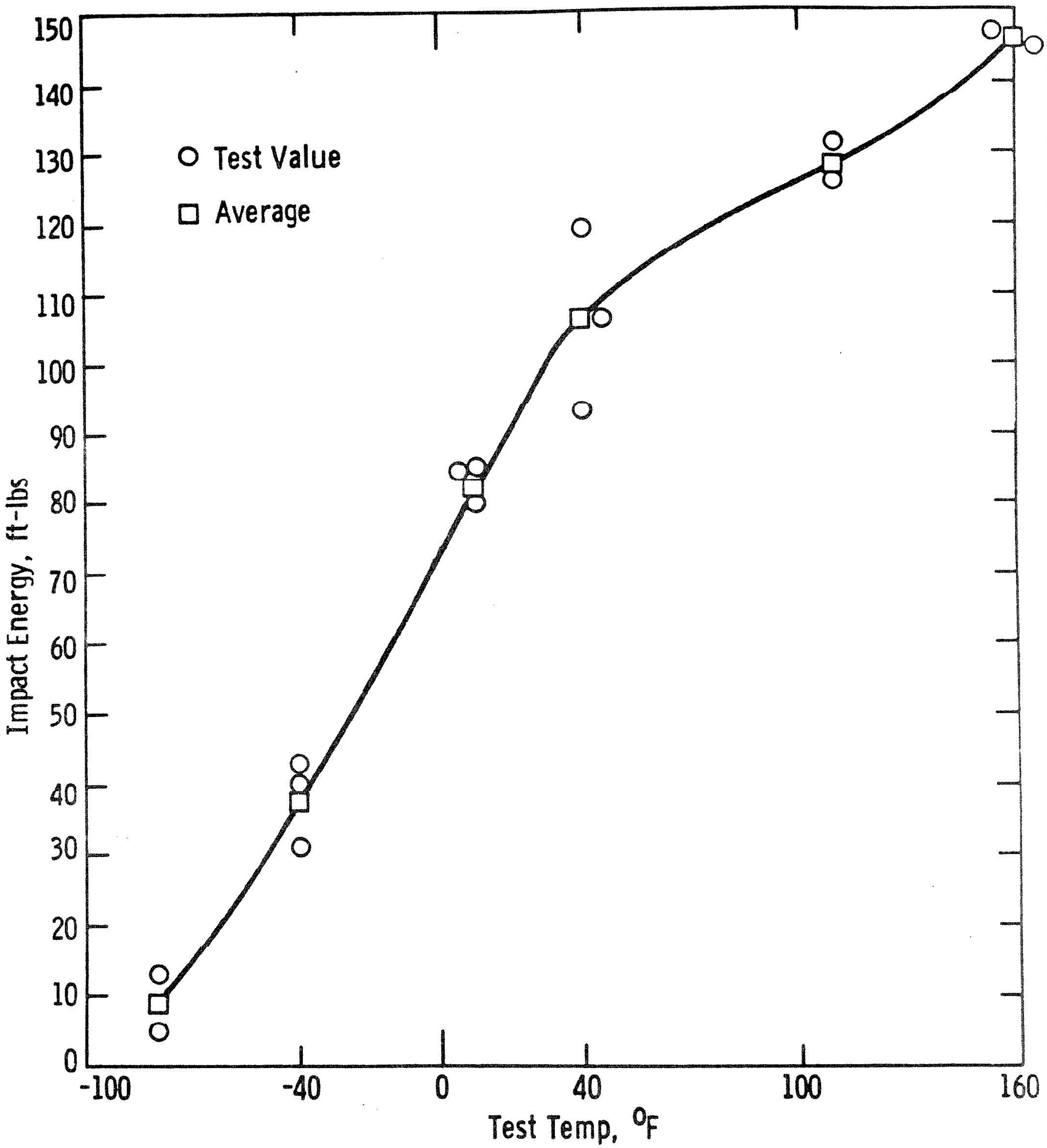

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-8-3<br>Lower Shell Plate | Figure<br>5.2-10 |
|---|---|---|



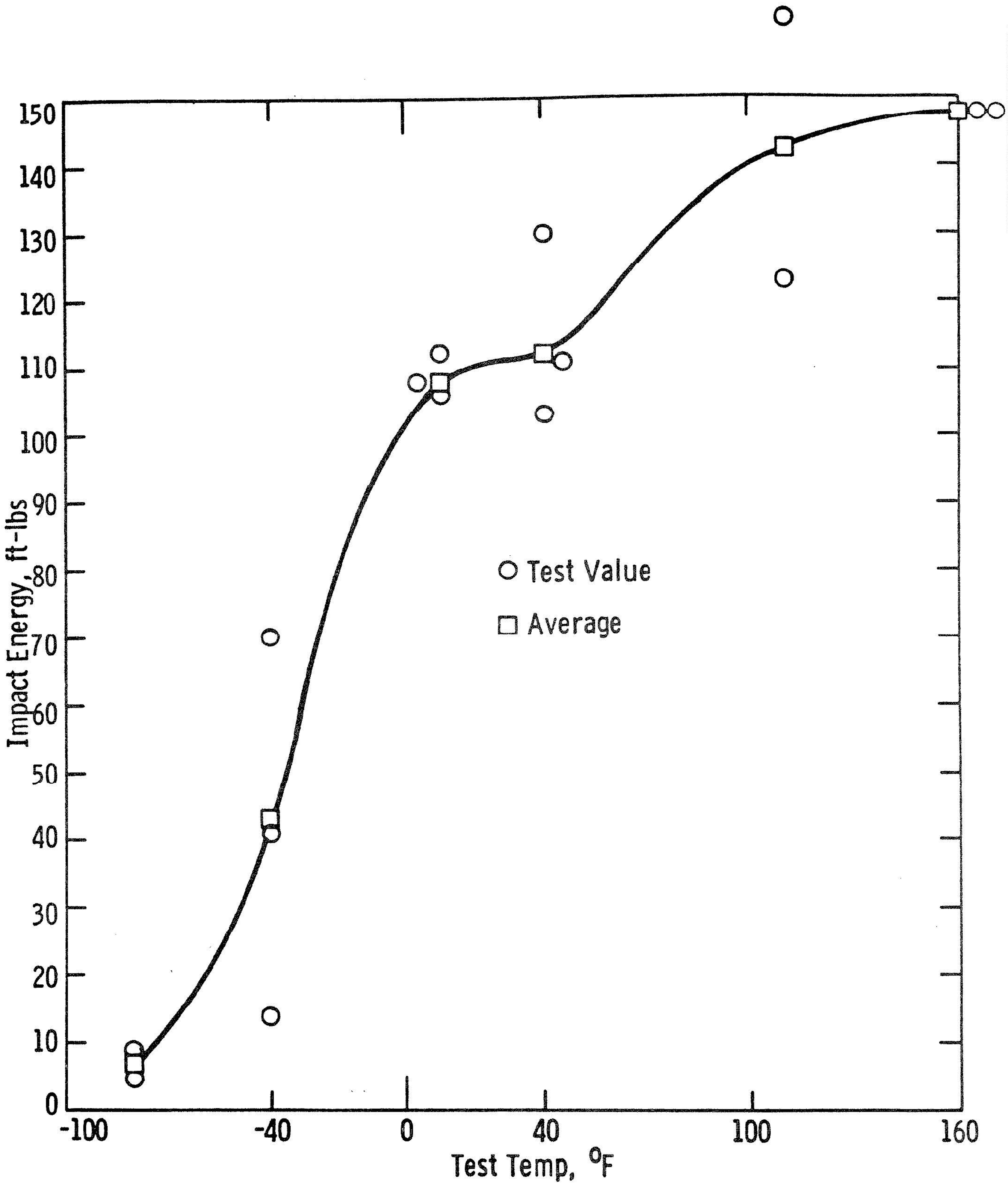

FLORIDA POWER & LIGHT CO.
St. Lucie Plant

Charpy V-Notch Impact Curve
Item Code C-9-1
Bottom Head

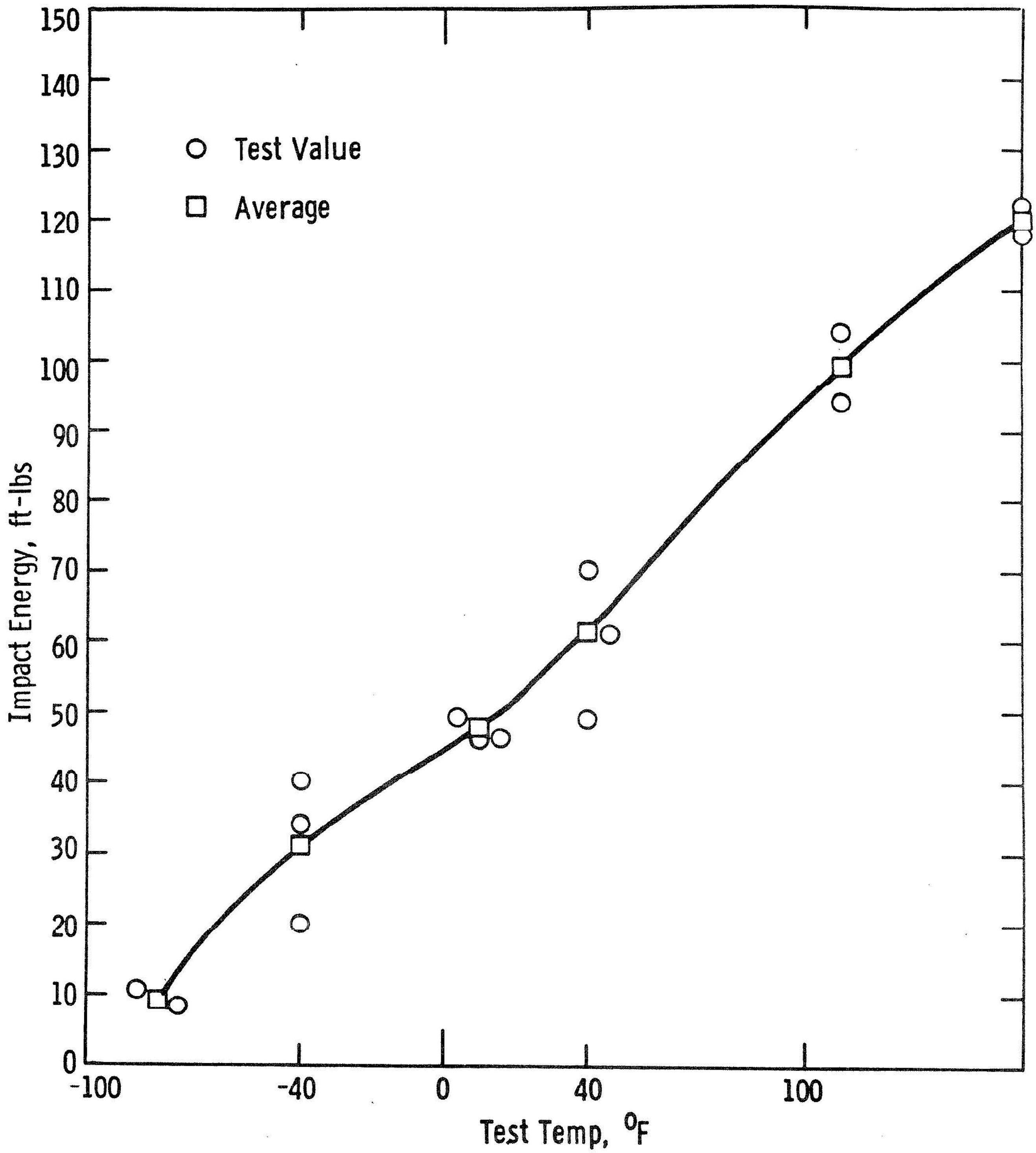
Figure 5.2-11



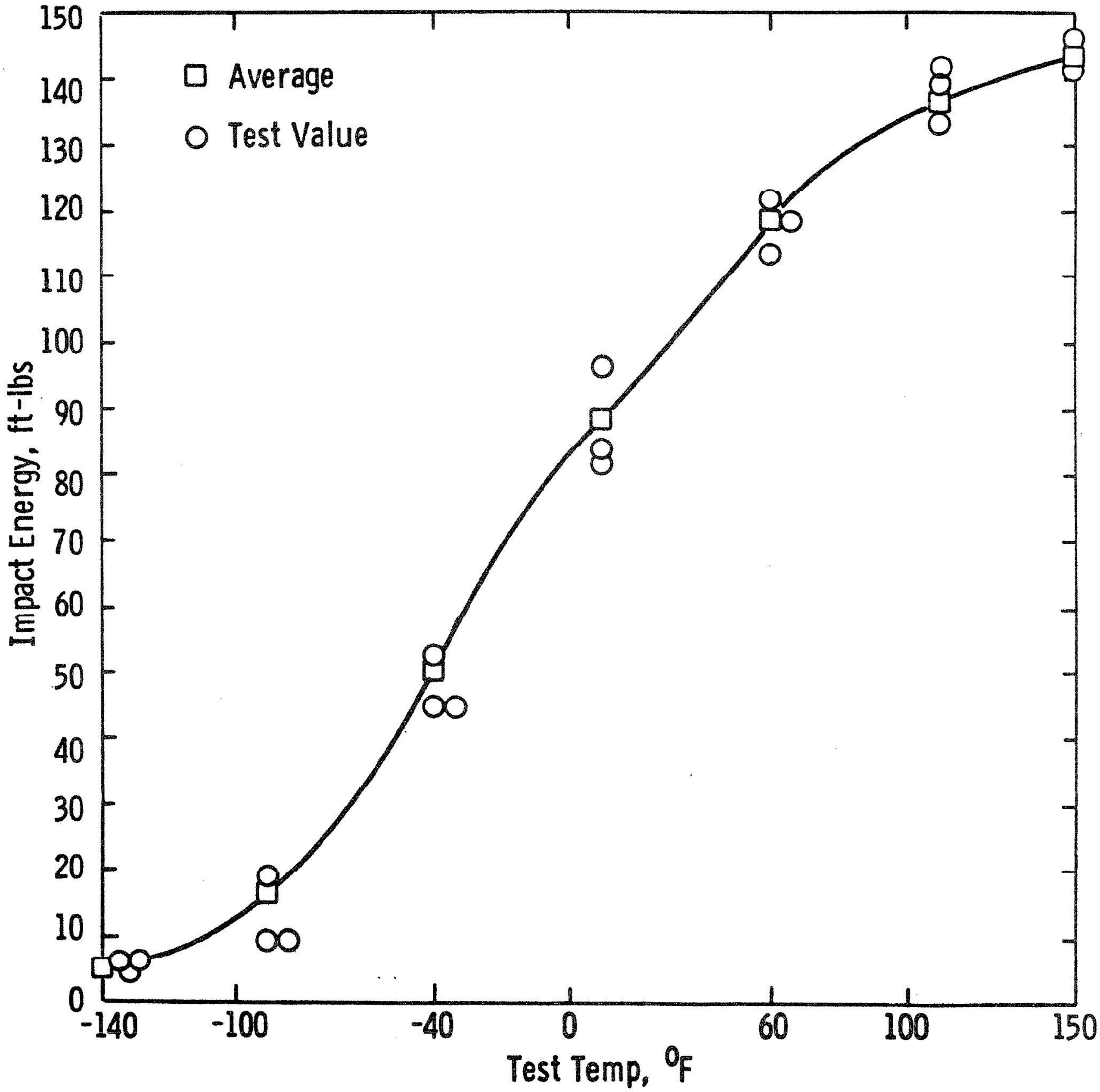

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-9-2<br>Bottom Head | Figure<br>5.2-12 |



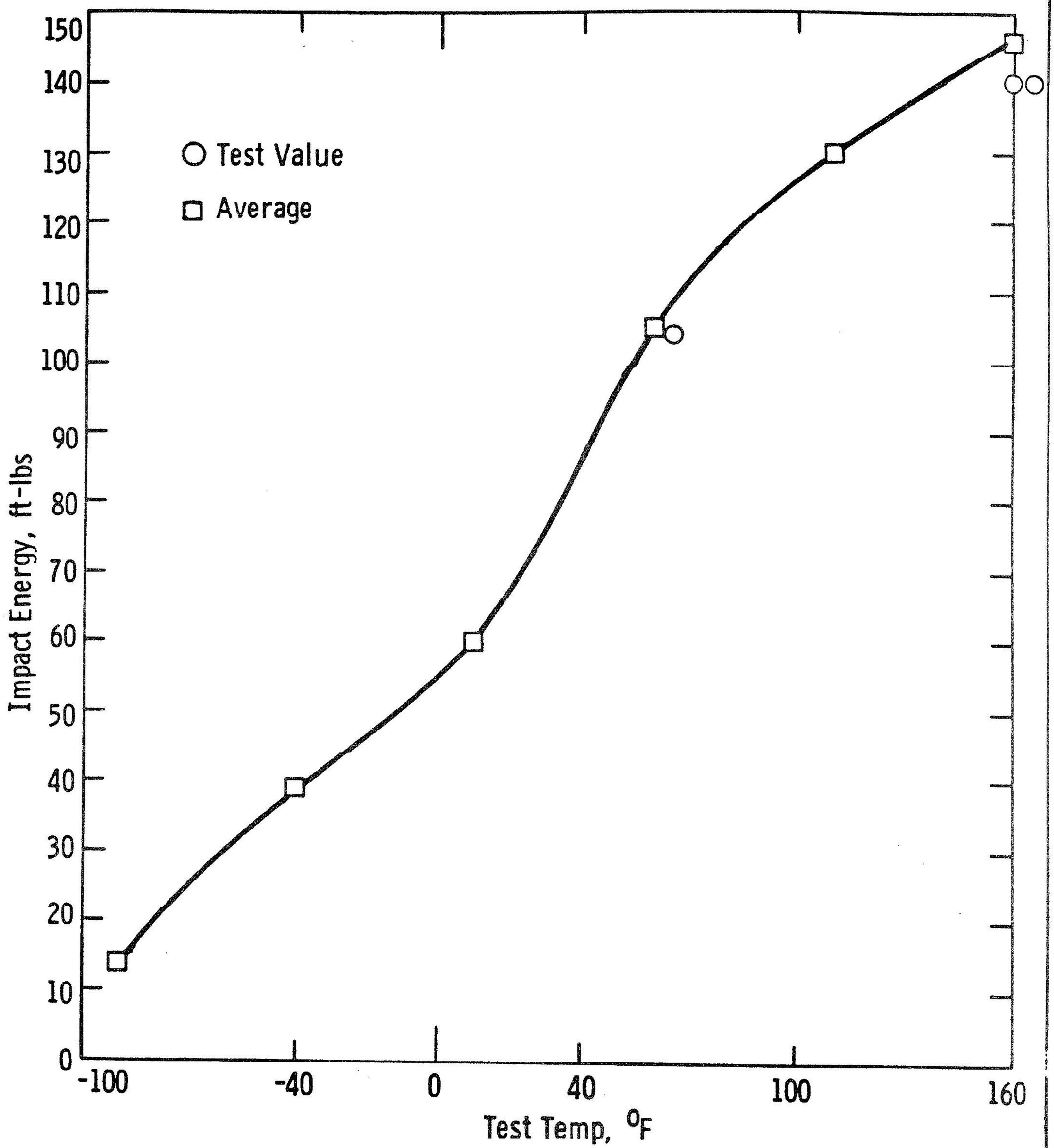

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve Item Code C-9-3 Bottom Head | Figure 5.2-13 |
|---|---|---|



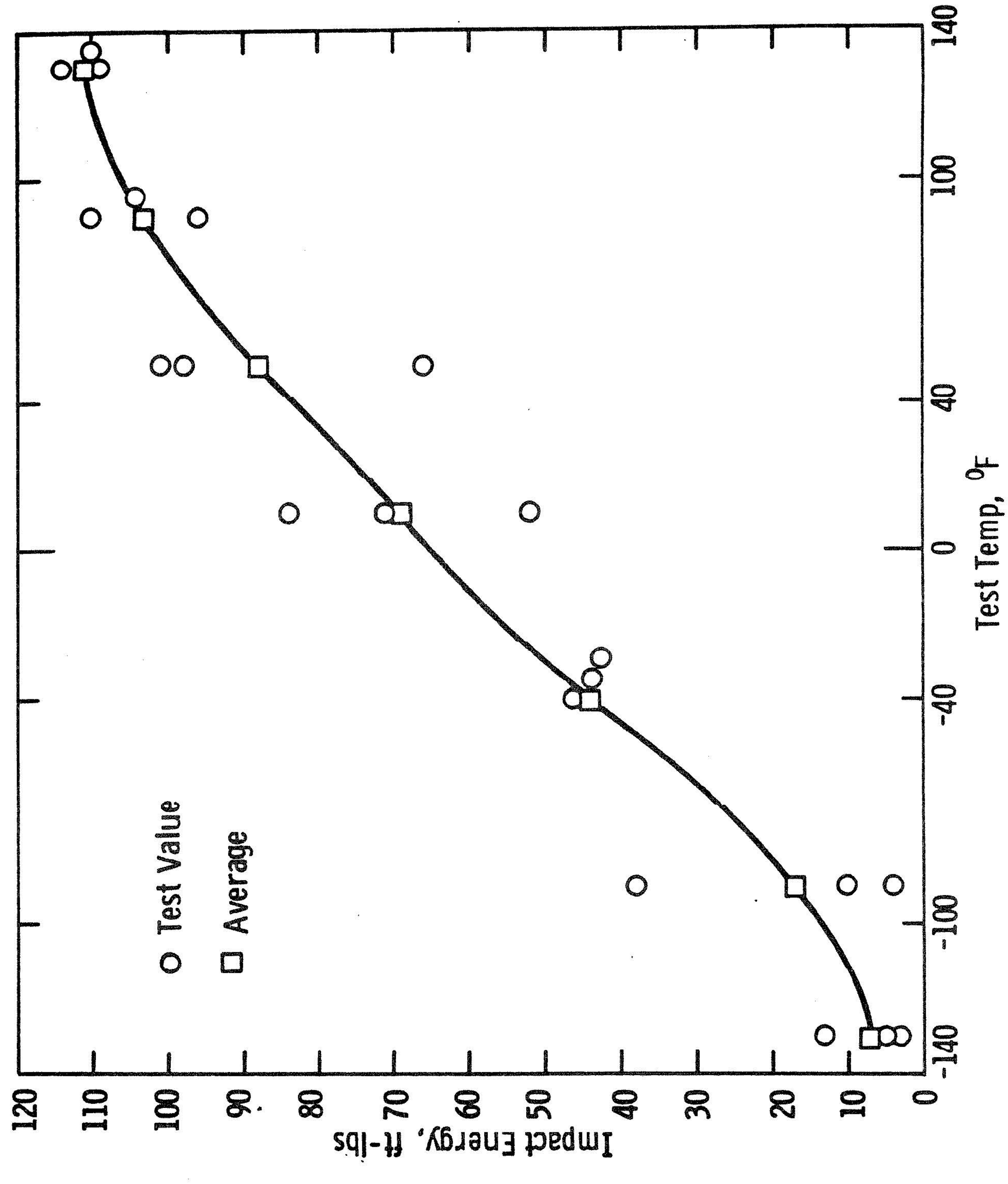

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-10-1<br>Bottom Head | Figure 5.2-14 |
|---|---|---|



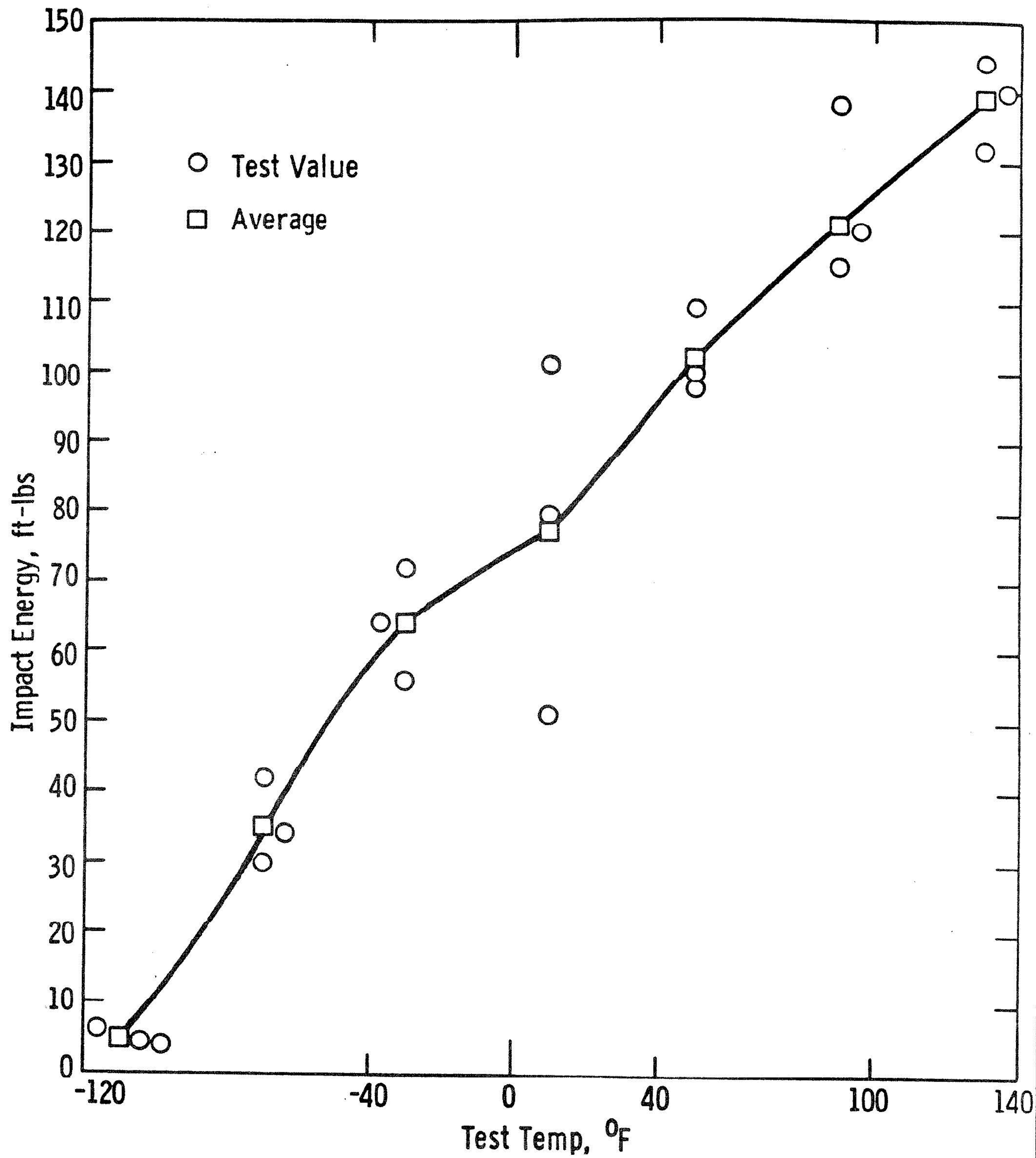

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-4-1<br>Inlet Nozzle | Figure 5.2-15 |
|---|---|---|



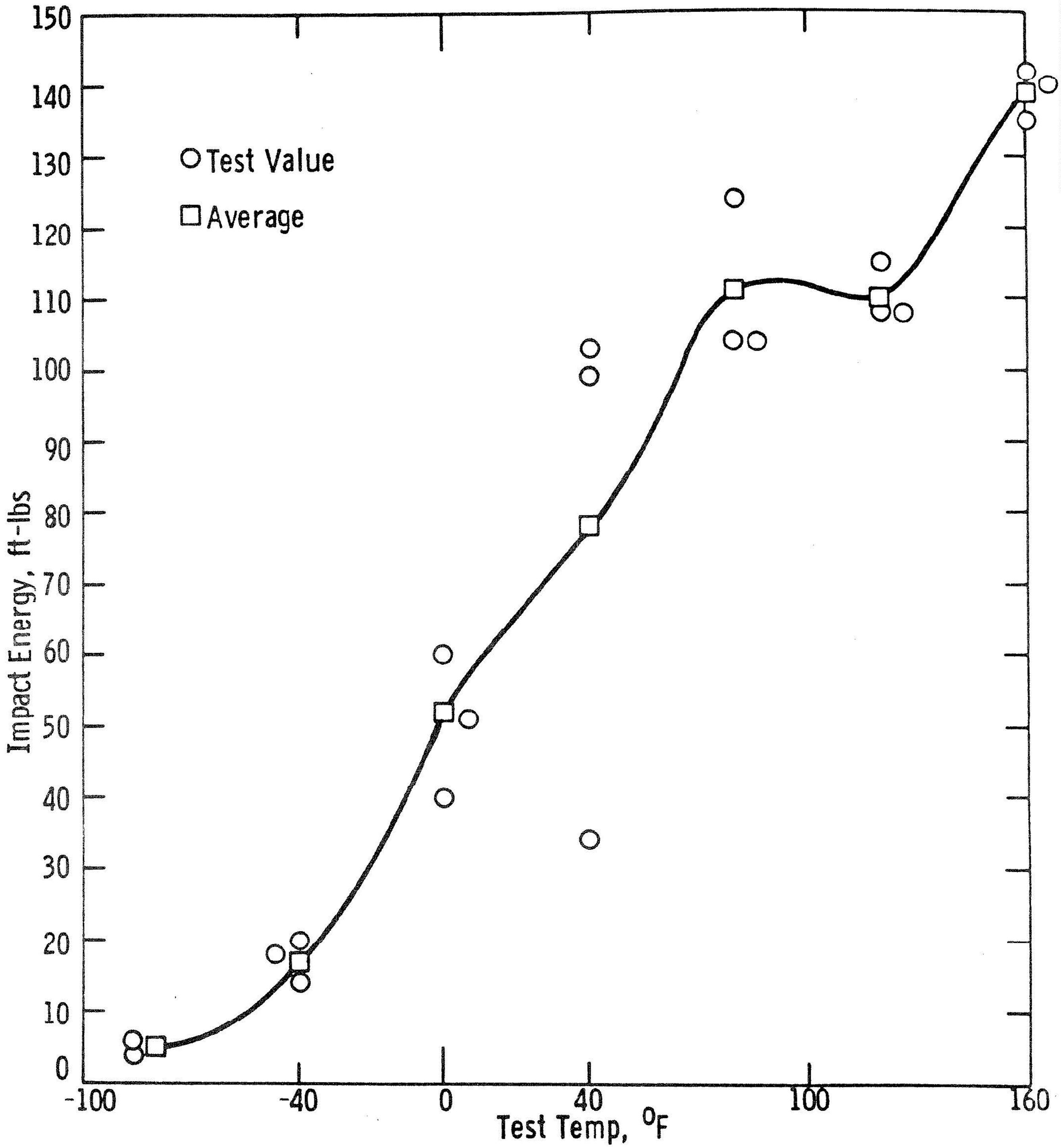

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve Item Code C-4-2 Inlet Nozzle | Figure 5.2-16 |
|---|---|---|



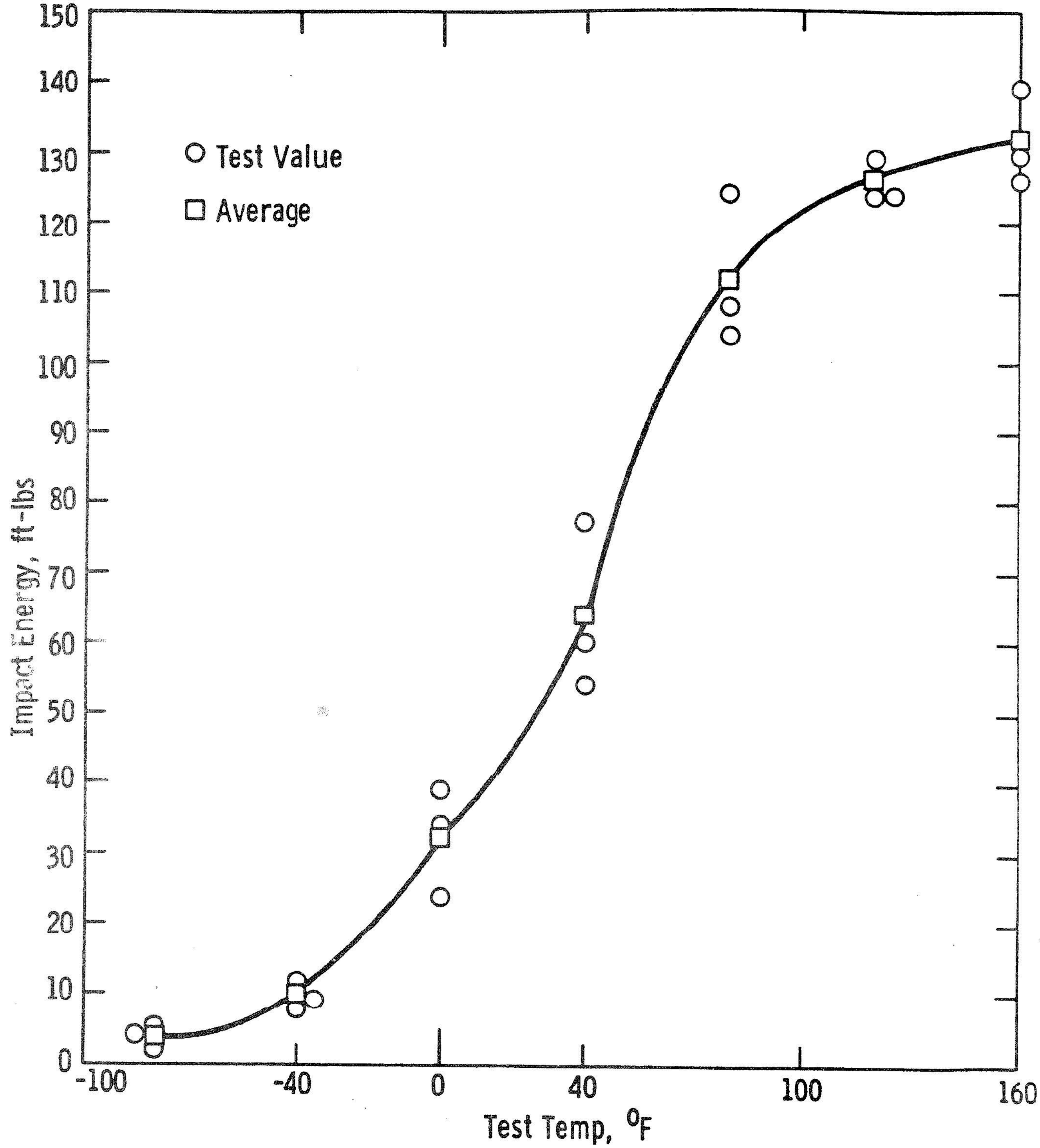

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-4-3<br>Inlet Nozzle | Figure<br>5.2-17 |



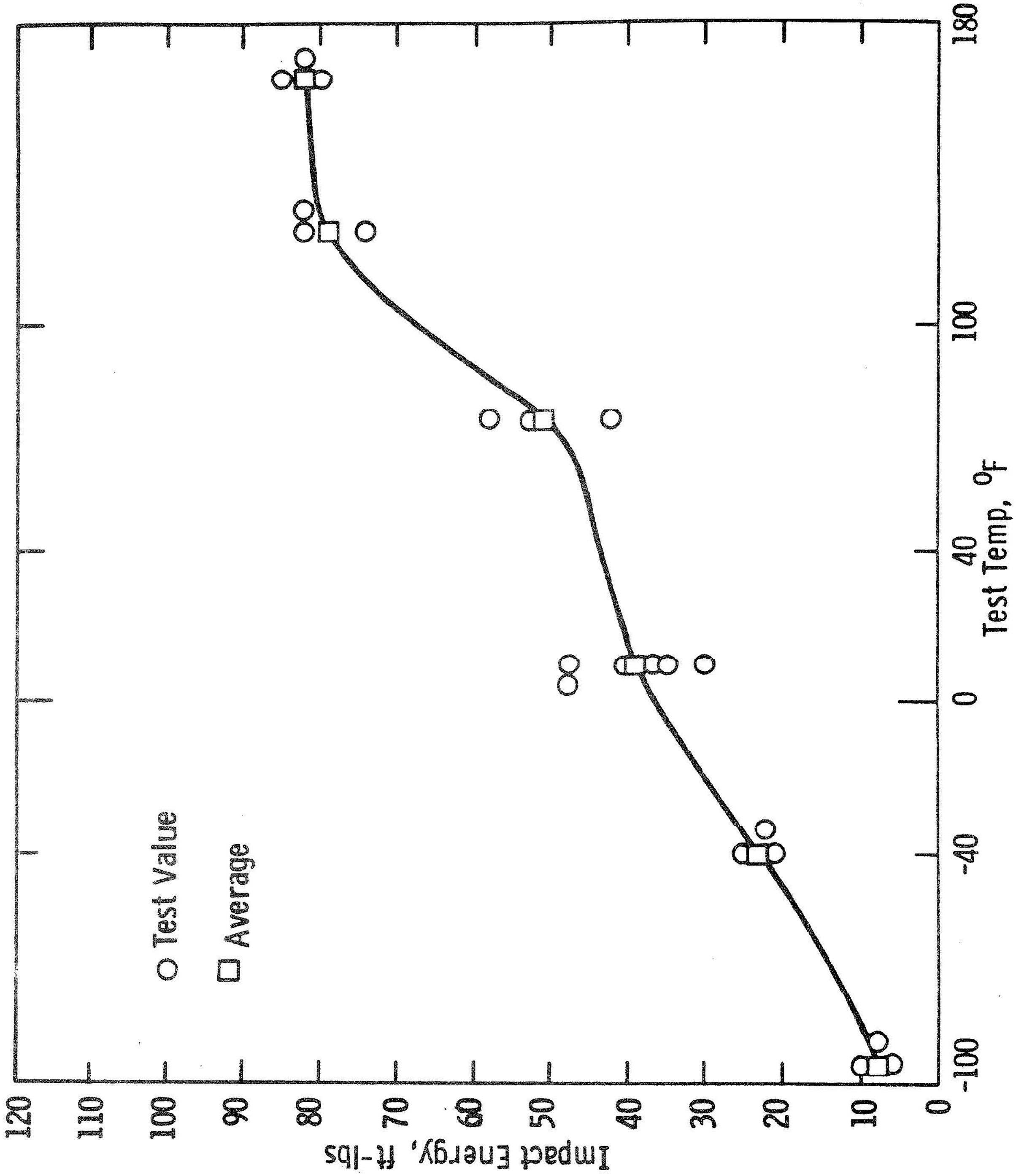

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-4-4<br>Inlet Nozzle | Figure<br>5.2-18 |




| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-16-1, 2, 3, 4<br>Inlet Nozzle Extension | Figure 5.2-19 |



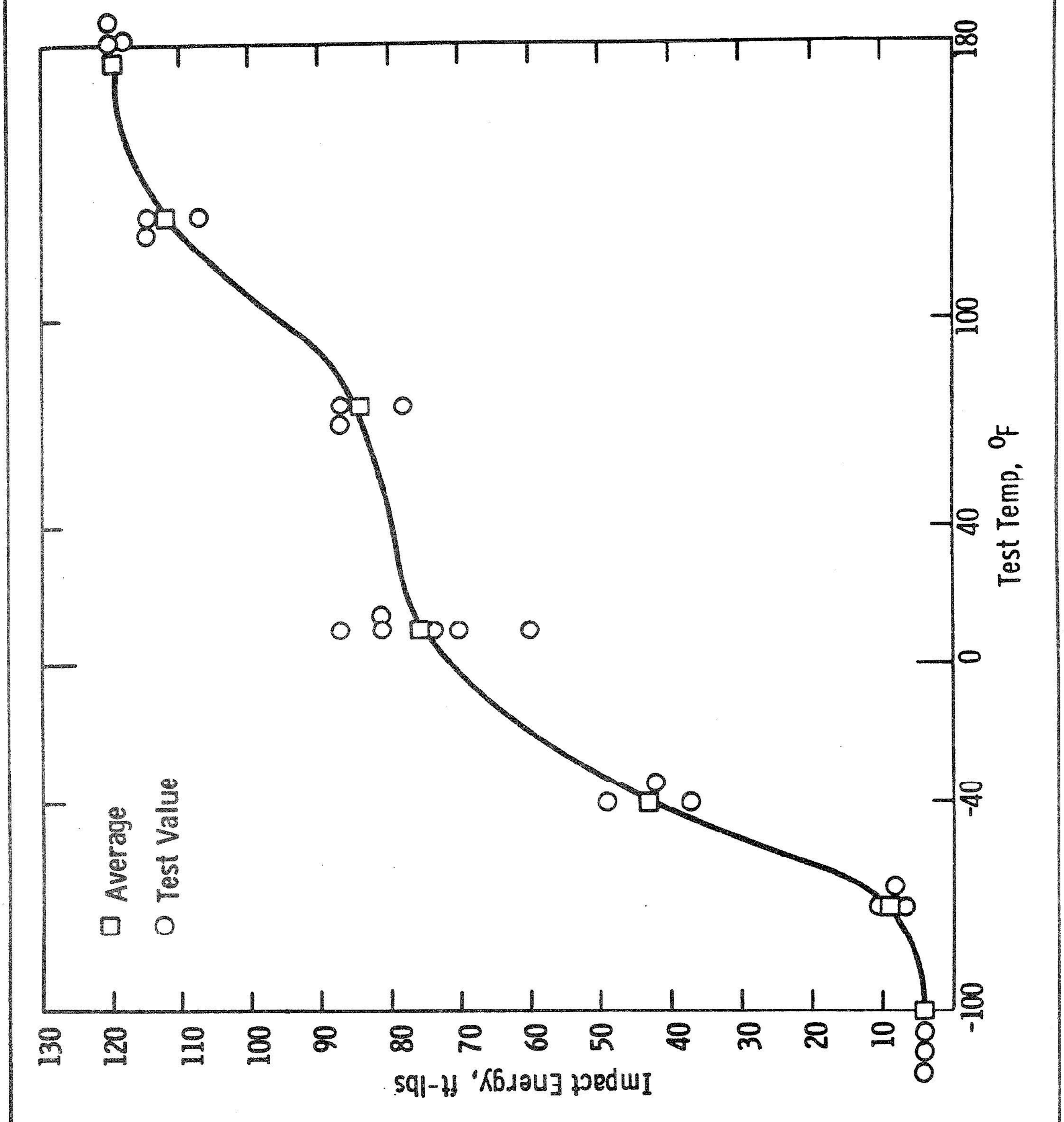

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve<br>Item Code C-17-1, 2<br>Outlet Nozzle Extension | Figure<br>5.2-20 |



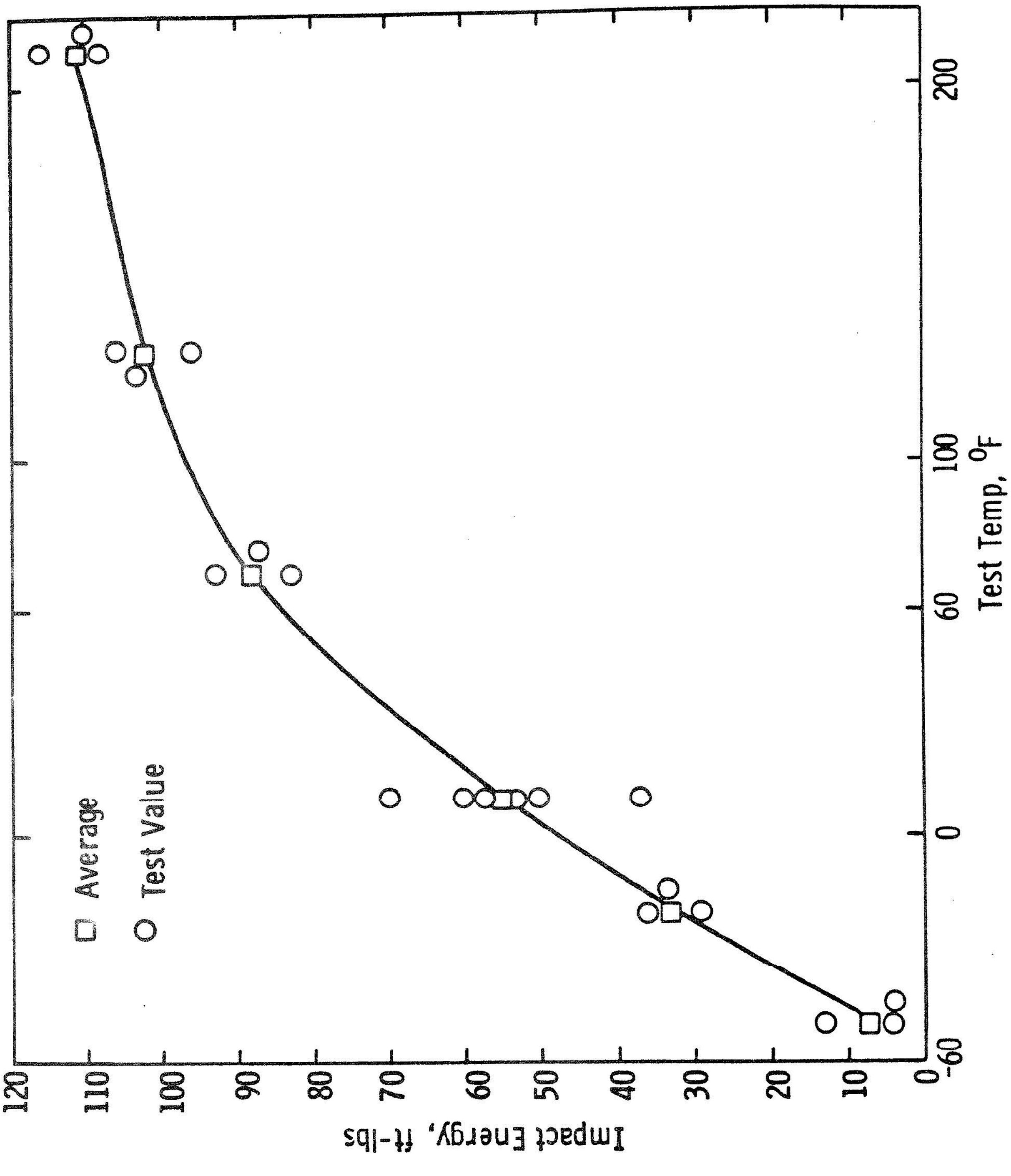

FLORIDA
POWER & LIGHT CO.
St. Lucie Plant

Charpy V-Notch Impact Curve
Item Code C-33-1, 2, 3
Vessel Support Forging

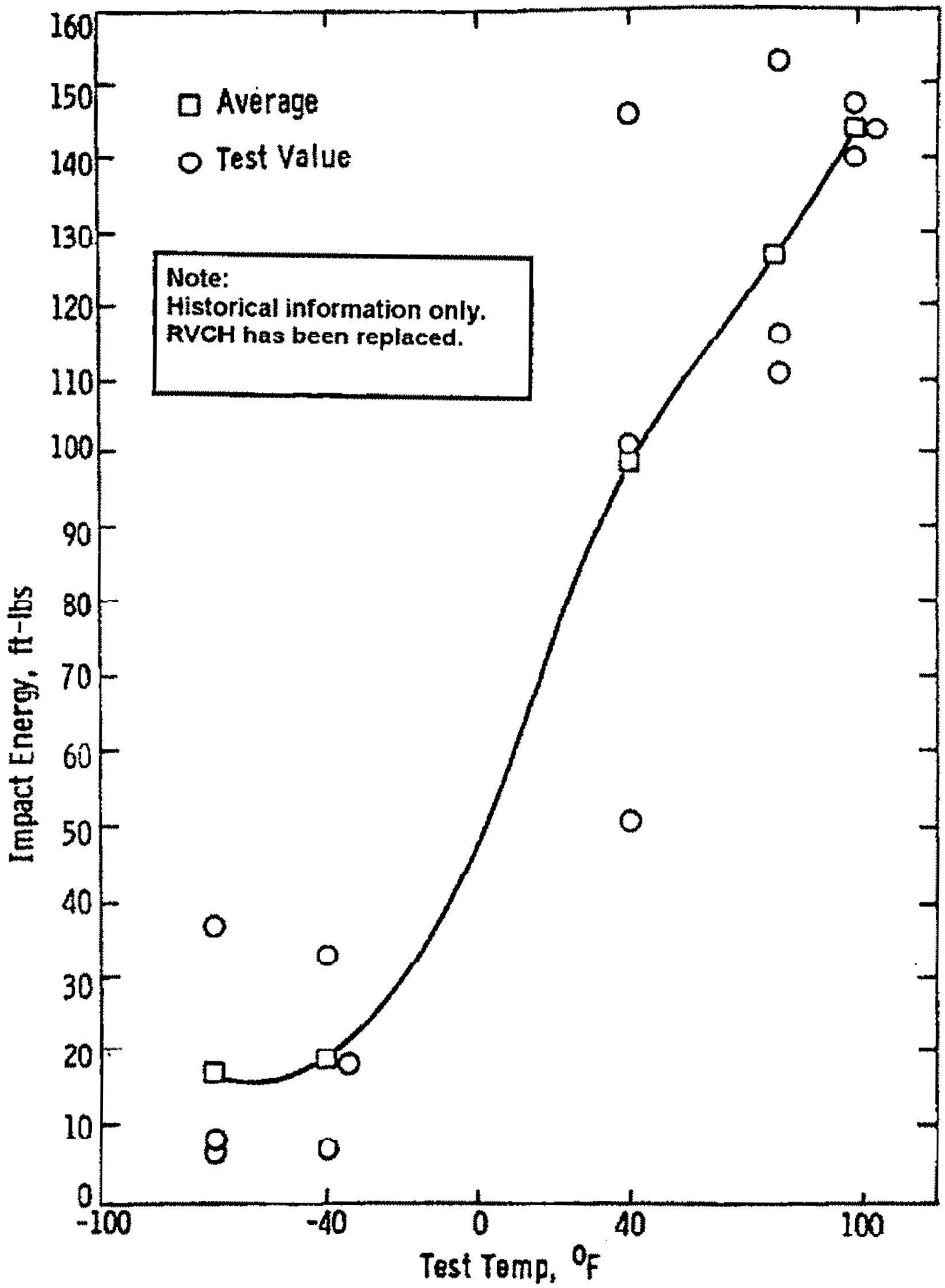
Figure
5.2-21




| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve Item Code C-3-1 Outlet Nozzle | Figure 5.2-22 |
|---|---|---|

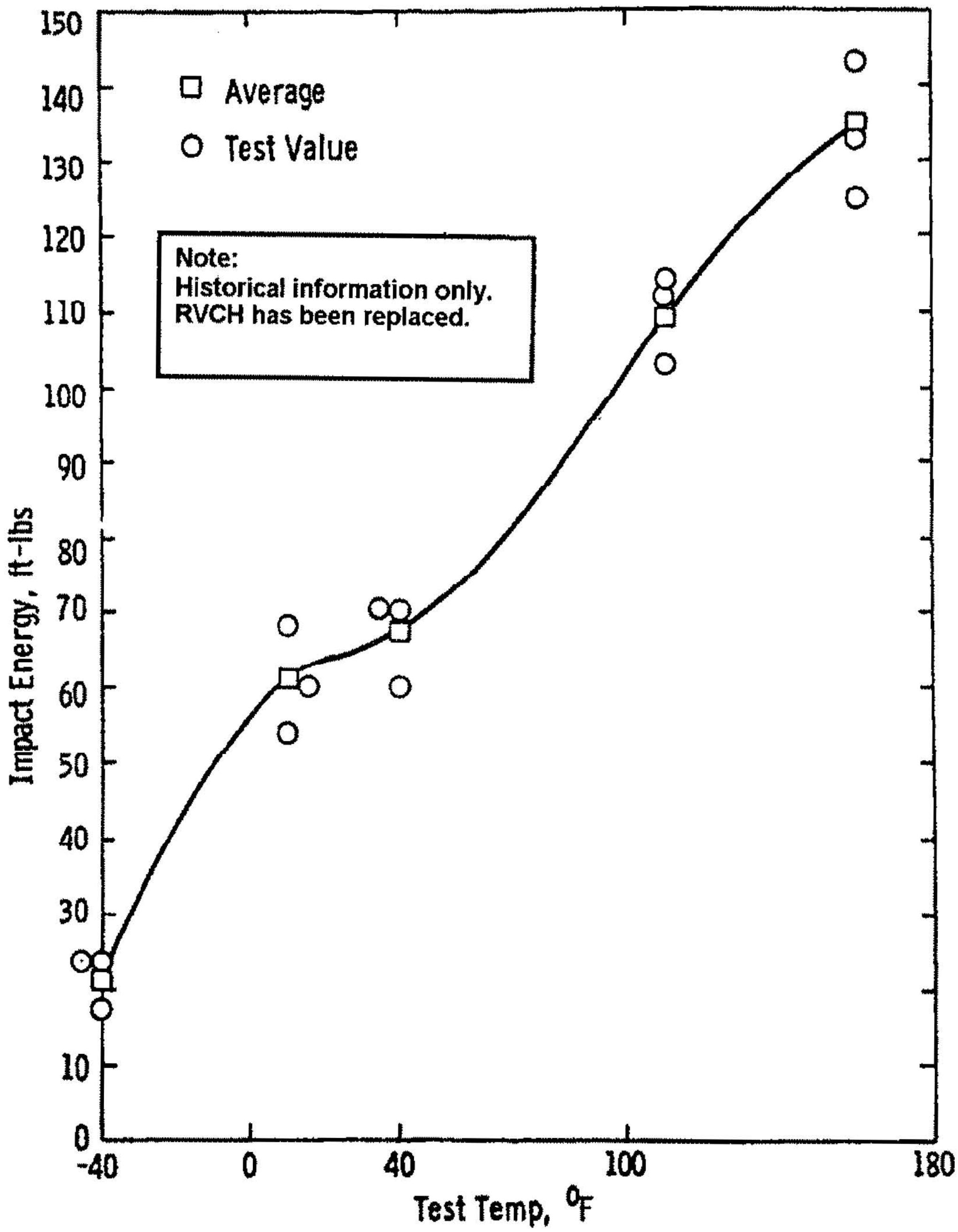



| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Charpy V-Notch Impact Curve Item Code C-3-2 Outlet Nozzle | Figure 5.2-23 |
|---|---|---|

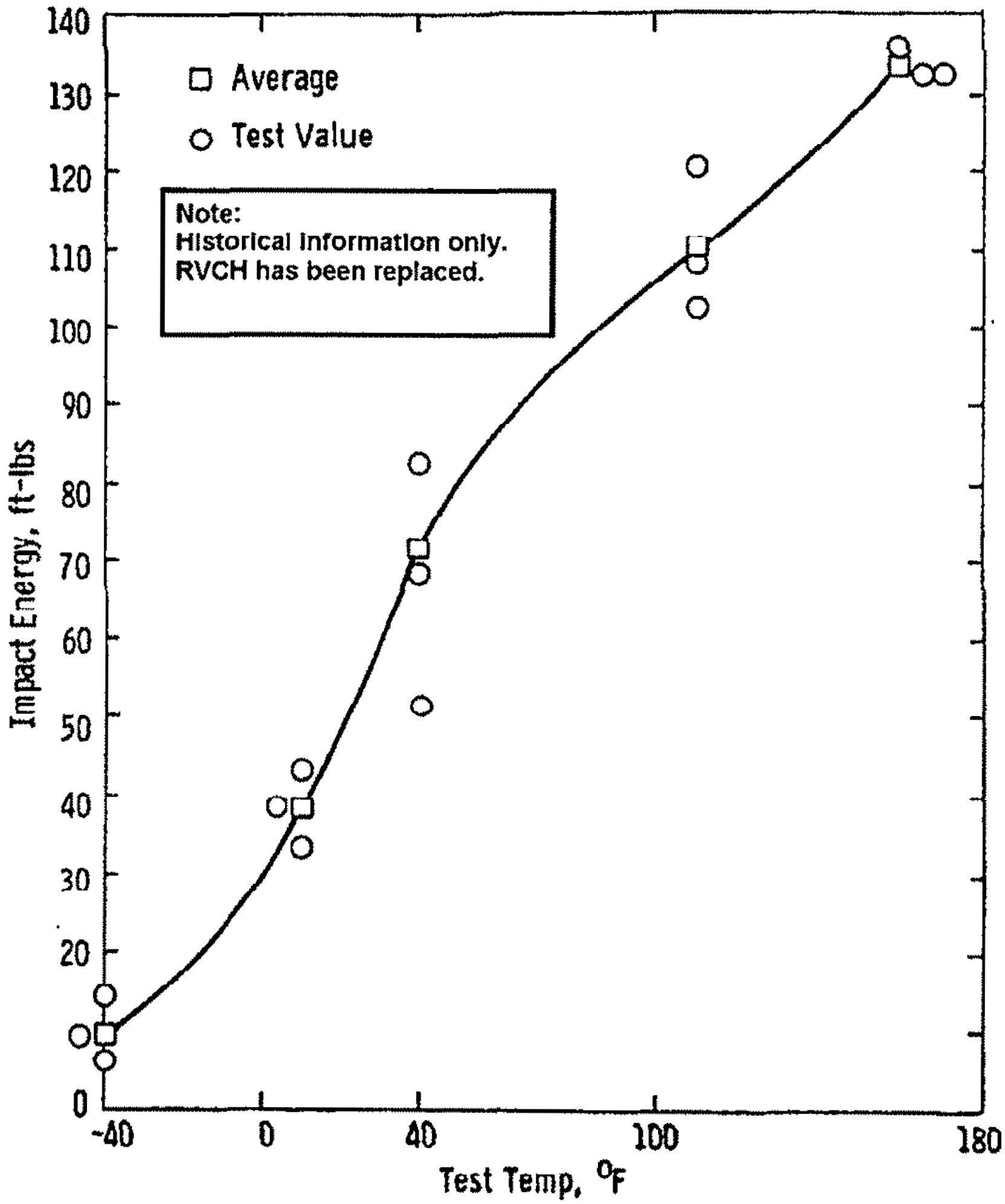



Florida Power & Light Company
St. Lucie Plant Unit 1

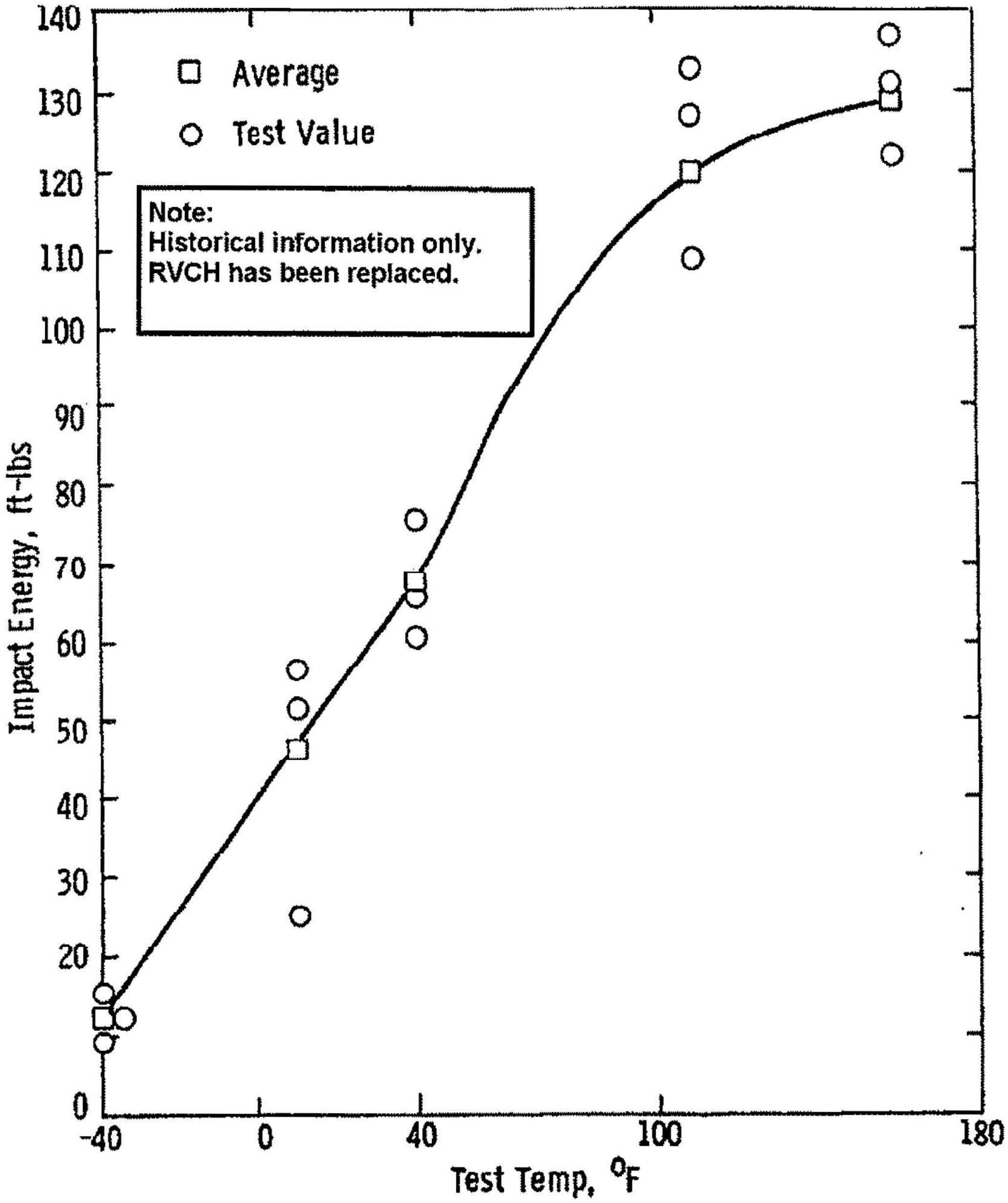
Charpy V-Notch Impact Curve
Item Code C-2
Closure Head Flange
Figure 5.2-24




| Florida Power & Light Company<br>St. Lucie Plant Unit 1 |
|---|
| Charpy V-Notch Impact Curve<br>Item Code C-21-1<br>Closure Head Torus<br>Figure 5.2-25 |

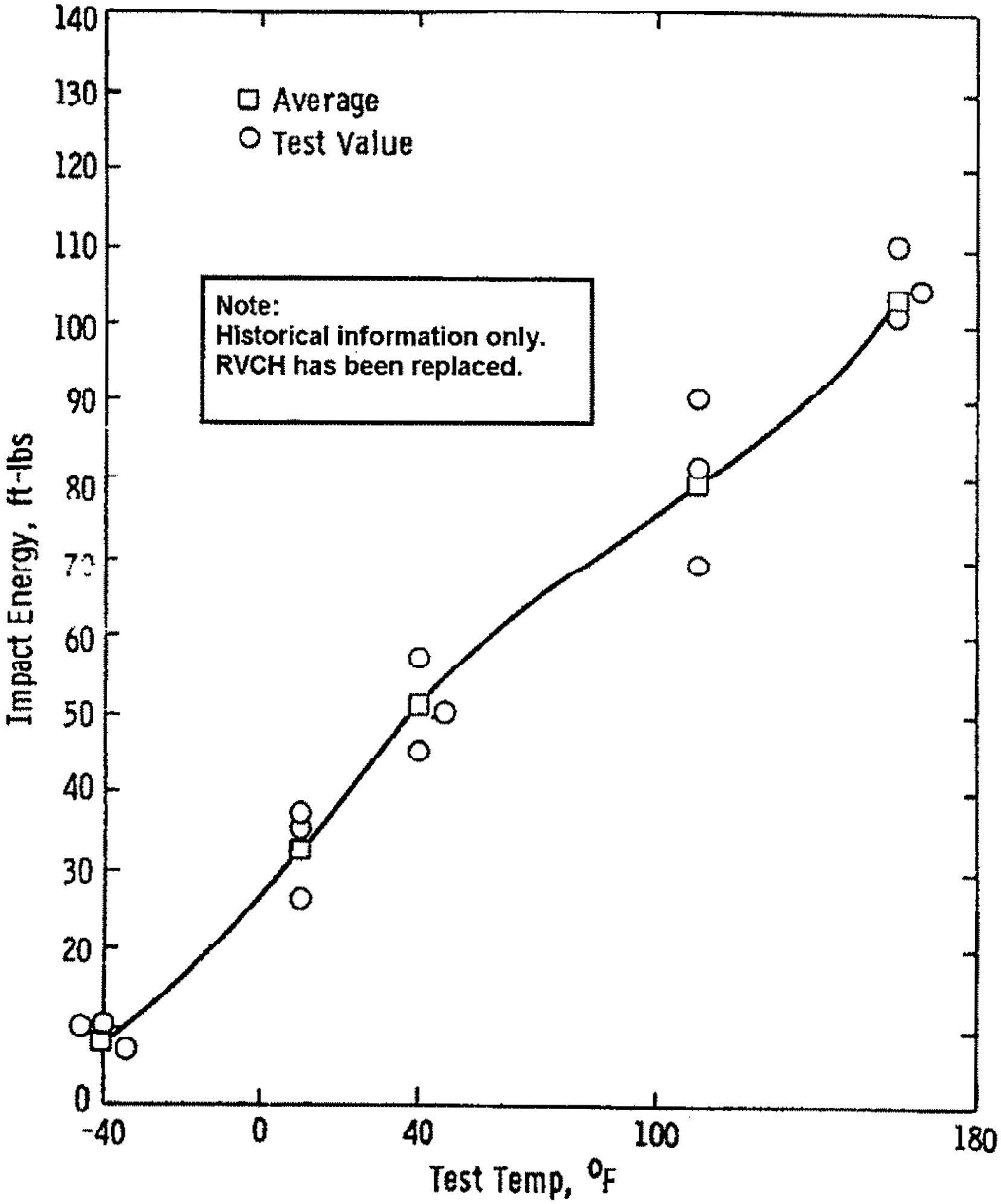



| |
|---|
| Florida Power & Light Company<br>St. Lucie Plant Unit 1 |
| Charpy V-Notch Impact Curve<br>Item Code C-21-2<br>Closure Head Torus<br>Figure 5.2-26 |




Florida Power & Light Company
St. Lucie Plant Unit 1

Charpy V-Notch Impact Curve
Item Code C-21-3
Closure Head Torus
Figure 5.2-27




| Florida Power & Light Company<br>St. Lucie Plant Unit 1 |
| --- |
| Charpy V-Notch Impact Curve<br>Item Code C-20-1<br>Closure Head Torus<br>Figure 5.2-28 |

## 5.3 THERMAL HYDRAULIC SYSTEM DESIGN

### 5.3.1 COMPONENT DESIGN

The reactor design described in Chapter 4 establishes hot and cold leg temperatures, minimum reactor coolant flow and maximum rector vessel pressure drop. The thermodynamic and hydrodynamic data are used in the design of the steam generator, reactor coolant pump, and reactor coolant piping. Reactor coolant system thermal hydraulic design data is given in Table 5.3-1. Figures 5.3-1 and 5.3-2 illustrate the reactor coolant system temperature control program and secondary pressure vs. power, respectively.

#### 5.3.1.1 Steam Generator

The steam generator is designed to transfer the design heat load from the reactor coolant side to secondary side and produce steam at the rated steam quality. The steam generator design is described in Section 5.5.1.

The steam generator reactor coolant side pressure drop is determined by summing the losses due to tube friction, tube bends, tube and nozzle contractions and expansions and steam generator inlet and outlet plenums.

#### 5.3.1.2 Reactor Coolant Pump

The design flow for the reactor coolant pump is determined from the reactor mass flow. The mass flow is converted to volumetric flow at the full power cold leg temperature to determine the pump design flow.

The maximum possible pressure loss at the design flow rate for the reactor vessel, steam generator, and piping is determined by adding an allowance for uncertainty on the best estimate of each pressure drop. These maximum values are used to establish the reactor coolant pump design head. The reactor coolant pump is designed to produce the minimum reactor design flow at the maximum expected system pressure loss. Pump performance characteristics are shown in Figure 5.5-10.

#### 5.3.1.3 Reactor Coolant Piping

The reactor coolant piping is designed to withstand the maximum expected reactor coolant pressure and temperature. The pipe is sized to provide reasonable fluid velocities which are below velocities which could cause significant erosion or cavitation.

### 5.3.2 ANALYTICAL METHOD

The predicted coolant flow rate through the reactor vessel for various combinations of pumps is listed in Table 5.3-2 together with maximum allowable power for each combination.

The flow rate through the reactor vessel is calculated by use of a computer code, called “COAST”. The “COAST” code analyzes reactor coolant flow under any combination of active and inactive pumps in a two-loop, four-pump plant. Momentum balances are performed on all of the flow paths. Frictional losses shock losses, the operating pump(s) head-flow characteristic curve and an experimentally derived reverse flow, locked rotor, loss coefficient for the nonoperating pump(s) are utilized in determining the unique flow distribution through the system.

### 5.3.3 REACTOR COOLANT PUMP NPSH REQUIREMENTS

The minimum reactor coolant system pressure at any given temperature is limited by the required net positive suction head (NPSH) for the reactor coolant pumps during portions of plant heatup and cooldown. Operating curves reflecting reactor coolant pump NPSH requirements are present in the Plant Emergency Operating Procedures.

The NPSH required versus pump flow is supplied by the pump vendor. Pump operation below this curve is prohibited. At low reactor coolant system temperatures and pressures, other considerations require the minimum pressure versus temperature curve be above the NPSH curve.

### 5.3.4 PART LOOP OPERATION

Plant design is to accommodate less than four pump flow during power operation, also known as part loop operation. Maximum power allowed at any given time then, is based on the percentage of total reactor coolant system (RCS) flowrate, with rated thermal power only allowed with maximum RCS flowrate (i.e., the amount delivered by four RCPs). Although part loop operation capability was part of the original plant design, including adjustable reactor protection system setpoints for low flow, high power, and thermal margin low pressure conditions, St. Lucie plant was never licensed for power operation with less than 100% (i.e., four RCP) flow.

### 5.3.5 NATURAL CIRCULATION CAPABILITY

The adequacy of natural circulation for decay heat removal after reactor shutdown has been verified analytically and by tests on the Palisades reactor (NRC Docket No. 50.255). The core $\Delta T$ in the analysis has been shown to be lower than the normal full power $\Delta T$. The thermal and mechanical loads on the core structure are less severe than normal design conditions.

On June 11, 1980 the reactor was shutdown due to a loss of component cooling water to the reactor coolant pumps with loss of RCP seal cooling a foremost concern. This required shutdown of the reactor coolant pumps and RCS cooldown by natural circulation. During the cooldown, abnormally rapid increases in pressurizer level were observed which could not be explained by the charging flow rate alone. Detailed evaluation and follow-up analyses indicated that a steam void probably formed in the upper head region of the reactor vessel which displaced water from the vessel into the pressurizer. Continued alternating realignment of charging flow between the cold legs and auxiliary spray line produced a “sawtooth” pressurizer level behavior as the reactor was brought to cold shutdown. See Reference 1.

This event provides dramatic evidence of the natural circulation cooldown capability of the reactor even with a voiding problem not previously considered.

Rapid refill and drain of the reactor vessel head during natural circulation cooldown is discussed in Section 5.4.2.

### 5.3.6 LOAD FOLLOWING AND TRANSIENT RESPONSE

Note: This Section contains information that is considered to be historical since the plant is not licensed to operate at power with less than 4 RCPs in operation.

The design features of the reactor coolant system influence its load following and transient response. The reactor coolant system is capable of following transients identified in Section 5.2.1. These requirements are considered when sizing the pressurizer to ensure adequate system pressure and inventory control. The pressurizer spray and heater capacities and control setpoints and the charging/letdown system control setpoints are selected through detailed computer simulation studies. In addition, the feedwater valve stroke speed and feedwater regulating system control setpoints are selected through computer analysis of these transients.

Finally, these transients are presented in the equipment specification for each reactor coolant system component to ensure the structural integrity of the system.

Plant load changes are initiated by adjustment of the turbine control system load reference setpoint which positions the turbine governor valves. The feedwater regulating system senses a change in steam flow and steam generator water level and through a three-element controller acts to restore water level to the programmed setpoint.

The pressurizer pressure and level control systems respond to changes caused by the expansion or contraction of the reactor coolant system water volume and actuate sprays, heaters, charging pumps or letdown valves as appropriate to maintain pressure and pressurizer level.

For operation with fewer than four reactor coolant pumps, the low flow, thermal margin and high power level trip setpoints are simultaneously changed to the allowable values for the selected pump condition by a normal switching arrangement in the low flow protective system (see Section 7.2). The normal procedure to increase the number of operating pumps is to reduce power, start the pump, advance the selector switch setting and increase core power. Analysis of the startup of an idle loop is described in Section 15.2.6.

A complete loss of flow initiates a reactor trip, and a partial loss of flow may initiate reactor trip in turn tripping the turbine. The steam dump and bypass system (Section 10.4.4) functions to remove the stored energy from the reactor coolant system, bringing the plant to the hot standby condition. Analysis of a loss of flow accidents using conservative assumptions, is presented in Section 15.2.5.

REFERENCES FOR SECTION 5.3


1. Letter R. E. Uhrig (FP&L) to Clark (NRC) Re: St. Lucie Unit 1 Docket No. 50-335, Natural Circulation Cooldown, L-80-431 dated 12/30/80.

TABLE 5.3-1
FULL POWER THERMAL AND HYDRAULIC CHARACTERISTICS

| | | |
|---|---|---|
| 1. | Reactor Vessel | |
| | NSSS Thermal Power, MWt | 3050* |
| | Design Pressure, psig | 2485 |
| | Operating Pressure at Outlet, psig | 2235 |
| | Coolant Outlet Temperature, F | 606.0 |
| | Coolant Inlet Temperature, F | 551.0 |
| | Coolant Outlet State | Subcooled |
| | Thermal Design Coolant Flow, $10^6$ lb/hr | 143.8 |
| 2. | Steam Generators | |
| | Number of Units | 2 |
| | Primary Side (or Tube Side) | |
| | Design Pressure/Temperature, psig/F | 2485/650 |

* RCP net heat input of 20 MWt and power measurement uncertainty included in thermal power.

TABLE 5.3-1 (Cont'd)

| | |
|---|---|
| Operating Pressure, psig | 2235 |
| Inlet Temperature, F | 601.7** |
| Outlet Temperature, F | 551.0** |
| Secondary or Shell Side | |
| Design Pressure/Temperature/ psig/F | 985/550 |
| Full Load Steam Pressure, psig | 850 upstream of nozzle** |
| Zero Load Steam Pressure, psig | 885 |
| Total Steam Flow per Gen., lb./hr. | $6.61 \times 10^6$ |
| Full Load Steam Quality, % | 99.90** |
| Feedwater Temperature, F | 436.2 |

3. Pressure Control System

| | |
|---|---|
| Pressurizer | |
| Design Pressure, psig | 2485 |
| Design Temperature, F | 700 |
| Operating Pressure, psig | 2235 |
| Operating Temperature, F | 653 |
| Internal Volume ft.$^3$ | 1500 |
| Heaters | |
| Type of Heaters | Immersion |
| Min. Required Heater Capacity, kw | 1375*** |
| Min. Required Number of Heaters | 110*** |

4. Reactor Coolant Pumps

| | |
|---|---|
| Number of Units | 4 |
| Type | Vert. – Cent. |
| Design Capacity, gpm | 92,500 |
| Design Pressure/Temperature, psig/F | 2485/650 |
| Operating Capacity | 109,625 |

*** A total of 125 kw can be removed from service, as described below:
No more than 2 proportional pressurizer heaters (25 kw), and;
No more than 8 backup pressurizer heaters (100 kw), with a maximum of 2 heaters in any one backup heater bank.

** Predicted – Replacement Steam Generators with 0% Plugging at EPU conditions.

| | |
|---|---|
| Operating Pressure, psig | 2235 |
| Total Dynamic Head, ft | 310 |
| Horsepower Rating, hp | 6500 |
| Pump Speed, (RPM) | 900 |
| 5. <u>Reactor Coolant Piping</u> | |
| Flow per Loop, $10^6$ lb/hr (Design Value) | 69.7 |
| Pipe Size, I.D., in | |
| Hot Leg | 42 |
| Cold Leg and Suction Leg | 30 |
| Surge Line | 9 3/8 |
| Spray Lines | 2 1/4 |
| Pipe Design Press./Temp., psig/F | 2485/650 |

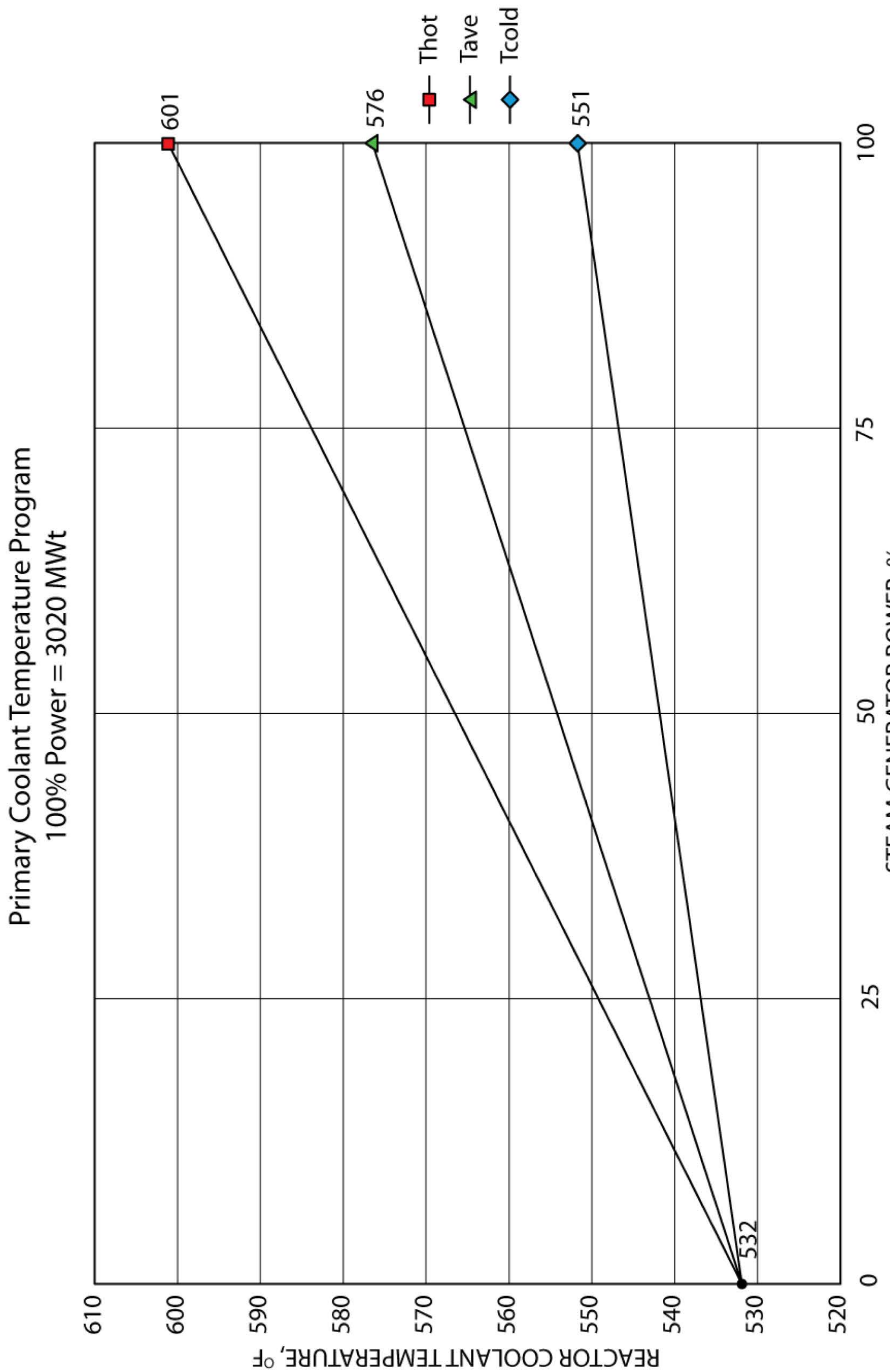
TABLE 5.3-2

REACTOR COOLANT FLOW FOR VARIOUS PUMP CONFIGURATIONS* **

| Pump Configuration | Calculated Vessel Flow Rate (lb/hr x $10^6$) | Max. Allowable Operating Reactor Power (Mwt) | Percentage Normal Total Flow | Percentage Reactor Operating Power |
|---|---|---|---|---|
| Normal Four-Pump Operation | 139.4 | 2710 | 100 | 100 |
| Three-Pump Operation | 107.6 | 2032.5 | 77.2 | 75 |
| Two-Pump Operation, One Pump in Each Loop, Diametrically Opposed or Adjacent Inlet Nozzles | 73.9 | 1300.8 | 53.0 | 48 |
| Two-Pump Operation, Both On Same Steam Generator | 69.3 | 1192.4 | 49.7 | 44 |

*The Technical Specifications currently do not allow operation with less than all four reactors coolant pumps running.

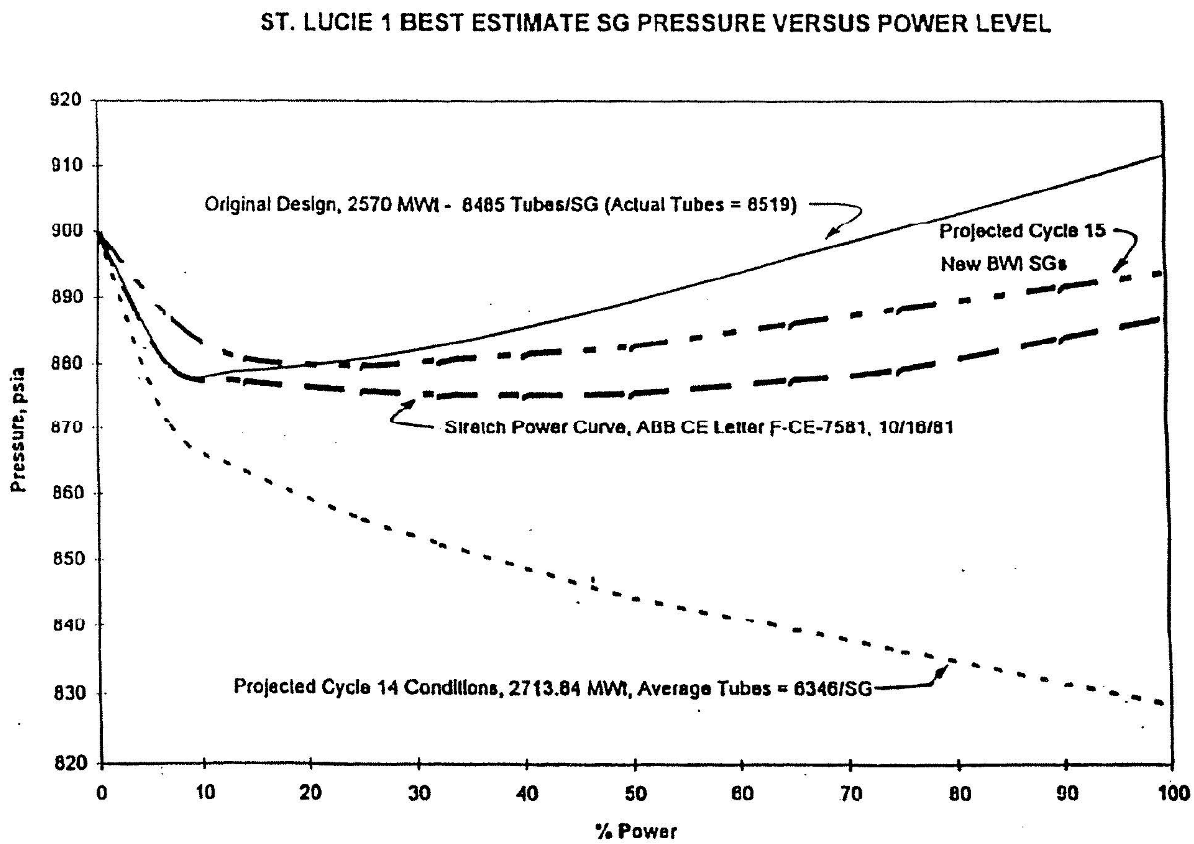
**Design data not accounting for S/G tube plugging and replacement steam generators.




Amendment No. 26 (11/13)

FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

**COOLANT TEMPERATURE PROGRAM**
**FIGURE 5.3-1**




Amendment No. 16, (1/98)

| |
|---|
| FLORIDA POWER & LIGHT COMPANY<br>**ST. LUCIE PLANT UNIT 1** |
| SECONDARY PRESSURE PROGRAM<br><br>**FIGURE 5.3-2** |

## 5.4 REACTOR VESSEL AND APPURTENANCES

### 5.4.1 REACTOR VESSEL DESCRIPTION

The reactor vessel (Figure 5.4-1) integral supports consist of three pads welded to the underside of one outlet and two inlet reactor vessel nozzles, in turn supported by graphite lubricate bearing plates. The arrangement of the vessel supports, allows radial growth of the reactor vessel due to thermal expansion while maintaining it centered and restrained from movement caused by seismic disturbances. Departure from levelness of not more than 0.002 inch per foot of flange diameter is maintained during construction to facilitate proper assembly of reactor internals. The design parameters for the reactor vessel are given in Table 5.4-1. The vessel bottom heads, cylindrical shell courses and head lifting lugs are made of SA 533-65, Grade B, Class I material. The vessel top head is made from a one piece forging of SA-508 Class 3 material.

The vessel closure flange is a forged ring with a machined ledge on the inside surface to support the reactor internals. No ring forgings are used for reactor vessel shell sections. The flange is drilled and tapped to receive the closure studs and is machined to provide a mating surface for the reactor vessel closure seal. The vessel closure contains 54 studs, 7 inches in diameter, with eight threads per inch. The stud material is Parkerized ASTM A-540, Grade B24, with a specified minimum yield strength of 130,000 psi. Test results on the material used for these studs demonstrates a minimum yield strength not less than 141,000 psi at 78F. The tensile stress in each stud when elongated for operational conditions is approximately 40 ksi.

Six radial nozzles on a common plane are located just below the vessel closure flange. Extra thickness in this vessel-nozzle course provides the reinforcement required for the nozzles. Additional reinforcement is provided for the individual nozzle attachments. A boss located around each outlet nozzle on the inside diameter of the vessel wall provides a mating surface for the internal structure which guides the outlet coolant flow. This boss and the outlet sleeve on the core support barrel are machined to a common contour to minimize core bypass leakage. A hemispherical head forms the lower end of the vessel shell. There are no penetrations in the lower head.

The removable top closure head is hemispherical. The head flange is drilled to match the vessel flange stud bolt locations. The 54 stud bolts are fitted with spherical crowned washers located between the closure nuts and head flange, to maintain stud alignment during head flexing due to boltup. To ensure uniform loading of the closure seal the studs are hydraulically bolt-tensioned.

A detailed analysis has been performed which shows that 36 evenly distributed studs can fail before the remaining stud stresses reach yield and the closure separates at design pressure, and that 16 adjacent studs can fail before the closure will fail by "zippering".

Flange sealing is accomplished by a double-seal arrangement utilizing two silver jacketed Ni-Cr-Fe alloy, spring-energized O-ring seals. The space between the two rings is monitored (see Section 5.2.4.5) to allow detection of any inner ring leakage. The control element drive mechanism nozzles terminate with threaded and canopy seal-welded ends at the top. There are eight instrumentation nozzles with mechanical seal connections. In addition to these nozzles there is a 3/4 inch vent connection utilized by the Reactor Coolant Gas Vent System (RCGVS). See Section 5.7.

The core is supported from an internally machined core support ledge. The control element drive mechanisms are supported by the nozzles in the reactor vessel head.

### 5.4.2 HEATUP AND COOLDOWN LIMITS

The reactor vessel is designed for the transients listed in Section 5.2.1. Administrative procedures ensure that the Technical Specification pressure/temperature limits for heatup and cooldown of the vessel are not exceeded. Heatup, cooldown and hydrostatic test pressure/temperature limits have been calculated in accordance with ASME Boiler and Pressure Vessel Code Section III, Appendix G to the 2002 Edition with the 2003 Addenda, with the following exception. The NRC has approved a plant-specific exemption from 10 CFR 50, Appendix G requirements to allow use of the methodology of CE-NPSD-683-A (Reference 15) to generate Pressure-Temperature limits. The heatup, cooldown and system hydrotest pressure/temperature limit curves are based on the requirement in Appendix G of 10 CFR Part 50 that in no case when the core is critical, other than for the purpose of low-power level physics tests, will the temperature of the reactor vessel be made lower than the minimum permissible temperature for the in-service system hydrostatic pressure test nor less than 40°F above that temperature required by Section IV.A.2 of Appendix G of 10 CFR 50. The value of predicated adjusted reference temperature ($RT_{NDT}$) used to calculate the pressure/temperature limit curves was based on the most limiting vessel material at the end of the applicable service period. Reactor operations and the resultant irradiation will cause a shift in the $RT_{NDT}$ of the reactor vessel materials adjacent to the core, which results in the vessel beltline materials becoming limiting after initial operation. The actual shift in $RT_{NDT}$ of the vessel materials will benchmarked periodically during operation by removing and evaluating the reactor vessel surveillance capsule specimens described in Section 5.4.4. The results of these surveillance capsule specimens are evaluated to determine if new pressure/temperature limit curves are required in accordance with 10 CFR 50, Appendices G and H.

Rapid refill and drain of the reactor vessel head during natural circulation cooldown has been analyzed by the vendor with the result that stresses do not exceed those occurring during a normal cooldown of 100°F per hour. See Reference 1. This analysis was not performed for the EPU, however, the text is retained for historical purposes.

Analyses of natural circulation cooldown events have been performed to determine the time needed for the upper head to cool to a temperature that will prevent void formation upon depressurization and how much condensate is required to achieve that condition. See Reference 2 and Appendix 5C. The appropriate operating procedures reflect the results of these analyses.

### 5.4.3 REACTOR VESSEL FRACTURE TOUGHNESS

Based upon the concern over reactor vessel embrittlement and pressurized thermal shock and the requirement indicated in 10 CFR 50.61 (b) (1), projected values of RT (PTS) for 54 effective full power years have been calculated for St. Lucie Unit 1.

It is concluded that St. Lucie Unit 1 could safely operate without restriction from PTS considerations. The maximum RT (PTS) will be experienced by the lower shell longitudinal seams at the termination of the plant operating license. The RT (PTS) value for this limiting material at end of license (EOL) is less than the screening criterion of 270°F for longitudinal welds. The current EOL RT (PTS) results for all the beltline materials are maintained in the NRC Docket under 10 CFR 50.61 for the unit.

The St. Lucie Unit 1 reactor pressure vessel beltline, as defined by 10 CFR 50, Appendix H, consists of the six plates used to form the lower and intermediate shell courses in the vessel, the included longitudinal seam welds and the lower to intermediate shell girth seam weld. The plates were manufactured from SA533 Grade B Class 1 quenched and tempered plate. The heat treatment consisted of austenization at 1600 ± 50°F for four hours, water quenching and tempering at 1225 ± 25°F for four hours. The ASME Code qualification test plates were stress relieved at 1150 ± 25°F for forty hours, and furnace cooled to 600°F. The longitudinal and girth seam welds were fabricated using E8018-C3 manual arc electrodes and Mil B-4 submerged arc weld wire with Linde 124, 0091 and 1092 flux. The post weld heat treatment consisted of a forty hour 1150 ± 25°F stress relief heat treatment followed by furnace cooling to 600°F. The beltline materials are identified in Tables 5.4-7 through 5.4-8. Copper, Nickel and initial RT NDT are listed in these tables.

## 5.4.4 MATERIAL SURVEILLANCE PROGRAM

The material surveillance program is implemented to monitor the radiation-induced changes in the mechanical and impact properties of the reactor vessel materials (base metal, weld metal and heat-affected-zone metal.) Changes in the impact properties of the materials are evaluated by the comparison of pre-irradiation (Reference 6) and post-irradiation Charpy impact test specimens. Changes in mechanical properties are evaluated by the comparison of pre-irradiation and post-irradiation data from tensile test specimens.

The surveillance program (Reference 5) described herein satisfies the intent of the proposed Appendix H 10 CFR Part 50 as published in the Federal Register on July 3, 1971.

The differences between the plant surveillance program and the requirements presented in Appendix H are the following:

a) Appendix H, Section II A - Sample Materials

The weldments for the weld metal samples and heat-affected-zone (HAZ) samples are prepared in a reactor vessel girth seam weld rather than being an extension of a longitudinal seam weld. Following the same procedures as used for the reactor vessel welds and the use of the same lots/heats of filler wire, rod and flux, this sample weldment is representative of the girth seam weld which passes through the areas of highest radiation flux in the core region of the reactor vessel.

b) Appendix H, Section II B - Attachments to Reactor Vessel

In adhering to the requirement of placing the surveillance specimens as close as possible to the reactor vessel wall, the capsule holders are attached to the cladding of the reactor vessel and are not major load bearing components. By such placement, temperature, flux spectrum, and fluence differences between the surveillance specimens and the reactor vessel are minimized, thereby permitting more accurate assessment of the changes in the reactor vessel properties.

c) Appendix H, Section II B - Capsule Replacements

The surveillance capsule holders will permit installation of replacement capsule assemblies during those shutdown periods when the reactor internals are removed.

d) Appendix H, Section II A - Specimen Orientation

Charpy impact specimens of base metal oriented in the strong (RW) direction are included in each surveillance capsule assembly. Similar specimens oriented in the weak (WR) direction are included in 4 of the 6 capsule assemblies. The unirradiated baseline properties will be thoroughly established for both the strong (RW) and weak (WR) directions permitting RW/WR correlations to be established.

Sufficient quantities of WR oriented base metal specimens are included in the program to adequately verify the unirradiated RW/WR correlations after irradiation. In this way the weak (WR) direction properties of the irradiated plate materials in the reactor vessel can be established.

Three metallurgically different materials representative of the reactor vessel are investigated. These are base metal, weld metal, and weld heat-affected-zone (HAZ) material. In addition to the materials from the reactor vessel, materials from a standard heat of SA533B, made available through the Heavy Section Steel Technology (HSST) Program, are also used. This reference material is fully processed and heat treated and is used for Charpy impact specimens so that a comparison may be made between the irradiations in various operating power reactors and in experimental reactors. A complete record of the chemical analysis, fabrication history and mechanical properties of all surveillance test materials is maintained.

The results of detailed chemical analyses on the plates which comprise the beltline region of the vessel and on a sample weld with identical materials as the girth weld passing through the maximum flux region are presented in Table 5.2-4.

The exposure locations and a summary of the specimens at each location is presented in Table 5.4-2. The pre-irradiation NDT temperature of each plate in the intermediate and lower vessel shell courses is determined from the drop weight tests and correlated with Charpy impact tests.

Base metal test specimens are fabricated from sections of the lower shell plate material since it exhibits the highest unirradiated NDT temperature. All base material test specimens are cut from the same shell plate. This material is heat treated to a condition which is representative of the final heat treated condition of the base metal in the completed reactor vessel.

Weld metal and HAZ material are produced by welding together two plate sections from the lower shell course of the reactor vessel. All HAZ test materials are also fabricated from the plate which exhibits the highest unirradiated NDT temperature.

The material used for weld metal and HAZ test specimens is adjacent to the test material used for ASME Code, Section III tests and is at least one plate thickness from any water-quenched edge. The procedures used for making the shell girth welds in the reactor vessel welds are followed for inspection of the welds in the test materials. The welded plates are heat treated to a condition representative of the final heat treated condition of the completed reactor vessel.

The test specimens are contained in six irradiation capsule assemblies. The axial position of the capsules is bisected by the midplane of the core. The circumferential locations include the peak flux regions.

The location of the in-vessel surveillance capsule assemblies is shown in Figure 5.4-2. A typical surveillance capsule assembly is shown in Figure 5.4-3. A typical Charpy impact compartment assembly is shown in Figure 5.4-4. A typical tensile monitor compartment assembly is shown in Figure 5.4-5.

Fission threshold detectors (U-238) are inserted into each surveillance capsule to measure the fast neutron flux. Threshold detectors of Ni, Ti, Fe, S, and Cu with known Cobalt content have been selected for this application to monitor the fast neutron exposure. Cobalt is included to monitor the thermal neutron exposure.

The selection of threshold detectors is based on the recommendations of ASTM E-261, "Method for Measuring Neutron Flux by Radioactive Techniques". Activation of the specimen material will also be analyzed to determine the amount of exposure.

The maximum temperature of the encapsulated specimens will be monitored by including in the surveillance capsules small pieces of low-melting point eutectic alloys individually sealed in quartz tubes.

The temperature monitors provide an indication of the highest temperatures to which the surveillance specimens are exposed but not the temperature history or the variance between the temperature history of different specimens. These factors, however, affect the accuracy of the estimated vessel material NDTT to only a small extent.

Tests specimens removed from the surveillance capsules will be tested in accordance with ASTM Standard Test Methods for Tension and Impact Testing. The data obtained from testing the irradiated specimens will be compared with the unirradiated data and an assessment of the neutron embrittlement of the reactor vessel material will then be made. This assessment of the NDTT shift is based on the temperature shift in the average Charpy curves, the average curves being considered representative of the material. This shift, when measured at the 30 ft.-lb. Level between initial and irradiated Charpy curves, is referred to as “the shift” or delta $RT_{NDT.}$

The periodic analysis of the surveillance samples permit the monitoring of the neutron radiation effects upon the vessel materials. The Charpy curve $RT_{NDT}$ shift results from the irradiated surveillance samples are compared to predicted $RT_{NDT}$ shifts for each material at the same fluence to determine if the values are consistent with pertinent radiation effects data studies accumulated under similar conditions.

If, with due consideration for uncertainties in $RT_{NDT}$ determination, the surveillance samples exhibit a higher than anticipated $RT_{NDT}$ shift, then appropriate limitations would be imposed on permissible operating pressure-temperature combinations and transients to insure that existing reactor vessel stresses are low enough to preclude brittle fracture failure.

All surveillance capsules are inserted into their designated holders during the final reactor assembly operation. Each capsule remains in the reactor for the tentative time period listed in Table 5.4-3, which shows the target fluence for each of the capsules.

The fluence values in Table 5.4-3 are accurate within +30 percent and -30 percent. The total uncertainty is composed of eight independent uncertainties. Among them, variations of core power distribution, reactor vessel downcomer region dimension, and homogenization of core data are three major uncertainties. Through utilization of capsule lead factor, the fluence level at the vessel wall can be determined from the fluence level at the capsule. The capsule removal schedule has been revised in accordance with ASTM E185-82.

5.4.4.1 Results of Evaluation of Irradiated Capsule W-97º, 104º and 284°

The first surveillance wall capsule (W-97) was removed from the St. Lucie Unit 1 reactor vessel in May 1983 after 4.67 effective full power years of reactor operation (Reference 3). Analysis of capsule neutron threshold detectors provided a capsule fluence measurement, which is listed in Table 5.4-3. The radiation induced transition temperature shifts (delta $RT_{NDT}$) for the base metal were 70ºF and 68ºF for the transverse and longitudinal orientation specimens respectively. The radiation induced transition temperature shift for the weld metal was 74ºF. The irradiated upper shelf energy values for the vessel weld metal and base materials samples ranged from 78 ft.-lb. to 107 ft.-lb. which is well in excess of the 50 ft.-lb. value currently considered to be a reasonable lower limit for continued sale operation. The capsule plate and weld material specimens exhibited shifts in $RT_{NDT}$ and reductions of upper shelf energy values that were within the predictions for the material when consideration for uncertainties of the test method were included.

The second surveillance capsule (104º) was removed from the St. Lucie Unit 1 reactor vessel after 9.515 effective full power years of reactor operation (Reference 12). Analysis of capsule neutron threshold detectors provided a capsule fluence measurement, which is listed in Table 5.4-3. The radiation induced transition temperature shift for the base metal was 67ºF for the longitudinal orientation specimens. The radiation induced transition temperature shift for the weld metal was 73ºF. The irradiated upper shelf energy values for the vessel weld metal and longitudinal base materials samples ranged from 108 ft.-lb. to 116 ft.-lb. which is well in excess of the 50 ft.-lb. value currently considered to be a reasonable lower limit for continued safe operation. Standard reference material (SRM) plate samples were included in this capsule as a part of the HSST test program. Theses SRM samples exhibited a $RT_{NDT}$ shift of 110ºF and an upper shelf energy value of 87 ft.-lb. The capsule reactor vessel material specimens exhibited shifts in $RT_{NDT}$ and reductions of upper shelf energy values that were within the predictions for the material when consideration for uncertainties of the test method were included. The shift in $RT_{NDT}$ for the SRM material was also within the predictions for this material.

The third surveillance capsule (284°) was removed from the St. Lucie Unit 1 reactor vessel after 17.23 effective full power years of reactor operation (Reference 13). Analysis of capsule neutron threshold detectors provided a calculated capsule fluence measurement, which is listed in Table 5.4-3. The radiation induced transition temperature shift for the base metal was 85°F and 88°F for the transverse and longitudinal orientation specimens respectively. The radiation induced transition temperature shift for the weld metal was 68°F. The irradiated upper shelf energy values for the vessel weld metal and base material samples ranged from 88 ft-lb to 110 ft-lb which is well in excess of the 50 ft-lb value currently considered to be a reasonable lower limit for continued safe operation. The capsule reactor vessel material specimens exhibited shifts in $RT_{NDT}$ and reductions of upper shelf energy values that were within the predictions for the material when consideration for uncertainties of the test method were included.

5.4.4.2 Post Thermal Shield Removal Surveillance

Following the 1983 removal of the thermal shield, one in-vessel dosimetry capsule, one ex-vessel dosimetry capsule and twelve ex-vessel wire dosimeters were installed. The in vessel capsule was installed in the W-97° position. The ex-vessel capsule was placed at the same azimuthal and axial position as the W-97° capsule but in the annular space between the vessel and primary shield wall. The ex-vessel wire dosimeters were placed in the annular space in positions to give a detailed azimuthal flux profile in a 45° octant as well as to evaluate neutron flux symmetry around the vessel.

The in-vessel replacement dosimetry capsule has the same external configuration as the existing St. Lucie Unit 1 surveillance capsules with minor design modifications to facilitate remote installation. The capsule compartments contain three sets of nine neutron dosimeters and one set of four temperature monitors (See Figure 5.4-3b). No mechanical test specimens are included. The replacement dosimetry capsule data will complement the irradiated W-97 surveillance capsule evaluation since neutron flux measurements at the same azimuthal position will be available both before and after removal of the thermal shield.

The ex-vessel capsule contains flux monitor sets identical to the replacement in-vessel capsule.

There are six ex-vessel iron wire dosimeters and six nickel wire dosimeters located per Table 5.4-6.

These capsules are stamped at each end for identification with the designations of FE 1, 2, 3, 4, 5, and 6, and NI 1, 2, 3, 4, 5 and 6.

5.4.5 NONDESTRUCTIVE TESTS

During fabrication of the reactor vessel, nondestructive tests based upon Section III of the ASME Boiler and Pressure Vessel Code were performed on all welds, forgings and plates as follows:

All full penetration pressure containing welds were 100 percent radiographed to the standards of paragraphs N-624 of Section III of the ASME Boiler and Pressure Vessel Code. Other pressure containing welds such as used for the attachment of mechanism housings, vents and instrument housings to the reactor vessel head were inspected by liquid penetrant tests of the root passes, each ½ inch of weld material or one-third of weld thickness (whichever was less) and the final surface.

All forgings were inspected by ultrasonic testing, using longitudinal beam techniques. In addition, ring forgings were tested using shear wave techniques. Rejection under longitudinal beam inspection, with calibration so that the first back reflection is at least 75 percent of screen height, was based on interpretation of indications causing complete loss of back reflection. Rejection under shear wave inspection was based on indications, exceeding in amplitude the indications from a calibration notch whose depth in 3 percent of the forging thickness, not exceeding 3/8-inch with a length of 1 inch. All forgings were also subjected to magnetic-particle examination or liquid penetrant testing depending upon the material. Rejection was based on Section III of the ASME Code, paragraph N626.3 for magnetic-particle and paragraph N627.3 for dye-penetrant testing.

Plates were ultrasonically tested using longitudinal ultrasonic testing techniques. Rejection, under longitudinal beam testing performed in accordance with ASME Code, and with calibration so that the first back reflection is at least 50 percent of screen height, was based on defects causing complete loss of back reflection. Any defect which showed a total loss of back reflection which could not be contained within a circle whose diameter is the greater of 3 inches or one-half the plate thickness was unacceptable. Two or more defects smaller than described above which caused a complete loss of back reflection were unacceptable unless separated by a minimum distance equal to the greatest diameter of the larger defect unless the defects were contained within the area described above.

Nondestructive testing of the vessel was performed during several stages of fabrication with quality control in critical areas such as frequent calibration of test instruments, metallurgical inspection of all weld rod and wire, and adherence to the nondestructive testing requirements of Section III of the ASME Boiler and Pressure Vessel Code.

The detection of flaws in irregular geometries was facilitated because most nondestructive testing of the materials was completed while the material was in its simplest form. Nondestructive inspection during fabrication was scheduled so that full penetration welds were capable of being radiographed to the extent required by Section III of the ASME Boiler and Pressure Vessel code.

Each of the vessel studs received one ultrasonic test and one magnetic particle inspection during the manufacturing process.

The ultrasonic test was a radial longitudinal beam inspection. Rejection was based on any discontinuity which caused an indication which exceeded 20 percent of the height of the adjusted first back reflection. Any discontinuity which prevents the production of a first back reflection of 50 percent of the screen height was also cause for rejection.

The magnetic particle inspection was performed on the finished studs. Linear axially aligned defects whose lengths are greater than 1 inch long and linear nonaxial defects were unacceptable.

The vessel studs are stressed as they are elongated by the stud tensioners during the initial installation of the vessel head and at each refueling. The amount of elongation versus hydraulic pressure on the tensioner is compared with previous readings to detect any significant changes in the elongation properties of the studs.

During fabrication of the other components of the reactor coolant system, such as the steam generator, pressurizer and piping, nondestructive testing based upon the requirements of Section III of the ASME Boiler and Pressure Vessel Code is used to determine the acceptance criteria for various size flaws. The requirements for the Class A vessel are the same as the reactor vessel. Vessels designated as Class C were fabricated to the standards of Subsection C, Article 21 of Section III of the ASME Code.

During the manufacture of the reactor vessel, in addition to the areas covered by the ASME Boiler and Pressure Vessel Code, Section III, quality control included:

a) preparation of detailed purchase specifications which included cooling rates for test samples

b) requiring vacuum degassing for all ferritic plates and forgings

c) specification of fabrication instructions for plates and forgings to provide control of material prior to receipt and during fabrication

d) use of written instructions and manufacturing procedures which enabled continual review based on past and current manufacturing experiences

e) performance of chemical analysis of welding electrodes, welding wire, and materials for automatic welding, thereby providing continuous control over welding materials

f) the determination of NDT temperature through use of drop weight testing methods as well as Charpy impact tests

g) test programs on fabrication of plates up to 15 inches thick to provide information about material properties as thickness increases

h) documentation of tests and inspections and formal retention of records for future surveillance comparisons

i) and longitudinal wave ultrasonic testing was performed on 100 percent of all plate material.

Cladding for the reactor vessel is a continuous integral surface of corrosion resistant material, 5/16 inch nominal thickness. The procedure used specified the type of weld rod, welding position, speed of welding, nondestructive testing requirements, and was in compliance with the ASME Boiler and Pressure Vessel Code. The cladding is ultrasonically inspected for lack of bond at intervals not to exceed 12 inches transverse to the direction of welding. Unbonded areas equal to, or in excess of calibration require additional scanning of the surrounding material until the boundary of the discontinuity is established. An area of unbonded clad in excess of acceptance standards is repaired.

Upon completion of all postweld heat treatments, the reactor vessel was hydrostatically tested, after which all weld surfaces, including those of welds used to repair material, were magnetic particle inspected in accordance with Section III, paragraph N-618 of the ASME Boiler and Pressure Vessel Code.

Table 5.4-4 summarizes the component inspection program during fabrication and construction.

Periodic tests and inspections of the reactor coolant system are conducted after startup on a regular basis.

For preoperational and inservice inspection of the reactor coolant system, refer to Section 16.4. Tests for reactor coolant system integrity after a shutdown following refueling, modification or repair are specified in Chapter 16.

Replacement RVCH Non-Destructive Inspection

Table 5.4-4 summarizes the quality assurance program inspections for the replacement RVCH. In this table are identified all of the non-destructive test and inspections required by the RVCH Certified Design Specification. All tests required by the applicable Code (ASME Section III, Applicable Edition and Addenda) are included in the table as well as any additional test or more stringent acceptance criteria as may have been specified in the Certified Design Specification for the RVCH.

In addition to the inspections summarized in Table 5.4-4, there are those inspections which the equipment supplier performs to confirm the adequacy of material he receives, and those performed by the manufacturer of the materials in producing the basic materials. Procedures for performing all of the examinations are consistent with those established in the ASME Code Section III and are reviewed by qualified FPL and Owner's Agent representatives. These procedures have been developed to provide the highest assurance of quality in the materials and fabrication. They consider not only the size of flaws, but equally as important, how the material is fabricated, the orientation and type of possible flaws, and the areas of most severe service conditions. The volumetric inspections (Ultrasonic Testing) of the forging were done using both the straight beam and the angle beam techniques. In addition the surfaces most subject to damage as a result of forging, heat treating, forming, fabricating, and hydrostatic testing received 100% surface inspections by Magnetic Particle or Liquid Penetrant Testing at various stages during the processes and after final completion of the hydrostatic test of the RVCH.

The RVCH requires welding and weld cladding performed under procedures which require the use of both preheat and post-weld heat treating. Pre-heat of weld areas and post-weld heat treating are performed on all welds on the replacement RVCH. Pre-heat and post-weld heat treat of weldments both serve the common purpose of producing tough, ductile metallurgical structures in the weldment. Pre-heating produces tough ductile welds by minimizing the formation of hard non-ductile zones whereas post-weld heat treating achieves this by tempering any hard zones which may have formed due to rapid cooling.

FPL and the Owner's Agent reviewed the manufacturer's quality control methods and results of the vendor and subvendors of the RVCH and have found them to be acceptable. FPL and the Owner's Agent Quality Control engineers monitored the supplier's work, witnessing key inspections not only in the supplier's shop but also in the shops of the subvendor of the major forging. Normal surveillance includes verification of records of material, physical and chemical properties, review of radiographs, performance of the required tests and qualification of supplier personnel. FPL and the Owner's Agent reviewed the manufacturing quality control results and records of the vendor and subvendors of the RVCH and found them to be complete and acceptable.

## 5.4.6 ADDITIONAL TESTS

During design and fabrication of the reactor vessel additional tests were performed as summarized in Table 5.4.5.

REFERENCES FOR SECTION 5.4


1. R. E. Uhrig (FPL) to T. M. Novak (NRC) Re: St. Lucie Unit 1, Docket No. 50-335, Natural Circulation Cooldown, L-80-343, dated 10/17/80.

2. R. E. Uhrig (FPL) to R. A. Clark (NRC) Re: St. Lucie Unit 1, Docket No. 50-335, Natural Circulation Cooldown, L-80-431, dated 12/30/80.

3. J. W. Williams, Jr. (FPL) to D. G. Eisenhut (NRC) Re: St. Lucie Unit 1, Docket No. 50-335, Reactor Vessel Surveillance Specimen Capsule W-97, L-83-583, dated 12/14/83.

4. D. A. Sager (FPL) to NRC Re: St. Lucie Units 1 and 2, Docket No. 50-335 and 50-389, Generic Letter 92-01 Revision 1 Response to Request For Additional information, L-94-169, dated 7/1/94.

5. Combustion Engineering Report F-NLM-007, Program for Irradiation Surveillance of Hutchinson Island Plant (St. Lucie Unit 1) Reactor Vessel Materials, dated 9/15/70.

6. Combustion Engineering Report, TR-F-MCM-005 Evaluation of Baseline Specimens, St. Lucie Unit 1.

7. Deleted

8. Deleted

9. St. Lucie Unit 1, Technical Specification License Amendment No. 100.

10. J. H. Goldberg (FPL) to NRC Document Control Desk-Proposed License Amendment Reactor Vessel Material Irradiation Surveillance Schedule, L-89-357, dated October 2, 1989.

11. D.A. Sager (FPL) to NRC, Attn: Document control Desk - St. Lucie Units 1 and 2, Docket No. 50-335 and 50-389, Generic Letter 92-01, Revision 1, Response to Request for Additional Information (RAI), L-93-286, dated November 15, 1993.

12. "Analysis of the Capsule at 104º from the Florida Power and Light Company St. Lucie Unit No. 1 Reactor Vessel Radiation Surveillance Program," Westinghouse Electric Corp., WCAP-12751, November, 1990.

13. "Analysis of Capsule 284° from the Florida Power and Light Company St. Lucie Unit 1 Reactor Vessel Radiation Surveillance Program," Westinghouse Electric Co. LLC., WCAP-15446, Revision 1, January 2002.

14. J.A. Stall (FPL) to NRC, "St. Lucie Units 1 and 2, Docket No. 50-335 and 50-389, Reactor Vessel Structural Integrity, Generic Letter 92-01, Revision 1, Updated Information", L-97-223, dated August 28, 1997.

15. Westinghouse Report, CE-NPSD-683-A Task-1174, Revision 06, "Development of a RCS Pressure & Temperature Limit Report for the Removal of P-T Limits and LTOP Requirements from the Technical Specifications", April 2001.

TABLE 5.4-1

REACTOR VESSEL PARAMETERS

| | |
|---|---|
| Design Pressure, psig | 2485 |
| Design Temperature, F | 650 |
| Nozzles | |
| Inlet (4 ea.), ID, in. | 30 |
| Outlet (2 ea.), ID, in. | 42 |
| CEDM (65), ID, in. | 2,728 |
| Instrumentation (8), nominal in. | 4,625 |
| Vent (1), nominal, in. | 3/4 |
| Dimensions | |
| Inside Diameter, nominal, in. | 172 |
| Overall Height, Including CEDM Nozzles | 503 3/4 |
| Height, Vessel without Head | 408 9/16 |
| Wall Thickness, minimum, in. | 8 5/8 |
| Upper Head Thickness, minimum, in. | 7 3/8 |
| Lower Head Thickness, minimum, in. | 4 3/8 |
| Cladding Thickness, Bottom Head, minimum in. | 3/16 |
| Cladding Thickness, Remainder of vessel, minimum, in. | 1/8 |
| Cladding Thickness, nominal, in. | 5/16 |
| Material (Note 1) | |
| Shell | SA-533-65 Grade B, Class 1 Steel |
| No. of Shell Courses | 2 |
| Forgings | SA-508-64, Class 2 |
| Claddings | Type 308 Stainless Steel* |
| Dry Weights | |
| Head, lb. | 158,400 |
| Vessel, without flow skirt, lb. | 682,000 |
| Studs, Nuts, and Washers, lb. | 38,900 |
| Flow skirt, lb. | 5,030 |
| Total | 884,330 |

* Weld deposited austenitic stainless steel Type 308, which is equivalent to SA-240, Type 304 in contact with coolant.

Note 1: Material for Replacement RVCH

TABLE 5.4-1 (cont.)

Replacement RVCH

| | |
|---|---|
| Forging | SA-508, Class 3 |
| Lifting Lugs | SA-533 Gr B,<br>Class 1 |
| CEDM Nozzles | SB-167 690 (UNS N06690)<br>Code Case N4792 |
| CEDM Adapters | SB-166 690 (UNS N06690)<br>Code Case N4792 |
| Instrumentation Nozzles | SB-167 690 (UNS N06690)<br>Code Case N4792 |
| Instrumentation Nozzle Adapter | ASME SA-479 Type 304 |
| Austentic Stainless Steel Cladding | ER-309L/ER-308L |

Welds

| Base Material | Weld Material |
|---|---|
| SA-508 to SB-167 | ERNiCrFe-7 or ENiCrFe-7 |
| SB-167 to SB-166 | ERNiCrFe-7 or ENiCrFe-7 |
| SB-167 to SA-479 | ERNiCrFe-7 |
| SA-508, Class 3 to SA-533 Gr B, Class 1 | SFA 5-5 or E8018 |

TABLE 5.4-2

SURVEILLANCE SPECIMENS PROVIDED FOR EACH EXPOSURE LOCATION

| Capsule Location on Vessel Wall (See Figure 5.4-2) | Base Metal Imact L[a] | Base Metal Imact T[b] | Tensile | Weld Metal Impact | Tensile | HAZ Impact | Tensile | Reference Impact[c] | Total Specimens Impact | Total Specimens Tensile |
|---|---|---|---|---|---|---|---|---|---|---|
| 83° | 12 | 12 | 3 | 12 | 3 | 12 | 3 | -- | 48 | 9 |
| 97° | 12 | 12 | 3 | 12 | 3 | 12 | 3 | -- | 48 | 9 |
| 104° | 12 | - | 3 | 12 | 3 | 12 | 3 | 12 | 48 | 9 |
| 263° | 12 | - | 3 | 12 | 3 | 12 | 3 | 12 | 48 | 9 |
| 277° | 12 | 12 | 3 | 12 | 3 | 12 | 3 | -- | 48 | 9 |
| 284° | 12 | 12 | 3 | 12 | 3 | 12 | 3 | | 48 | 9 |
| | 72 | 48 | 18 | 72 | 18 | 72 | 18 | 24 | 288 | 54 |

(a) L = Longitudinal
(b) T = Transverse
(c) Reference Material Correlation Monitors

TABLE 5.4-3

CAPSULE REMOVAL SCHEDULE (5)

| Location on Vessel Wall | Approximate Removal Schedule EFPY | Predicted Fluence $n/cm^2$ | Lead Factor (3) |
|---|---|---|---|
| 97° (1) | 4.67 | $5.174 \times 10^{18}$ | ----- |
| 104° (1) | 9.515 | $7.885 \times 10^{18}$ | ------ |
| 284° (1) | 17.23 | $1.243 \times 10^{19}$ | ------ |
| 263° | 38 | $3.79 \times 10^{19}$ | 1.34 |
| 83° (2)(4) | 45 | $4.60 \times 10^{19}$ | 1.34 |
| 277° (4) | Standby | ------ | 1.34 |

(1) Numbers for these capsules are actual. Fluence values reflect the most recent analysis (reference 13).

(2) The fifth capsule is not required to be tested per ASTM E185. It is reserved as a standby should an additional license period be considered.

(3) Lead Factor is defined as the capsule fluence divided by RV base metal peak fluence.

(4) The capsule removal times were switched for the 83° and 277° capsules. The capsule at 277° was found to be missing its ACME threaded top during a 1996 vessel inspection (Condition Report 96-1064). Without the top, a special removal tool will be required to retrieve the 277° capsule. Both capsules contain identical samples and receive similar fluence since they are 180° apart.

(5) Capsule removal schedule changes require NRC approval per 10 CFR 50, Appendix H.

## TABLE 5.4-4

## REACTOR COOLANT SYSTEM NON-DESTRUCTIVE TESTS

1. Reactor Vessel (See Heading 6 for Replacement (RVCH)

| | |
|---|---|
| Forgings | |
| Flanges | UT, MT |
| Studs | UT, MT |
| Cladding | UT, PT |
| Nozzles | UT, MT |
| Plates | UT, MT |
| Cladding | UT, PT |
| Welds | |
| Main Seams | RT, MT |
| Main Nozzles to Shell | RT, MT |
| Cladding | UT, PT |
| Nozzle Safe Ends | RT, MT |
| Vessel Support Buildup | UT, MT |
| All Welds - After Hydrostatic Test | MT or PT |

2. Replacement Steam Generators

| | |
|---|---|
| Tube Sheet | |
| Forging | UT, MT |
| Cladding | UT, PT |
| Primary Head | |
| Forging | UT, MT |
| Cladding | UT, PT |
| Secondary Shell and Head | |
| Plates and Forgings | UT, MT |
| Tubes | UT, ET |
| Nozzles (Forgings) | UT, MT (or PT) |
| Studs | UT, MT |
| Welds | |
| Secondary Shell, Longitudinal | RT, MT, UT |
| Shell, Circumferential | RT, MT, UT |
| Cladding | UT, PT |
| Nozzles to Shell | RT, MT, UT |
| Tube-to-Tube Sheet | PT |
| Instrument Connections | PT |
| Temporary Attachments after Removal | MT |
| All Welds - After Hydrostatic Test | MT or PT |
| Nozzle Safe Ends | RT, (MT or PT), UT |
| Level Nozzles | PT |

TABLE 5.4-4 (Cont.)

| | | |
|---|---|---|
| 3. | <u>Pressurizer</u> | |
| | Heads | |
| | Forgings | UT, MT |
| | Cladding | UT, PT |
| | Shell | |
| | Forgings | UT, MT |
| | Cladding | UT, PT |
| | Heaters | |
| | Tubing | UT, PT |
| | Safe Ends | UT, MT |
| | Studs | UT, MT |
| | Welds | |
| | Shell, Circumferential | RT, MT |
| | Cladding | UT, PT |
| | Nozzle Safe Ends | RT, PT |
| | Instrument Connections | PT |
| | Support Skirt | RT, MT |
| | Temporary Attachments after Removal | MT or PT |
| | All Welds after Hydrostatic Test | MT or PT |
| | Heater Assembly | PT |
| | End Plug Weld | PT |
| 4. | <u>Pumps</u> | |
| | Castings | RT, PT |
| | Forgings | UT, PT |
| | Welds | |
| | Circumferential | RT, PT |
| | Instrument Connections | PT |
| | All Welds after Hydrostatic Test | PT |
| 5. | <u>Piping</u> | |
| | Fittings (castings) | RT, PT |
| | Pipe (cast) | RT, PT |
| | Nozzles (carbon steel forgings) | UT, MT |
| | Pipe and elbows | |
| | Carbon steel plate | UT, MT |
| | Roll bond clad | UT, PT |

TABLE 5.4-4 (Cont.)

| | |
|---|---|
| Welds | |
| Circumferential | RT, MT |
| Nozzle to Run Pipe | RT, MT, UT |
| Instrument Connections | PT |
| Cladding | UT, PT |
| Safe ends to Nozzles | RT, PT |

| | | | RT | UT | PT | MT | ET |
|---|---|---|---|---|---|---|---|
| 6. | Replacement Reactor Vessel Closure Head | | | | | | |
| 6.1 | Head Mono-block Forging | | | | | | |
| | 6.1.1 | After Rough Machining | | yes | | yes | |
| | 6.1.2 | After Final Machining | | yes | | | |
| | 6.1.3 | Machined Surfaces To Be Clad | | | yes[4] | | |
| | 6.1.4 | External Un-clad Surfaces | | | | yes[1] | |
| | 6.1.5 | All Clad Surfaces | | yes[2&3] | yes[5] | | |
| | 6.1.6 | Final Machined O-Ring Groove | | | yes[6] | | |
| 6.2 | SB-167 UNS N0 6690 CEDM & ICI | | | yes[10] | yes[7] | | |
| 6.3 | SB-166 UNS N0 6690 CEDM Nozzles | | | yes[10] | yes[7] | | |
| 6.4 | SA-479 Type 304 ICI Nozzle Adapter | | | yes[10] | yes[7] | | |
| 6.5 | Weldment | | | | | | |
| | 6.5.1 | All Weld Prep Areas | | | yes[8] | | |
| | 6.5.2 | Root Pass of All Welds | | | yes | | |
| | 6.5.3 | Final Surface of All Welds | | | yes[9] | | |
| | 6.5.4 | Nozzle to Forging Weld Area | | yes[11] | | | |
| | 6.5.5 | CEDM & ICI Nozzle to Adapter Butt Weld | yes | | | | |
| | 6.5.6 | Vent Pipe Nozzle to Vent Pipe Butt Weld | yes | | | | |

1. All Accessible ferritic surfaces after final hydrostatic test.
2. Sealing and bearing surfaces of the head examined for defects and bond.
3. Non-sealing and non-bearing surfaces examined for bond.
4. After machining and prior to cladding.
5. After post weld heat treatment.
6. The bottom sealing surfaces must be free of Indications (PT White).
7. After final machining.
8. After final weld prep machining but prior to root pass welding.
9. Final surface of all CEDM nozzle attachment and vent pipe welds must be free of indications (PT White).
10. After rough machining.
11. This is a baseline for future examinations.

---

Legend:

RT = Radiographic
UT = Ultrasonic
PT = Dye Penetrant
MT = Magnetic Particle
ET = Eddy Current

TABLE 5.4-5

REACTOR COOLANT SYSTEM ADDITIONAL INSPECTIONS

| Reactor Vessel | Inspection | Code Requirement |
| --- | --- | --- |
| Ultrasonic Testing | Of weld clad for bond | None |
| Dye Penetrant | Test root, each 1/2 inch and final layer of welds for partial penetration welds to control element drive mechanism head adapters and instrument tube connections | PT test of each ½ weld throat or ½” whichever is less |
| Steam Generator | | |
| Ultrasonic Test | Defects in tube sheet clad | None |
| | Weld clad for bond | None |
| Pressurizer | | |
| Ultrasonic Testing | Clad for bond | None |

TABLE 5.4-6

EX-VESSEL DOSIMETER CAPSULE LOCATIONS

| FLUX MONITOR CAPSULE | FLUX NICKEL WIRE CAPSULE | FLUX IRON WIRE CAPSULE | AZIMUTH (DEGREES) |
|---|---|---|---|
| - | 1 | - | 23° |
| - | 2 | 1 | 90° |
| - | 3 | 2 | 96° |
| 1 | - | - | 97° |
| - | 4 | 3 | 105° |
| - | - | 4 | 108° |
| - | - | 5 | 135° |
| - | 5 | - | 207° |
| - | - | 6 | 284° |
| - | 6 | - | 286° |

TABLE 5.4-7

REACTOR VESSEL BELTLINE PLATES

| LOCATION | HEAT NO. | CODE NO. | %Cu | %Ni | RT(NDT) |
|---|---|---|---|---|---|
| Intermediate Shell | A-4567-1 | C-7-1 | 0.11 | 0.64 | 0°F |
| Intermediate Shell | B-9427-1 | C-7-2 | 0.11 | 0.64 | -10°F |
| Intermediate Shell | A-4567-2 | C-7-3 | 0.11 | 0.58 | 10°F |
| Lower Shell | C-5935-1 | C-8-1 | 0.15 | 0.56 | 20°F |
| Lower Shell | C-5935-2 | C-8-2 | 0.15 | 0.57 | 20°F |
| Lower Shell | C-5935-3 | C-8-3 | 0.12 | 0.58 | 0°F |

TABLE 5.4-8

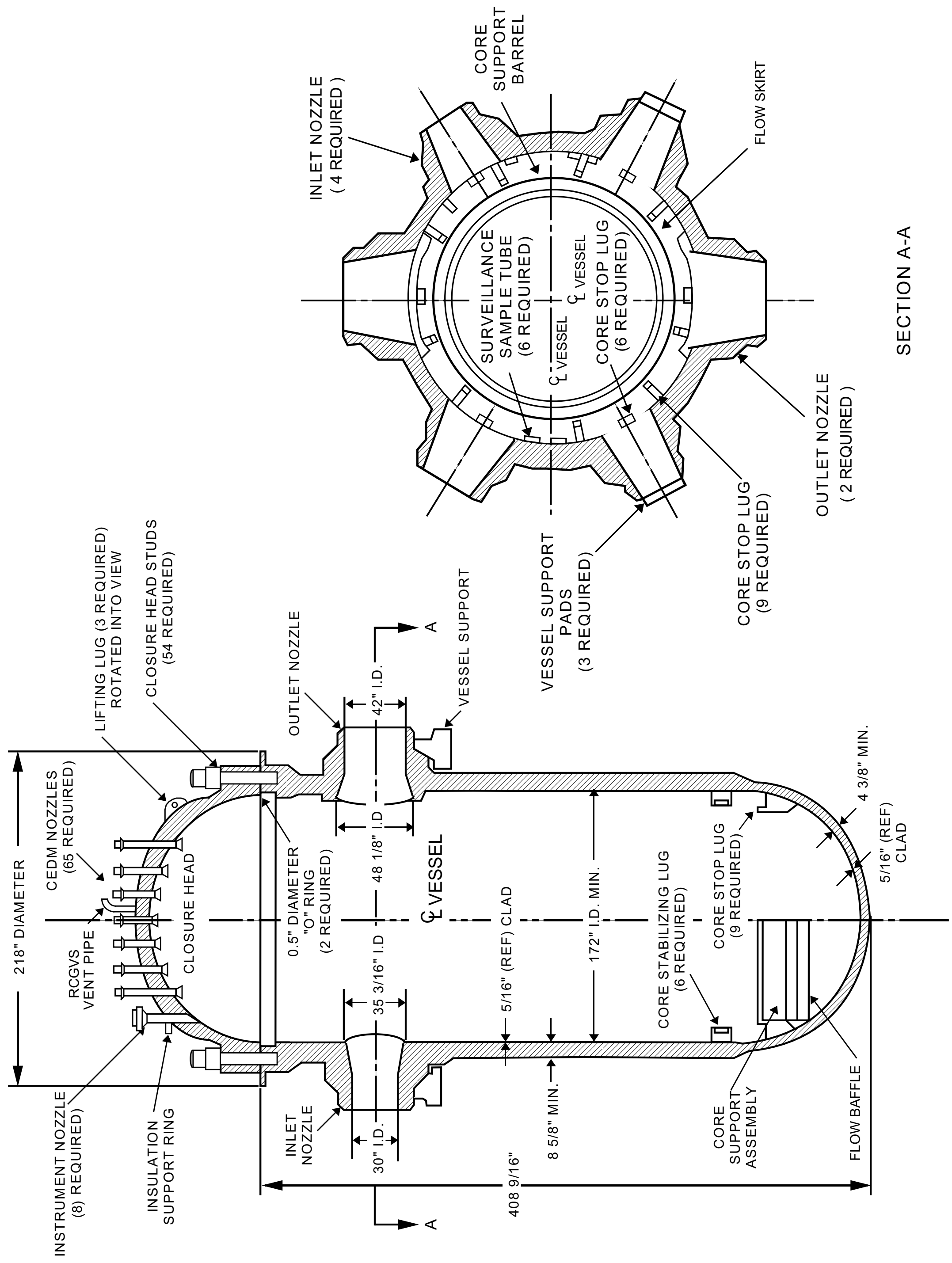
REACTOR VESSEL BELTLINE WELDS

| WELD LOCATION | WIRE SEAM NO. | HEAT NO. | FLUX TYPE | BATCH | %Cu(4)(a) | %Ni(4)(a) | RTNDT(4) |
|---|---|---|---|---|---|---|---|
| Intermediate Shell Longitudinal Seam | 2-203A | A-8746/34BOO9<br>M/A IAGI* | Linde 124<br>3688 | 3878 & | 0.19 | 0.09 | -56 |
| Intermediate Shell Longitudinal Seam | 2-203B | A-8746/34BOO9<br>M/A IAGI*<br>M/A CBB* | Linde 124<br>3688 | 3878 & | 0.19 | 0.09 | -56 |
| Intermediate Shell Longitudinal Seam | 2-203C | A-8746/34BOO9 | Linde 124 | 3878 &<br>3688 | 0.19 | 0.09 | -56 |
| Lower Shell Longi-tudinal Seam | 3-203A | 305424<br>M/A KBEJ* | Linde 1092 | 3889 | 0.27 | 0.63 | -60(11) |
| Lower Shell Longi-tudinal Seam | 3-203B | 305424<br>M/A KBEJ* | Linde 1092 | 3889 | 0.27 | 0.63 | -60(11) |
| Lower Shell Longi-tudinal Seam | 3-203C | 305424 | Linde 1092 | 3889 | 0.27 | 0.63 | -60(11) |
| Intermediate to Lower Girth Seam | 9-203 | 90136<br>M/A ABEA*<br>M/A FOAA* | Linde 0091 | 3999 | 0.27 | 0.07 | -60(6) |

*Manual shielded metal arc electrode (all others automatic submerged arc wire).

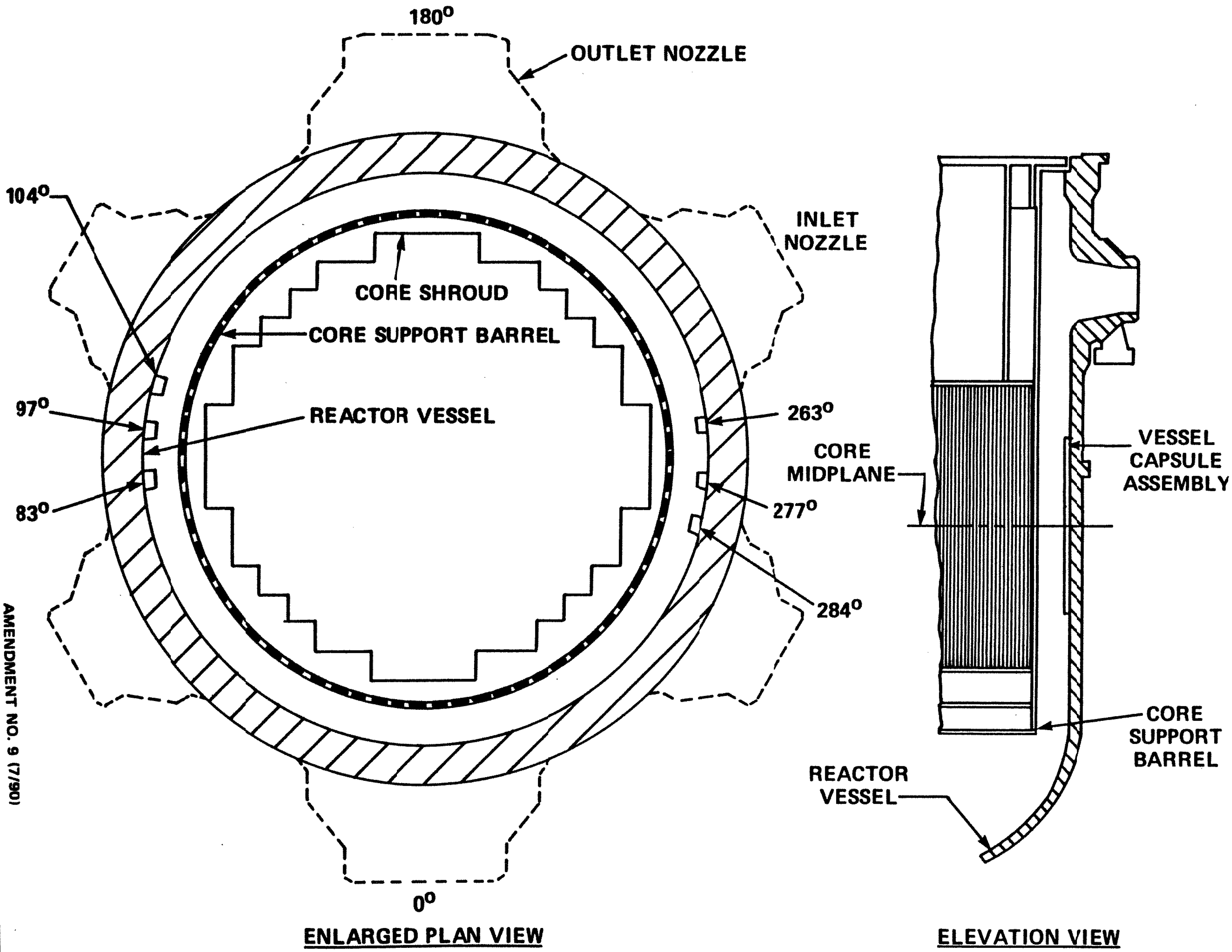
(a) The weld metal copper and nickel chemical values are based on the “best estimate” copper and nickel values for a specific weld wire heat using all industry available data. The “best estimate” values were determined in response to NRC GL 92-01, Rev. 1, Supplement 1 and were submitted to the NRC in FPL Letter L-97-223 (Reference 14).

Note: Numbers identified in parentheses refer to Section 5.4 references.




Florida Power & Light Company
St. Lucie Plant Unit 1

Reactor Vessel
Figure 5.4-1

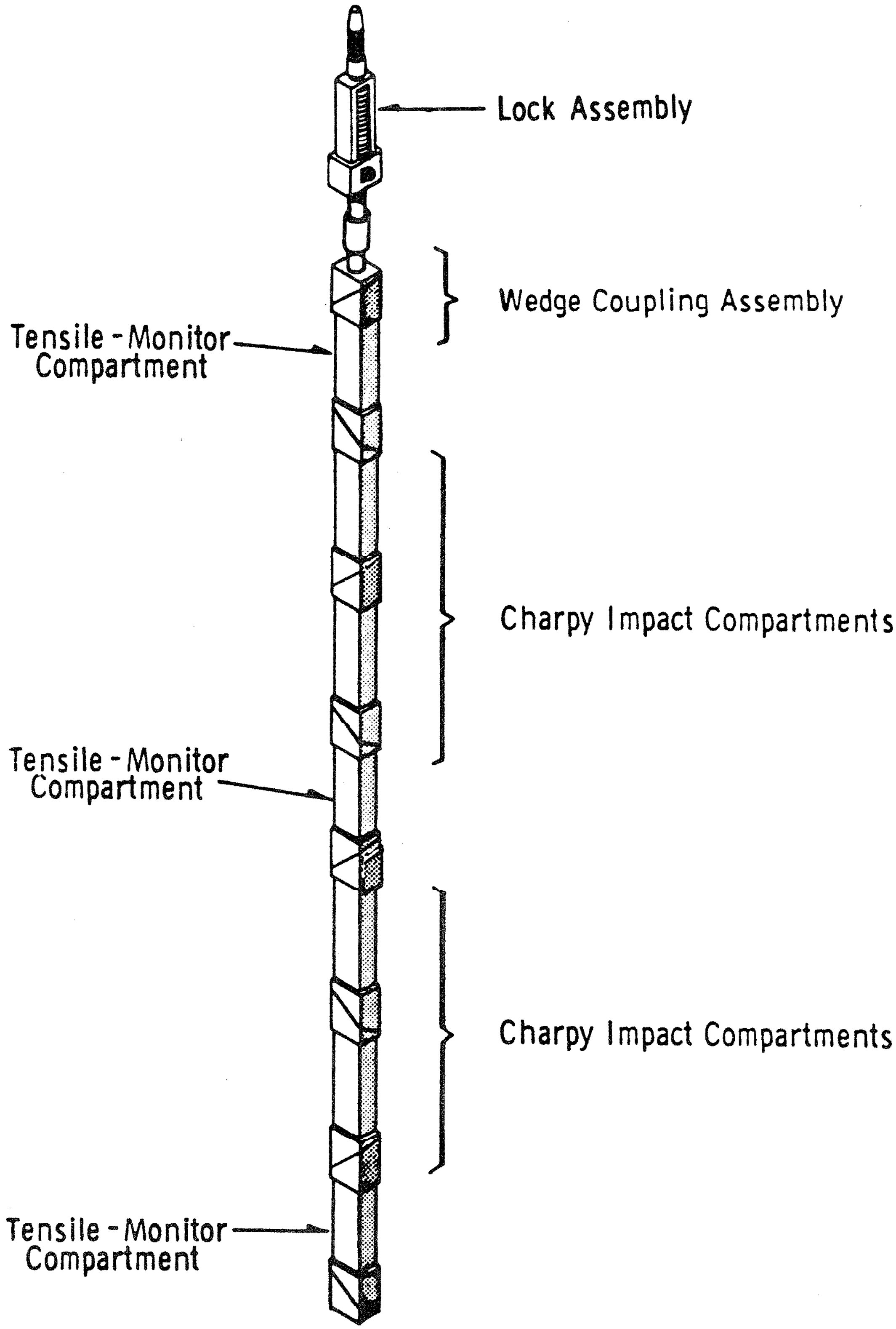



AMENDMENT NO. 9 (7/90)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

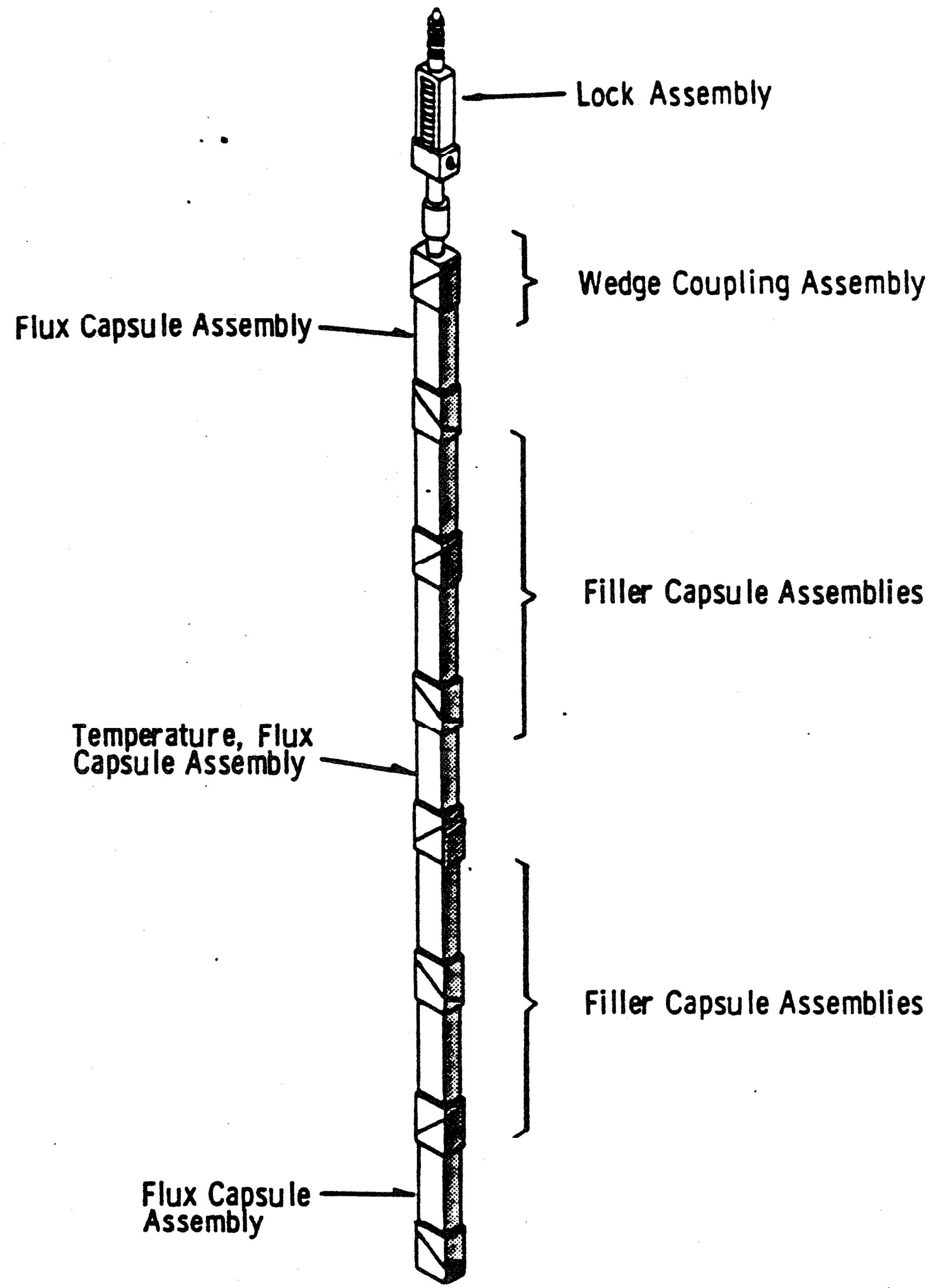
LOCATIONS OF SURVEILLANCE CAPSULE ASSEMBLIES

FIGURE 5.4-2



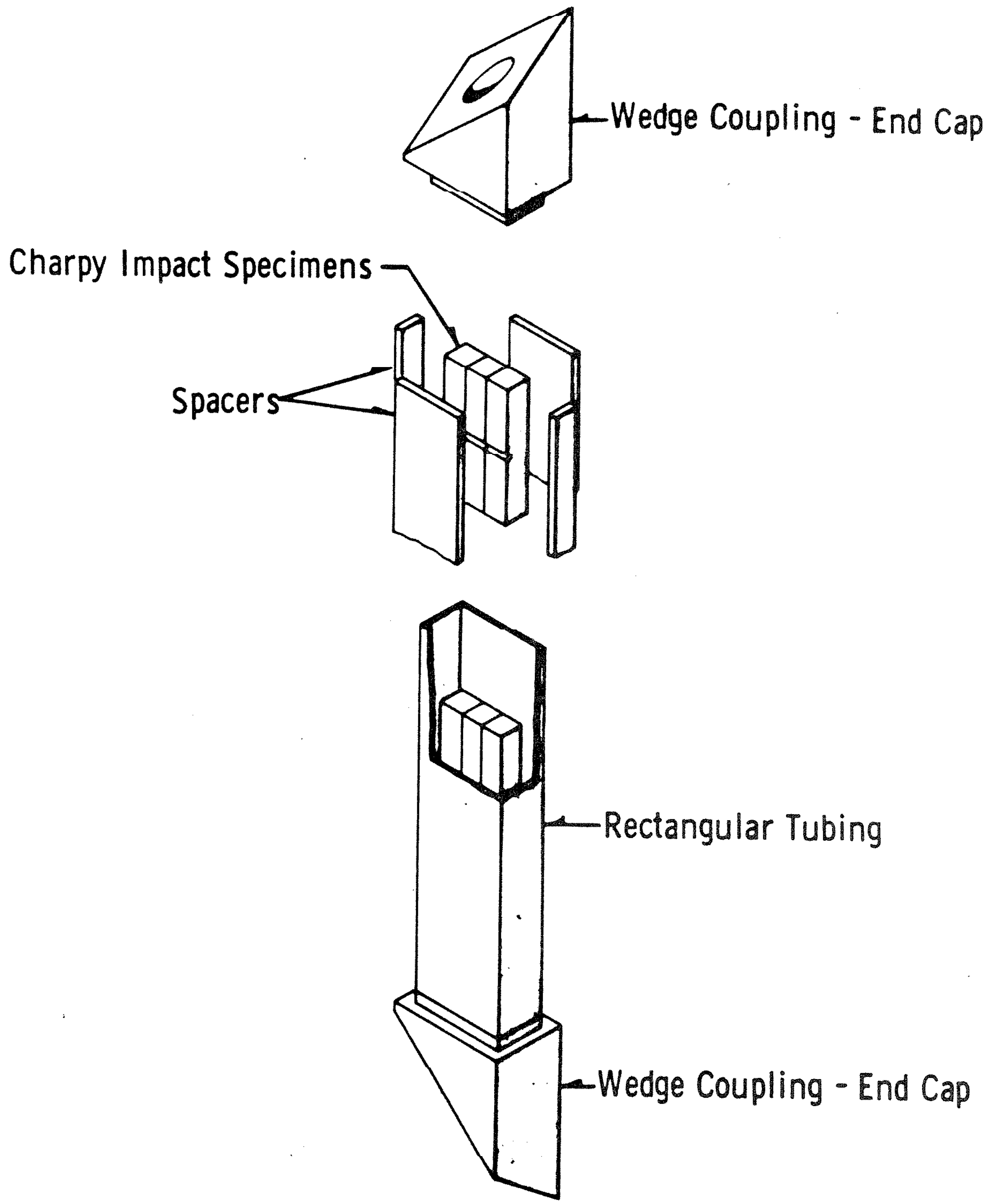

Am. 3-7/85

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>St. Lucie Plant | Typical Surveillance Capsule Assembly | Figure<br>5.4-3a |

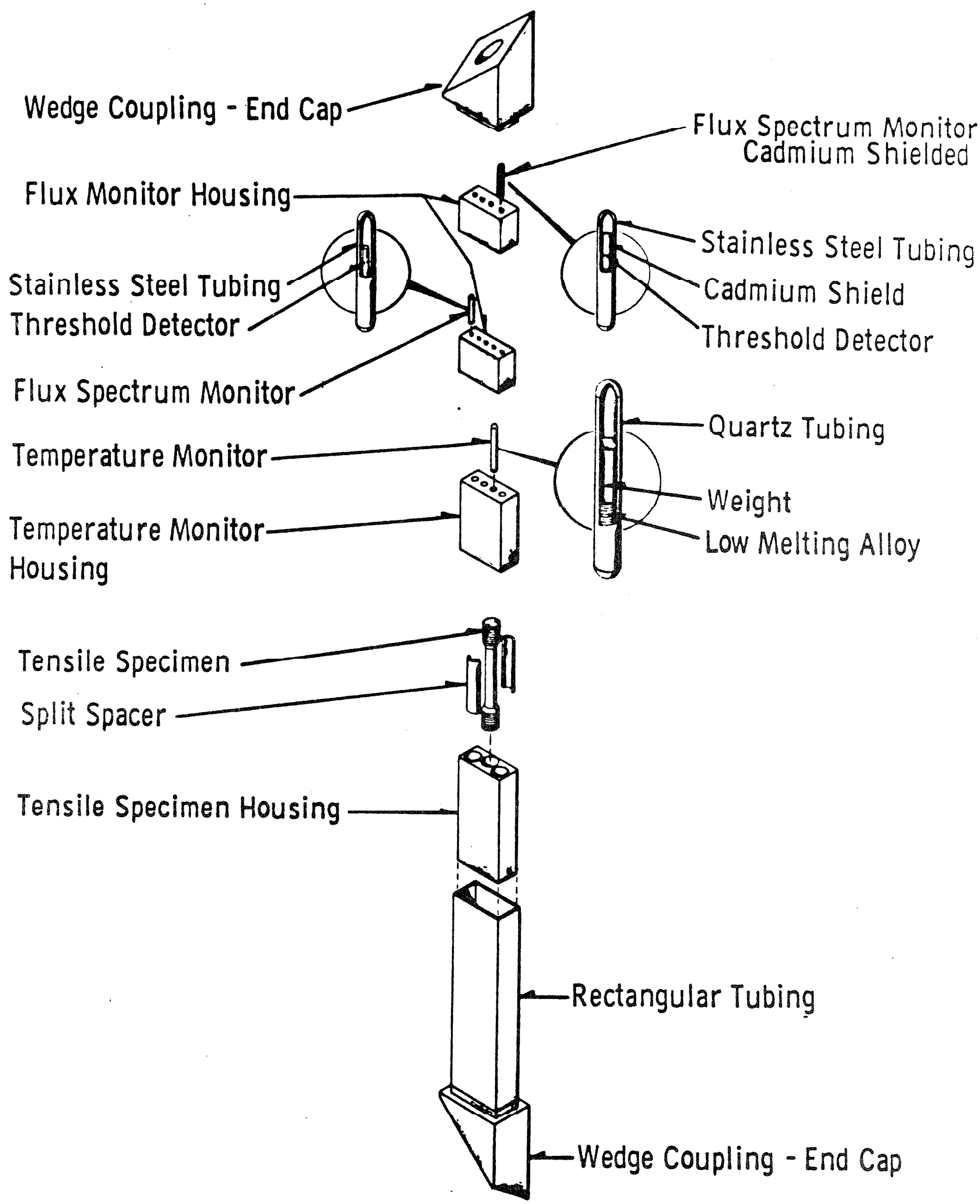



Am. 3-7/85

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>St. Lucie Plant<br>Unit 1 | REPLACEMENT SURVEILLANCE CAPSULE ASSEMBLY | Figure<br>5.4-3b |




| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Typical Charpy Impact Compartment Assembly | Figure 5.4-4 |
|---|---|---|




| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Typical Tensile-Monitor Compartment Assembly | Figure 5.4-5 |

## 5.5 COMPONENT AND SUBSYSTEM DESIGN

### 5.5.1 STEAM GENERATOR

#### 5.5.1.1 Design Bases

The steam generators are designed to:

a) Transfer the heat generated in the reactor coolant system to the secondary system.

b) Provide steam with a moisture content no greater than 0.10 percent at design flow.

c) In addition to the transients listed in Section 5.2.1, each steam generator is also designed for the following conditions: (Note: Differences exist between the cycles and transients assumed in the design of Unit 1 and those assumed in the design of Unit 2. Further, there may also be unit differences with respect to those cycles and transients required by plant procedure to be tracked.)

   1) 4000 cycles of transient pressure differentials of 85 psi across the divider plate caused by starting and stopping the reactor coolant pumps.

   2) Ten cycles of hydrostatic testing of the secondary side at 1235 psig.

   3) 200 cycles of leak testing of the secondary side at 985 psig.

   4) 15,000 cycles of adding 600 gpm of 70°F feedwater with the plant in hot standby condition.

   5) OBE 200 occurrences.

d) Ensure that critical vibration frequencies will be well out of the forcing function frequency range expected during normal operation and during abnormal conditions.

e) An emergency transient of eight cycles of adding a maximum of 650 gpm of 32°F feedwater with the steam generator secondary side dry and at 610°F and secondary side pressure at atmosphere.

f) Faulted Conditions (Level D) as follows:

   1) Safe Shutdown Earthquake + Normal Operation — 1 occurrence

   2) Safe Shutdown Earthquake + Normal Operation + RCS Pipe Rupture — 1 occurrence

   3) Safe Shutdown Earthquake + Normal Operation + MSLB Pipe Rupture — 1 occurrence

   4) Safe Shutdown Earthquake + Normal Operation + FWLB Pipe Rupture — 1 occurrence

#### 5.5.1.2 Description

The nuclear steam supply system utilizes two steam generators (Figure 5.5-1) to transfer the heat generated in the reactor coolant system to the secondary system. The design parameters for the steam generators are given in Table 5.5-1.

The steam generator is a vertical U-tube heat exchanger with the reactor coolant on the tube side and the secondary fluid on the shell side.

Reactor coolant enters the steam generator through the 42 inch ID inlet nozzle, flows through 3/4-inch OD 0.045 inch wall U-Tubes, and leaves through two 30-inch ID outlet nozzles. Divider plates in the lower head separate the inlet and outlet plenums. The plenums are a carbon steel forging with stainless steel clad; the reactor coolant side of the tube sheet is Ni-Cr-Fe clad. The U-tubes are given Inconel composition Alloy 690. The tube-to-tube sheet joint is welded on the primary side before the tubes are hydraulically expanded in the tube sheet holes.

Feedwater enters the steam generator through the 18-inch feedwater nozzle where it is distributed via a feedwater distribution ring having top apertures which direct flow to the downcomer. The downcomer is the annular passage formed by the inner surface of the steam generator shell and the cylindrical shell which encloses the vertical U-tubes.

A steam generator low level transient can be caused by the following mechanisms:

a) Plant transients resulting in a reactor trip

b) Steaming rate greater than feedwater flow:

    1) during manual control

    2) due to malfunction of feedwater control

c) A large load rejection (100% power to 50% or lower).

The potential for feedwater instability was initially considered in the design of the feedwater piping system. Routing of feedwater piping is such that draining of the feedwater line is minimized. An isometric of St. Lucie Plant Unit 1 secondary feedwater piping is provided as Figure 5.5-12.

The replacement steam generator (RSG) design is cognizant of industry problems with feedwater distribution systems due to waterhammer, thermal stratification, erosion and internal feedwater header collapse. The RSG distribution system satisfies all the current (at the time of design) NRC recommendations with respect to waterhammer, provides flow stratification mitigation and addresses industry concerns regarding corrosion, corrosion cracking, thermal fatigue and material erosion. Furthermore, the RSG allows for physical access to the feedwater header region through tunnels and ladders at each drum manway location.

At the bottom of the downcomer, the secondary water is directed upward past the U-tubes where heat transferred from the reactor coolant side produces a steam water mixture.

Upon rising above the U-tube heat transfer surface, the steam water mixture enters centrifugal type separators. These impart a centrifugal motion to the mixture and separate the water from the steam. The water leaves the separator through the separator return cylinder and flows by gravity into the downcomer where it is mixed with the feedwater. Final drying of the steam leaving the primary separators is accomplished by passing the steam through secondary cyclone separators. The moisture content of the outlet steam is no greater than 0.1 percent at design flow.

The steam generator shell is constructed of ferritic steel plate and forgings. Manways and handholes provide access to the steam generator internal structure. Manways on the inlet and outlet of the reactor coolant side permit access to the tube sheet for inspection and tube plugging if required.

The steam generators are mounted on bearing plates which allow controlled lateral motion due to thermal expansion of the reactor coolant piping. Key stops embedded in the concrete base limit this motion in case of a coolant pipe rupture. The top of each unit is restrained from sudden lateral movement by keys and hydraulic snubbers mounted rigidly to the concrete structure.

The steam generators are located at a higher elevation than the reactor vessel. The elevation difference creates natural circulation capability sufficient to remove core decay heat following coastdown of all reactor coolant pumps.

Overpressure protection for the shell side of the steam generators and the main steam line up to the inlet of the turbine stop valve is provided by sixteen flanged spring loaded ASME Code safety valves which discharge to atmosphere. Eight of these safety valves are mounted on each of the main steam lines upstream of the steam line isolation valves but outside the containment. The opening pressure of the valves is set in accordance with ASME Code allowances. Periodic Inservice Testing of the Main Steam Safety Valves (MSSVs) for lift setpoint verification is required by plant Technical Specifications in accordance with the Inservice Testing Program. MSSV setpoint verification testing is allowed while in Modes 1-3. The valves can pass a steam flow equivalent to an NSSS thermal power level of 3034 MWt at the nominal set pressure. Parameters for the main steam safety valves are given in Table 5.5-2.

Steam flow from each steam generator is measured by venturi pipe flow elements in each steam line within the containment. The flow elements also serve as flow restrictors in the event of a postulated steam line break. Design data for the venturis is given on Table 10.1-1. An integral flow restrictor is also provided in the steam outlet nozzle of the replacement steam generator.

### 5.5.1.3 Evaluation

Each replacement steam generator (RSG) is designed for the transients listed in Sections 5.2.1 and 5.5.1.1 according to the requirements of the ASME Code, Section III. Normal and upset conditions (Levels A&B) are evaluated considering both stress limits and cyclic fatigue according to the Code. The cumulative usage factor is less than 1.0. Emergency and faulted conditions Levels C&D are evaluated according to their respective Code allowable stresses and to ensure structural integrity and safe shutdown of the RSGs.

The steam generator has also been designed to ensure that critical vibration frequencies will be well out of the forcing function frequency range expected during normal operation and during abnormal conditions. The steam generator tubing and tubing supports are designed and fabricated with consideration given to both secondary side-flow induced vibrations. In addition, the heat transfer tubing and tube supports are designed such that they will not be structurally damaged under the loss of secondary pressure conditions that may produce a fluid velocity, through the steam outlet nozzle, four times the design velocity.

The inservice inspection program to detect tubes with unacceptable wall thickness is described in the Unit 1 Technical Specifications. This program governs the criteria used for tube inspection, tube sample sizes inspection intervals and acceptance criteria.

Should unacceptable tube degradation occur, the integrity of the reactor coolant boundary may be restored by installing a tube plug within the tube or tubesheet hole if removal of the tube is warranted. Should tube degradation occur that indicates potential for tube severance, the tube may have a stake and tube plug installed. If the plugged tube severs, the stake is designed to reduce the possibility of tube-to-tube contact. The stakes, the plugs and their installation are designed to function under all operating, transient or test conditions of the steam generator. This installation takes into consideration maintaining integrity under vibrating loads and material compatibility with tube material subject to both reactor coolant and feedwater system environments.

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## 5.5.2 PRESSURIZER

### 5.5.2.1 Design Bases

The pressurizer is designed to:

a) Maintain reactor coolant system operating pressure.

The pressurizer heaters and spray are sized to maintain reactor coolant pressure during steady state operation as well as during load changes. EPU analyses for uprating of the unit to 3020 MWt demonstrates that pressurizer pressure is maintained above the low pressurizer pressure reactor trip setpoint during the design basis operational transients. Pressurizer heater sizing is demonstrated to be adequate in Figures 5A-8, 5A-12 and 5A-18 of Appendix 5A for Cycle 1. The reactor coolant system pressure is shown to be maintained within ±10 percent of steady state pressure during load changes.

b) Compensate for changes in coolant volume during load changes.

The parameters for sizing the pressurizer include a requirement to maintain level during load changes. New control system settings for the pressurizer level control program as a function of Tavg were implemented for uprating the unit to 3020 MWt. EPU analyses verified that the Pressurizer Pressure Control System, which operates the pressurizer heaters and the spray control valves, in conjunction with the Pressurizer Level Control System, which operates the letdown and charging equipment, maintained control of the RCS pressure and pressurizer level during all of the normal operating transients without causing any plant trips such as high and low pressure trips. The fact that the reactor coolant system volume is compensated for in the pressurizer is shown in Figures 5A-7, 5A-11 and 5A-18 of Appendix 5A for Cycle 1 where the pressurizer level is maintained within the operating band during load changes.

c) Contain sufficient volume to prevent draining the pressurizer as a result of reactor trip or loss of load. EPU analyses for uprating of the unit to 3020 MWt addressed the effects of revised control system settings for the pressurizer level control program as a function of Tavg and other changes that are necessary to the reactor control systems and demonstrated that the changes were consistent with the Pressurizer Level Control System's design basis.

Figure 5A-19 depicts pressurizer level during the over pressure transient used to size the safety valves for Cycle 1. This transient results in pressurizer level going through a swing of over 10 ft. following a reactor trip at about 10 seconds. This is representative of what would be expected following a normal trip on full loss of load. For a 10 ft. swing in level about 3 ft. of water remains in the pressurizer.

d) Limit the water volume to minimize the energy release during LOCA.

The pressurizer is sized through computer simulation to assure that the pressurizer heaters remain covered during all normal operating transients and to assure that the pressurizer is not drained during loss of load or reactor trips. This resultant size is the minimum volume for energy release considerations during LOCA.

e) Prevent uncovering of the heaters by the out-surge of water following load decreases; 10 percent step decrease and 5 percent per minute ramp decrease. EPU analyses for uprating of the unit to 3020 MWt addressed the effects of revised control system settings for the pressurizer level control program as a function of Tavg and other changes that are necessary to the reactor control systems and demonstrated that the changes were consistent with the Pressurizer Level Control System's design basis.

The sizing of the pressurizer such that the heaters are not uncovered is coupled with design bases (b) above. The resultant pressurizer levels associated with load changes are indicated in Figures 5A-11 and 5A-18 of Appendix 5A for Cycle 1. In each case the water level dropped by less than one foot.

f) Provide sufficient volume to accept the reactor coolant in-surge resulting from a loss of load without the water level reaching the safety and power operated relief valve nozzles. EPU analyses for uprating the unit to 3020 MWt addressed the effects of revised control system settings for the Pressurizer level control program as a function of Tavg and other changes that are necessary to the reactor control systems, and demonstrated that the changes were consistent with the Pressurizer Level Control System's design basis.

Figure 5A-19 for Cycle 1 shows the resultant up-surge of about 3 feet. This still leaves approximately 7 feet to act as a pressure cushion.

g) Provide sufficient volume to yield acceptable pressure response to normal system volume changes during load change transients. New control system settings for the pressurizer level control program as a function of Tavg were implemented for uprating the unit to 3020 MWt. EPU analyses verified that the Pressurizer Pressure Control System, which operates the pressurizer heaters and the spray control valves, in conjunction with the Pressurizer Level Control System, which operates the letdown and charging equipment, maintained control of the RCS pressure and pressurizer level during all of the normal operating transients without causing any plant trips such as high and low pressure trips.

The pressurizer pressure response during normal load changes is depicted in Figures 5A-8, 5A-12, and 5A-18 of Appendix 5A for Cycle 1 and is acceptable.

h) Achieve a total coolant volume change and associated charging and letdown flows which are as small as practical and are compatible with the capacities of the volume control tank, charging pumps and letdown control valves during load following transients. EPU analyses for uprating of the unit to 3020 MWt addressed the effects of revised control system settings for the pressurizer pressure control program as a function of Tavg and other changes that are necessary to the reactor control systems, and demonstrated that the changes were consistent with the pressurizer pressure control system's design basis.

The pressurizer level control program is based on pressurizer size to compensate for RCS shrink and swell over changing average reactor coolant temperatures. The level control system provides proportional control to maintain the pressurizer level at the programmed level setpoint as depicted in Figure 5.5-4. The capacities of the chemical and volume control system components are designed to maintain the required reactor coolant system volume as described in Section 9.3.4.

i) Ensure that the minimum pressure observed during transients is above the setpoint of the safety injection actuation signal. EPU analyses for uprating of the unit to 3020 MWt addressed the effects of revised control system settings for the pressurizer pressure control program as a function of Tavg and other changes that are necessary to the reactor control systems, and demonstrated that the changes were consistent with the pressurizer pressure control system's design basis.

During the worst transient for Cycle 1, the pressurizer pressure stabilizes at about 74 percent of the design pressure as can be seen on Figure 5A-20. This pressure is well above the pressure at which the safety injection systems will be activated, which is about 64 percent of the normal design pressure.

Where reference is made to Palisades test results (Appendix 5A), it must be noted that the St. Lucie pressurizers are similar in design to that provided for Palisades. The results, therefore, verify that the pressurizer meets the design bases. As noted in Appendix 5A, the results reported were developed for the licensing of the unit during the design phase, and therefore should be considered historical. For the Extended Power Uprate to 3020 MWt (core power), the NSSS control systems were evaluated and their ability to meet the criteria identified in items (a) through (i) above was confirmed.

5.5.2.2 Description

The pressurizer is shown in Figure 5.5-2 and the design parameters are given in Table 5.5-3.

The pressurizer is a cylindrical carbon steel vessel with stainless steel clad internal surfaces. A spray nozzle on the top head is used in conjunction with heaters in the bottom head to provide level and pressure control. Over pressure protection is provided by three safety valves and two power operated relief valves. The pressurizer is supported by a cylindrical skirt welded to the bottom head. A surge line connects the pressurizer to the reactor coolant piping in loop 1B hot leg.

The pressurizer is designed and fabricated in accordance with the ASME Code listed in Table 5.2-1. The interior surface of the pressurizer is clad with weld deposited stainless steel. The Ni-Cr-Fe alloy heater sleeves are welded to NiCrFe buttering applied to J grooves machined into the cladding and base metal. A stainless steel safe end is provided on the pressurizer nozzles after vessel final stress relief to facilitate field welds to the stainless steel piping.

The total volume of the pressurizer is established by consideration of the factors given in Section 5.5.2.1. To account for these factors and to provide adequate margin at all power levels, the water level in the pressurizer is programmed as a function of average coolant temperature as shown in Figure 5.5-3. High or low water level error signals result in the control actions shown in Figure 5.5-4 and described below.

Pressure is maintained by controlling the temperature of the saturated liquid volume in the pressurizer. At full load conditions, slightly more than one half the pressurizer volume is occupied by saturated water, and the remainder by saturated steam. In order to maintain the programmed pressure the corresponding saturation temperature must be maintained. To maintain this temperature approximately 20% of the 120 installed heaters are kept energized to compensate for heat losses through the vessel and to raise the continuous subcooled pressurizer spray flow to the saturation temperature.

During load changes, the pressurizer limits pressure variations caused by expansion or contraction of the reactor coolant. The average reactor coolant temperature is programmed to vary as a function of load as shown in Figure 5.3-1. A reduction in load is followed by a decrease in the average reactor coolant temperature to the programmed value for the lower power level. The resulting contraction of the coolant lowers the pressurizer water level causing the reactor system pressure to decrease. This pressure reduction is partially compensated by flashing of pressurizer water into steam. All pressurizer heaters are automatically energized on low system pressure, generating steam and further limiting pressure decrease. Should the water level in the pressurizer drop sufficiently below its setpoint, the letdown control valves close to a minimum value and additional charging pumps in the chemical and volume control system are automatically started to add coolant to the system and reactor pressurizer level.

When steam demand is increased, the average reactor coolant temperature is raised in accordance with the coolant temperature program. The expanding coolant from the reactor coolant piping hot leg enters the bottom of the pressurizer through the surge line, compressing the steam and raising system pressure. The increase in pressure is moderated by the condensation of steam during compression and by the decrease in bulk temperature in the liquid phase. Should the pressure increase be large enough, the pressurizer spray valves open, spraying coolant from the reactor coolant pump discharge (cold leg) into the pressurizer steam space. The relatively cold spray water condenses some of the steam in the steam space, limiting the system pressure increase. The programmed pressurizer water level is a power dependent function. A high level error signal produced by an in-surge causes the letdown control valves to open, releasing coolant to the chemical and volume control system and restoring the pressurizer to the prescribed level. Small pressure and coolant volume variations are accommodated by the steam volume which absorbs flow into the pressurizer and by the water volume which allows flow out of the pressurizer.

The pressurizer heaters are single unit, direct immersion heaters which protrude vertically into the pressurizer through sleeves welded in the lower head. Each heater is internally restrained from high amplitude vibrations and can be individually removed for maintenance during plant shutdown.

Approximately 20 percent of the heaters are connected to proportional controllers which adjust the heat input as required to account for steady state losses and to maintain the desired steam pressure in the pressurizer. The remaining backup heaters are connected to proportional on-off controllers. These heaters are normally deenergized but are turned on by a low pressurizer pressure signal or high level error signal. This latter feature is provided since load increases result in an in-surge of relatively cold coolant into the pressurizer thereby decreasing the temperature of the water volume. The action of the chemical and volume control system in restoring the level results in a pressure undershoot below the desired operating pressure. To minimize the pressure undershoot, the backup heaters are energized earlier in the transient, contributing more heat to the water before the low pressure setting is reached. An interlock will prevent operation of the backup heaters if the high level error signal occurs concurrent with a high pressurizer pressure signal. A low-low pressurizer level signal deenergizes all heaters to prevent heater burnout.

The pressurizer spray is supplied from two of the reactor coolant pump cold legs discharges to the pressurizer spray nozzle. Automatic spray control valves control the amount of spray as a function of pressurizer pressure; both of the spray control valves function in response to the signal from the controller. These components are sized to use the differential pressure between the pump discharge and the pressurizer to pass the amount of spray required to prevent the pressurizer steam pressure from opening the power operated relief valves during normal load following transients. A small continuous flow is maintained through the spray lines at all times to keep the spray lines and the surge line warm to reduce thermal shock during plant transients. The continuous flow also aids in keeping the chemistry and boric acid concentration of the pressurizer water the same as that of the coolant in the heat transfer loops. An auxiliary spray line is provided from the charging pumps to permit pressurizer spray during plant heatup, or to allow cooling if the reactor coolant pumps are shut down.

In the event of an abnormal transient which causes a sustained increase in pressurizer pressure, at a rate exceeding the control capacity of the spray, a high pressure trip level will be reached. This signal trips the reactor and opens the two power-operated relief valves. The steam discharge by the relief valves goes to the quench tank where it is condensed.

5.5.2.3 Evaluation

It is shown by analysis made in accordance with the requirements for Section III Class A vessels that the pressurizer is adequate for all normal operating and transient conditions expected during the life of the plant.

5.5.2.4 Testing and Inspection

Following shop fabrication, the pressurizer is subjected to the hydrostatic test required by Section III of the ASME Code. Upon completion of field erection of the reactor coolant system, the system is hydrotested to verify the pressure retaining capability of the field welds.

Prior to plant startup, the transient performance of the pressurizer is evaluated by determining system normal heat losses, and maximum pressurization and depressurization rates. This data is used to set the pressure controllers and verify the adequacy of the pressurizer level control system, heaters and spray valves.

Further assurance of the structural integrity of the pressurizer during plant life will be obtained from inservice inspections performed in accordance with ASME Code Section XI and described in Section 5.2.5.

### 5.5.3 VALVES

#### 5.5.3.1 Design Bases

In addition to the drain, vent and root valves in the reactor coolant system, the following valve functions are required:

a) pressurizer safety valves to provide overpressure protection;

b) power operated relief valves:

- to relieve sufficient steam during abnormal transients to prevent opening of the reactor coolant system safety valves; and

- to relieve RCS pressure during low temperature transients with a water solid pressurizer (also see Section 5.2.5.6); and

c) spray valves to suppress pressure increases caused by reactor coolant system transients.

#### 5.5.3.2 Description

The reactor coolant system has three safety valves to provide overpressure protection. The design parameters are given in Table 5.5-4. These valves which are flange mounted on the top of the pressurizer, are totally enclosed, back pressure compensated spring loaded safety valves meeting ASME Code requirements.

The safety valves pass sufficient pressurizer steam to limit the reactor coolant system pressure to 110 percent of design 2750 psig following a complete loss of turbine generator load without simultaneous reactor trip. A delayed reactor trip is assumed on a high pressurizer pressure signal. To determine maximum steam flow through the pressurizer safety valves, the main steam safety valves are assumed to be operational. Values for the system parameters, delay times, and core moderator coefficient are given in Chapter 15.

There are two power operated relief valves in the reactor coolant system. The design parameters are given in Table 5.5-5.

The valves are solenoid-operated power relief valves. The two half-capacity valves are located in parallel pipes which are connected to the pressurizer relief valve nozzle on the inlet side and to the relief line piping to the quench tank on the outlet side. A motor actuated isolation valve is provided upstream of each of the relief valves to permit isolating the valve for maintenance or in case of valve failure. The design parameters for the isolation valves are given in Table 5.5-6. To meet the requirements of paragraph 2.1.1 of Reference 1 for maintaining operability of these valves following loss of offsite power, the power operated relief valves (V1402, V1404) are supplied from Class 1E dc power and the motor-actuated isolation valves (V1403, V1405) are supplied by Class 1E ac power. See Sections 8.3.1 and 8.3.2.

The two power operated relief valves relieve sufficient pressurizer steam during abnormal transients to prevent opening of the reactor coolant system safety valves. The relief valves are actuated by the high reactor coolant system pressure trip signal. The Overpressure Mitigating System (OMS) uses these valves to relieve pressure in a low range, low temperature condition to protect the reactor coolant system from exceeding the Nil Ductibility Transition Temperature. The valves operate to reduce reactor coolant system pressure for two cases. The first is to relieve pressures above 350 psia when RCS cold leg (Tc) temperatures are less than or equal to 200°F during a cooldown, heatup or isothermal conditions. The second case is for pressures greater than 530 psia when Tc is between 215°F and 281°F during a cooldown or between 200°F and 300°F during cooldown, heatup or isothermal conditions.

The capacity of the power operated relief valves has been selected to pass the maximum steam surge associated with a continuous CEA withdrawal starting from low power. Assuming that a reactor trip is effected on a high pressure signal, the capacity of the power operated relief valves prevents the opening of pressurizer safety valves. The total relief valve capacity is also large enough that the safety valves do not open during a loss of load from full power. This assumes normal operation of the pressurizer spray system, and reactor trip on high pressurizer pressure.

Per Generic Letter 90-06 (References 2 & 3), the following requirements apply to the PORVs and PORV Block Valves (V1402, V1403, V1404, and V1405):

1) these valves are Class 1 and are to be included in the QA program for maintenance and procurement;

2) these valves are to be included within the scope of the ASME Section XI, Subsection IWV, for inservice testing; and

3) the PORV block valves are to be included in the Motor Operated Valve (MOV) testing program per Generic Letter 89-10, “Safety Related Motor Operated Valve Testing and Surveillance”.

There are two full capacity spray valves in the reactor coolant system. The design parameters are given in Table 5.5-7. The spray valves are located near the top of the pressurizer and are isolable for maintenance. The pressurizer spray valves and heaters are automatically operated by the pressurizer pressure control channel during load changes and expected transients.

The pressurizer spray flow is a function of the available reactor vessel pressure drop and spray line and component sizing. Based on the available reactor vessel pressure drop and reasonably sized lines and components, it was determined that a value of 375 gpm was available for spray flow. This value was utilized in computerized transient calculations and found to be acceptable in preventing plant trips due to overpressure conditions for various plant load follow requirements.

5.5.3.3 Evaluation

The position of each valve on loss of actuating signal (failure position) is selected to ensure safe operation of the system and plant. System redundancy is considered when specifying the failure position of any given valve. Valve position indication is provided on the control panel for each of these valves necessary to ensure safe operation of the plant.

Manually operated valves in the reactor coolant system have backseats to limit stem leakage when in the open position. Globe valves are installed with flow entering the valve under the seat. This arrangement will reduce stem leakage during normal operation or when closed.

The design bases and actuator capabilities for V1403 and V1405 have been reviewed in accordance with the requirements of Generic Letter 89-10, "Safety Related Motor Operated Valve Testing and Surveillance", as noted in Section 3.9.2.4.

The overpressure protection provisions for the reactor coolant system are described in Section 5.2.2 and in Appendix 5A.

The NRC Staff, per Generic Letter 90-06, identified actions to enhance the reliability of the PORVs and PORV block valves that perform safety related functions. For St. Lucie, the PORVs perform the safety related function of providing low temperature overpressure protection for the reactor coolant pressure boundary as discussed in Section 5.2.2.6. The PORVs are not credited with performing any accident mitigation function, nor are they relied upon to cool down the plant. Therefore, the exception from PORV testing in Modes 3 or 4 as required by Generic Letter 90-06 was accepted by the NRC in Reference 3.

## 5.5.4 QUENCH TANK

### 5.5.4.1 Design Bases

The quench tank is designed to prevent release of the pressurizer safety and relief valves discharges to the containment.

### 5.5.4.2 Description

The quench tank, shown on Figure 5.5-5, is located on floor level 62 feet which is lower than the pressurizer safety or relief valves to ensure that any leakage or discharge from the valves drains to the quench tank. The tank is designed and fabricated in accordance with the ASME Code Section III Class C. The design parameters are given in Table 5.5-8.

The tank contains demineralized water under a positive nitrogen overpressure. The sparger, spray header, nozzles and rupture disc fittings are stainless steel. The steam discharged into the quench tank from the pressurizer valves is discharged under water by the sparger to enhance condensation. The quench tank normal water volume of 127 cubic feet is sufficient to condense 1440 pounds of steam released from the pressurizer safety and relief valves as a result of a loss of load followed immediately by an uncontrolled rod withdrawal with no coolant letdown or pressurizer spray. The water temperature in the quench tank is limited to 281°F based on initial water temperature of 120°F. The tank gas volume is sufficient to limit the maximum tank pressure to 70 psig after the steam release produced by this sequence of events. EC284136

The contents of the quench tank are cooled by the addition of reactor makeup water. Quench tank water level indication and high and low water level alarms are provided in the Control Room along with the pressure and temperature indicators and alarms. EC284136

Leakage or discharge from the safety or relief valves is indicated and alarmed in the control room by temperature measurements in each valve pipe line to the quench tank header.

The historical quench tank sizing analysis, which combines the steam releases for two separate events, is unnecessarily conservative. It is sufficient to verify that the capacity of the quench tank to condense the steam releases for the bounding loss of load or uncontrolled rod withdrawal event analyses is adequate when each event is considered separately. Treating each event separately is acceptable when it is considered that each event (the loss of load event and the uncontrolled rod withdrawal event) are terminated by a reactor trip. This evaluation method is in accordance with the SRP Section 5.4.11.

Analyses for uprating of the unit to 3020 MWt included a loss of load analysis as well as an evaluation of the limiting steam release for an uncontrolled rod withdrawal event. The uncontrolled rod withdrawal event re-evaluated the historical transient using limiting design values for the Doppler coefficient, moderator temperature coefficient, and control element assembly withdrawal reactivity.

Each of these event steam releases was compared to the original design basis mass of 1440 pounds of steam to determine if the steam could be successfully condensed without challenging the quench tank rupture disk.

The bounding steam release for the loss of load event analysis was determined to be 546 pounds of steam passed by the pressurizer safety valves. The bounding steam release for the uncontrolled rod withdrawal event evaluation was determined to be bounded by the 830 pounds of steam passed by the pressurizer relief valves in the historical transient analysis.

Each of these steam releases is less than the design basis mass of 1440 pounds of steam that could be successfully condensed without challenging the quench tank rupture disk or the historical design basis of the quench tank associated components. The capacity of the quench tank to condense the steam releases for the bounding loss of load event and the bounding uncontrolled rod withdrawal EPU event analyses for uprating of the unit to 3020 MWt is such that the steam releases can be successfully condensed without challenging the quench tank rupture disk. Therefore, the current quench tank water level and temperature limits can be maintained.

5.5.4.3 Evaluation

Evaluations beyond the requirements of ASME Code, Section III, include the tank head in accordance with Welding Research Council Bulletin #95. Compliance with this reference results in a tank head which is thicker than Section III design methods.

The seismic analysis of the quench tank ensures tank or support failures will not occur during a DBE and the natural frequency is greater than 20 cps to preclude resonance. Besides these evaluations, the tank sparger is analyzed for both seismic forces and blowdown forces. These additional evaluations ensure that the quench tank will withstand these accident related conditions.

## 5.5.5 REACTOR COOLANT PUMPS

### 5.5.5.1 <u>Design Bases</u>

The reactor coolant pumps which circulate the reactor coolant through the reactor coolant system are designed to:

a) Circulate reactor coolant with the chemistry identified in Table 9.3-8 at the flows listed in Table 5.5-9.

b) Meet the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class A. Winter 1967 Addenda.

c) Meet the transient operating condition categories listed in Section 5.2.1.2.

d) Provide sufficient moment of inertia to reduce the flow decay through the core upon loss of pump power.

e) Prevent reverse rotation of the pump upon loss of pump power with the other pumps operating.

f) Operate without cooling water for periods up to 10 minutes without incurring seal damage.

Reactor coolant pump parameters and design requirements are listed in Table 5.5-9.

### 5.5.5.2 <u>Description</u>

The reactor coolant is circulated by four vertical, single bottom suction, horizontal discharge, centrifugal motor driven pumps as shown in Figure 5.5-6. The design parameters for the pumps are given in Table 5.5-9.

The reactor coolant pump assembly consists of the pump case, rotating assembly containing the impeller which is keyed and locked to the shaft, pump case cover, motor adapter and motor. The motor is connected to and supported by the pump case through the motor mount adapter. There are two openings on opposite sides of the motor mounts that provide access for assembly of the flanged rigid coupling between the motor and pump and for seal cartridge replacement.

The pump rotating assembly consists of impeller, water lubricated radial hydrostatic bearing rotor, seal coolant recirculating impeller and rotating elements of the seal cartridge assembly. The radial bearing, one of three used for pump motor shaft support, is located just above the pump impeller. The upper radial bearing and the axial thrust bearing are located on the motor shaft. The seal cartridge and recirculating impeller are located above the thermal barrier formed by the close clearance between the pump shaft and the pump case cover.

The pump case cover assembly includes the coiled tubing heat exchanger which cools the seal cartridge and thermal barrier, the seal cartridge assembly, the thermal barrier, the radial bearing stator and the upper and lower impeller labyrinth seals.

The seal cartridge consists of four face type mechanical seals; three full pressure seals mounted in tandem and a fourth low pressure vapor seal designed to withstand system operating pressure when the pumps are not operating. A controlled bleedoff flow through the seals is used to cool the seals and to equalize the pressure drop across each seal. The controlled bleedoff flow is collected in the volume control tank of the chemical and volume control system. Leakage past the vapor seal is collected in the reactor cavity sump.

The seal cartridge assembly is cooled by circulating the controlled leakage through a coiled tube heat exchanger integral with the pump case cover. The seal coolant recirculation is done by the recirculating impeller located directly below the seal cartridge. The seals are capable of operation without cooling water for up to ten minutes without incurring damage. The seal cartridge concept reduces the time required for seal maintenance thereby lowering personnel radiation exposure time. The seal cartridge can be removed without draining the pump case. Details of the seal cartridge are shown on Figure 5.5-8.

The seal design life is at least two years. Each seal is designed to accept the full operating pressure of the reactor coolant system, however, the first three seals of the cartridge assembly normally operate with a pressure differential equal to one-third of the operating pressure and with only a slight pressure differential across the vapor seal. The rotating seal faces are tungsten carbide or silicon carbide operating against composite carbon stationary seal faces.

The reactor coolant pump and motor assembly is supported by spring hangers attached to the four support lugs welded to the pump case. The spring hangers permit motion in the horizontal and vertical direction to compensate for thermal and seismic movement.

A RCP lube oil collection system is provided for each pump which will prevent a lube oil fire from propagating or damaging any safe shutdown equipment (see Figure 5.5-14). The system consists of collection pans, drain piping and a collection tank, all of which are seismically supported. Drain lines are prevented from coming in contact with hot reactor coolant piping.

The pump motor assembly includes once through air cooler, motor and pump seal coolant heat exchangers, bearing lubrication and lube oil cooling systems, oil lift pumps, motor-pump shaft upper radial and axial support bearings, flywheel, and anti-rotation device. The motor coolers cooling water is supplied from the component cooling system. Two 10 HP ac oil lift pumps are used to support the pump-motor shaft assembly during startup and shutdown of the pumps. The motor-pump bearing support system includes a Kingsbury double acting thrust bearing and a radial hydrostatic bearing located above the pump impeller. The flywheel and motor-pump rotating assembly has a total moment of inertia of 100,000 lbm-$ft^2$ sufficient to improve the cooldown characteristics of the pumps to meet the system requirements during a loss of pump power condition. The motor flywheel assembly is shown on Figure 5.5-11.

In conjunction with the loss of pump power condition, the pumps include an anti-rotation device shown on Figure 5.5-9 to preclude reverse rotation caused by backflow through the impeller. The device will stop the pump when it decelerates from normal speed (900 rpm) to zero speed while the remaining pumps continue to operate. The anti-reverse device consists of a rotating disc keyed to the motor shaft, and a stationary disc which is bolted to the motor frame. The stationary disc contains several detents each with ramped sides and flats on top of the detents and in the troughs between them. The rotating elements contain several holes in which the retaining pins are located. When pump rotation stops, each pin drops to the flat between detents, and reverse rotation is prevented by the pin which bears against the vertical side of a detent. When motor rotation is started in the normal direction the pins ride up the ramped side of the detents and are locked against the sides of the holes in the rotating disc by centrifugal force. No parts are in contact when the motor is operating at rated speed and no lubrication is required for the device. One pin is capable of holding the pump stationary against the torque produced by reverse flow or by the application of 100 percent voltage in reversed phase rotation.

The expected pump performance curve is shown on Figure 5.5-10. The pump motor is sized for continuous operation at the flows resulting from four-pump operation or partial pump operation with 0.74 specific gravity water. The motor service factor is sufficient to allow 500 heatup cycles during which the nominal horsepower load will decrease from 5700 to 4300 over a period of 7 hours. The motors are designed to start and accelerate to speed under full load when 80 percent or more of their normal voltage is applied. The motors are contained within NEMA standard NG-1-1.20 drip proof enclosures and are equipped with electrical insulation suitable for a zero to 100 percent humidity and radiation environment of 30R/hr of gamma.

5.5.5.3 Evaluation

On October 27, 1971, the AEC issued Safety Guide 14, "Reactor Coolant Pump Flywheel Integrity", which established criteria found acceptable by the regulatory staff. The desirability of additional material testing beyond that required earlier is identified in the guide.

The flywheel for the reactor coolant pumps were the subject of considerable interest during the construction permit review, and the program for qualifying these was described in the Amendment 3 to the PSAR, in response to AEC question 3.19. This program was approved at the time prior to issuing of the Construction Permit. The flywheels and pumps were built in accordance with those requirements.

The selection of material, machining and manufacturing operations, quality control, and the acceptance criteria established to assure the integrity of the flywheel and to minimize operating stresses included the following:

For RCP motor serial numbers 40574-1 through 40574-4: EC293839

a) Nil ductility transition temperatures of SA-516 GR-70 flywheel material is no greater than 40F by dropweight tests. This material meets the Charpy impact test values of 30 ft.-lbs. at 10F based on longitudinal test specimens;

b) The principal stress is not greater than 50 percent of the yield stress (based on transverse test specimens taken at 1/4 thickness) of the flywheel material at normal operating speed not considering keyway stress concentration factors. Minimum keyway fillet radius is 1/8 inch;

c) Where the bore in the flywheel was flame cut, at least 1/2 inch of stock was left on the radius for machining to final dimensions;

d) During manufacture the flywheel material was subjected to 100 percent volumetric ultrasonic inspection from the flat surface per ASME Section III, Para. N-321. Indication greater than 4 inches diameter was cause for rejection per ASTM A435. Indications of complete loss of back reflection greater than one crystal diameter and less than four inch diameter were tested by angle beam technique. Indication greater than a three percent notch was cause for rejection.

e) The flywheel was subjected to a magnetic particle or liquid penetrant examination in accordance with ASME Code Section III, Para. N-321 before assembly of flywheel plates. This inspection was done on both plate surfaces to a distance of eight inches minimum beyond the final bore diameter and after machining in the bore. The acceptance standard for the inspection was as follows:

Indications of cracks and defects were subject to rejection. A linear defect is one in which the length is three times the width. The minimum length of defects considered linear was 3/16 inch.

f) No stress concentrations such as stencil marks, center punch marks, or drilled or tapped holes within eight inches of the edge of the largest flywheel bore were allowed.

The flywheel material, which is pressure vessel quality, vacuum improved steel plate meets the requirements of ASTM-A-516 Grade 70. EC293839

The Charpy values measured for the flywheel material at 40°F are substantially higher than the data compiled on SA-516 grade 70 material by the Research & Product Development Department of Combustion Engineering, Inc. The C-E report titled, "Longitudinal and Transverse Charpy-V-Notch Impact and Dropweight Test Data for Normalized and Tempered SA-516 Grade 70 Material," issued on August 26, 1971, and further identified by Lab. No. X-24053 and R&PD Project No. 420001, was prepared for the Industrial Cooperative Program of the Material Division of the Pressure Vessel Research Committee of the Welding Research Council.

This indicates that the toughness properties of these wheels are better than typical SA-516 Grade 70. Therefore the NDT is lower than the highest value of -10°F reported in that report. Using this value for NDT and lower bound toughness curve contained in ASME Boiler and Pressure Vessel Code, Section III, Summer 1972 Addenda, Appendix G, the toughness $K_{IC}$ of the flywheel material is at least 67 KSI $\sqrt{IN}$ at 70°F and 90 KSI $\sqrt{IN}$ at 100°F.

Since the normal operating temperature of the flywheel is approximately 100°F, a substantial margin exists between the computed $K_I$ for large hypothetical cracks, and the toughness $K_{IC}$. The critical crack size therefore is greater than 5 inches from the bore of the wheel.

Crack growth calculations indicate that the number of starting cycles to cause a reasonably small crack to grow to critical size is more than 100,000, which is orders of magnitude greater than the number of cycles expected during the life of the plant.

The loads that are considered for the circulation of the stresses in the flywheel are the combined primary stresses in the flywheel at normal operating speed. They include the stress due to the interference fit on the shaft as well as the stress due to centrifugal force.

Normal operating speed of the flywheel is 900 rpm. The flywheel has a design overspeed of rated rpm plus 25 percent which equals 1125 rpm. The maximum tangential stress in the flywheel at normal operating speed is 30 percent of the material yield strength. The maximum tangential stress in the flywheel at design overspeed is 40 percent of the material yield strength. Actual overspeed testing was not performed.

The reactor coolant pump flywheels will be accessible for 100 percent in place volumetric ultrasonic examination during in-service inspection periods. An access panel is provided on the outside of each reactor coolant pump motor for conducting the UT examination.

In-service inspection will be performed in accordance with the guidelines of NRC Regulatory Guide 1.14, Revision 1, August 1975. The inspection program for each flywheel includes the following:

a) An in-place ultrasonic volumetric examination of the areas of higher stress concentration at the bore and keyway at approximately 3 year intervals, during the refueling or maintenance shutdown coinciding with the inservice inspection schedule as required by the ASME Boiler and Pressure Vessel Code Section XI.

b) A surface examination of all exposed surfaces and complete ultrasonic volumetric examination at approximately 10 year intervals, during the plant shutdown coinciding with the inservice inspection schedule as required by the ASME Boiler and Pressure Vessel Code Section XI. Removal of the flywheel is not required to perform these examinations.

For serial numbers 47125-1 through 47125-4 and 47783:

The material used to manufacture the flywheel was produced by a process that minimizes flaws by a commercially acceptable process such as the vacuum melt and degassing process which provides adequate fracture toughness properties. The acceptance criteria for flywheel design is compatible with the safety philosophy of the reactor coolant pressure boundary criteria as appropriate considering the inherent design and functional requirement differences between the pressure boundary and the flywheel.

a. The nil-ductility transition temperature (NDTT) of the material, as obtained from the dropweight tests (DWT) performed in accordance with the Specification ASTM E208-66T was no greater than 10°F.

b. The Charpy V-Notch (Cv) upper shelf energy level, in the "weak" (WR) direction, as obtained per ASTM A370 was no less than 50 ft.-lbs. A minimum of three Cv specimens were tested from each plate or forging.

c. The minimum fracture toughness of the material at the normal operating temperature of the flywheel is equivalent to a dynamic stress intensity factor KIc (dynamic) of at least 100 Ksi √in. Compliance was demonstrated by either of the following:

   1. Testing of the actual material of the flywheel to establish the KIc (dynamic) value at the normal operating temperature.

   2. Use of a lowerbound fracture toughness curve obtained from tests on the same type of material. The curve was translated along the temperature coordinate until the KIc (dynamic) value of 45 Ksi √in. is indicated at the NDTT of the material, as obtained from dropweight tests. EC293839

d. Each finished flywheel was subjected to a 100 percent volumetric ultrasonic inspection from the flat surface per ASME Code, Section III. This inspection was performed on the flywheel after final machining and overspeed test.

e. The flywheel is flame cut; at least 1/2 in. of stock was left on the outer and bore radii for machining to final dimensions.

f. The flywheel was subjected to a magnetic particle of liquid-penetrant examination per ASME Code, Section III before final assembly. The inspection was performed on finished machine bores, key ways, and on both flat surfaces to a radial distance of eight in. minimum beyond the final largest machined bore diameter but not including small drilled holes. There are no stress concentrations such as stamp marks, center punch marks, or drilled or tapped holes within eight in. of the edge of the largest flywheel bore.

The flywheel is designed to withstand normal operating conditions, anticipated transients, and the design basis loss of coolant accident loadings combined with the safe shutdown earthquake loadings.

The following criteria are satisfied:

a. The combined stresses, both centrifugal and interference, at normal operating speed do not exceed 1/3 of the minimum specified yield strength for the material selected in the direction of maximum stress.

b. The design speed of the flywheel is 125 percent of normal operating speed.

c. The combined centrifugal and interference stresses at design speed are limited to 2/3 of the minimum specified yield strength where design overspeed is 125 percent of normal operating speed.

d. The motor and pump shaft and bearings can withstand any combination of normal operating loads, anticipated transients, and the design basis loss of coolant accident combined with the safe shutdown earthquake. EC293839

e. Each flywheel was tested at design speed, 125 percent of normal operating speed, as defined in 2.b above. Flywheels for motors that were originally supplied for St. Lucie Unit 1 that were subsequently installed on St. Lucie Unit 2 were not tested at the design speed.

f. The flywheel is accessible for 100 percent in-place volumetric ultrasonic inspection. The flywheel motor assembly is designed to allow such inspection with a minimum of motor disassembly.

5.5.5.4 Testing and Inspection

Each reactor coolant pump and motor assembly is full scale tested at the vendor's shops to ensure design requirements are met. The performance of each pump is measured and the impellers are trimmed, if required, to meet the reactor coolant system head and flow requirements.

To ensure the continuing integrity of the flywheels, they will be inspected periodically as part of the inservice inspection program. The reactor coolant pump motor flywheel assembly and inspection ports are shown on Figure 5.5-11.

## 5.5.6 REACTOR COOLANT PIPING

5.5.6.1 Design Bases

The reactor coolant piping is designed to:

a) Meet the anticipated transients listed in Section 5.2.1.2.

b) Include nozzles required for charging, letdown, pressurizer surge spray, and shutdown cooling functions.

c) Provide thermal sleeves on those nozzles which have significant thermal shock effects.

5.5.6.2 Description

The reactor coolant piping consists of two loops which connect the steam generators to the reactor vessel. Each loop consists of 42-inch ID "hot leg" piping connecting the reactor vessel outlets to the steam generator inlets and 30-inch ID piping connecting the steam generator outlets to the reactor coolant pumps and the coolant pumps to the reactor vessel inlets. The two 30-inch piping segments are referred to as the "pump suction leg" and the "cold leg" respectively. A 12-inch schedule 160 surge line connects loop 1B hot leg to the pressurizer. Design parameters for the reactor coolant piping are given in Table 5.5-10.

The reactor coolant piping is designed and fabricated in accordance with the rules and procedures of the ASME Code given in Table 5.2-1. The anticipated transients listed in Section 5.2.1.2 form the basis for the required fatigue analysis to ensure an adequate usage factor.

The reactor coolant piping is fabricated from ASME SA 516-Gr 70 carbon steel mill clad internally with roll bonded ASME SA 240 type 304L stainless steel. A minimum clad thickness of 1/8 in. is maintained. The 12-inch surge line is fabricated from ASTM A351 Gr CF8M, ASME SA-403, WP347; ASME SA-312, TP347 austenitic stainless steel.

Thermal sleeves are installed in the surge line, charging and inlet shutdown cooling nozzles to reduce thermal shock effects from auxiliary systems. Clad sections of piping are fitted with safe ends for field welding to stainless steel components, i.e., the reactor coolant pumps and the surge line.

5.5.6.3 Evaluation

The piping is shop fabricated and shop welded into subassemblies to the greatest extent practicable to minimize the amount of field welding. Welding procedures and operations meet the requirements of Section IX of the ASME Boiler and Pressure Vessel Code. All welds are 100 percent radiographed and liquid-penetrant or magnetic-particle tested and all reactor coolant piping penetrations are attached in accordance with the requirements of ANSI B31.7. Cleanliness standards consistent with nuclear service are maintained during fabrication and erection. There are no dissimilar metal field welds.

Stress corrosion cracking of the stainless steel piping requires the presence of halides, specifically chlorides and fluorides. The reactor coolant chemistry control described in Section 9.3.4 assures that the halide concentration in the reactor coolant system is below the level required for the development of stress corrosion cracking. Other material considerations are addressed in Section 5.2.3.

The transients for the piping design are listed in Section 5.2. The seismic design of the system is described in Section 3.7.

5.5.6.4 Testing and Inspection

Following field erection of the reactor coolant piping, the reactor vessel, steam generators, pressurizer, reactor coolant pump cases and reactor coolant piping are subjected to a hydrostatic test as required by Section III of the ASME Code to verify the pressure containing capability of the field erected components.

In-service inspection is discussed in Section 5.2.5.

## 5.5.7 COMPONENT SUPPORTS

5.5.7.1 Design Bases

The criteria applied in the design of the reactor coolant system supports are that the specific function of the supported equipment be achieved during all normal, earthquake, and LOCA conditions. Specifically, the supports are designed to support and restrain the reactor coolant system components under the combined design basis earthquake and LOCA loadings in accordance with the stress and deflection limits listed in Table 5.2-2.

5.5.7.2 Description

The reactor coolant system support points are illustrated in Figures 5.1-1 and 1.2-11.

a) Reactor Vessel Supports

The reactor vessel is supported by three integral pads at an elevation below the centerline of the vessel nozzles. The integral pads provide vertical vessel support and allow for unrestrained thermal expansion of the vessel.

Keyways located alongside the vertical support pads guide the vessel during thermal expansion and contraction of the reactor coolant system and maintain the vessel centerline.

b) Steam Generator Supports

The steam generator is supported at the bottom by a sliding base bolted to an integrally attached conical skirt. The sliding base rests on low friction bearings which allow unrestrained thermal expansion of the reactor coolant system. Two keyways within the sliding base guide the movement of the steam generator during expansion and contraction of the reactor coolant system and, together with a stop and anchor bolts, prevent excessive movement of the bottom of the steam generator during seismic events and following a LOCA.

A system of keys and snubbers located on the upper end guide the top of the steam generator during expansion and contraction of the reactor coolant system and provide restraint during seismic events and following a LOCA or a steam line break.

c) Reactor Coolant Pump Supports

Each reactor coolant pump is provided with four vertical spring-type hangers which provide support for normal operation and seismic conditions. In addition each pump has a horizontal hydraulic snubber to dampen torsional oscillation of the pump on the main coolant piping under seismic conditions. The support system is designed to accept the piping and pump movements resulting from the normal and abnormal transient operating conditions described in Section 5.2.1.

For the case of pipe break in the pump suction line, two structural stops are provided to limit the pump horizontal motion.

d) Pressurizer Supports

The pressurizer is supported by a cylindrical skirt welded to the pressurizer and bolted to the support structure. The skirt is designed to withstand dead weight and normal operating loads as well as the loads due to earthquakes and LOCA.

e) Valves

All Quality Group A valves are supported by the piping run in which it is installed. Piping supports are located at either side of all valves in the pipe run. For piping 2 inches and under, motor or air operators are restrained to negate the torsional and moment effects their masses would exert on the piping.

#### 5.5.7.3 Evaluation

The reactor coolant system supports are designed to the criteria for load combinations and stresses which are presented in Table 5.2-2. The criteria is used to determine the loads the supports must consider as a result of the effects of pipe rupture and seismic conditions.

For a discussion on the evaluation of RCS components supports for asymmetric LOCA loads see Section 3.6.3.1.

#### 5.5.7.4 Testing and Inspection

Tests were conducted on materials similar to that being used for the reactor vessel and steam generator sliding supports to demonstrate that the maximum static coefficient of friction does not exceed 0.15 at a design loading of 5000 psi. All sliding supports were 100 percent liquid penetrant inspected and machined sockets were 100 percent magnetic particle inspected at the vendor's shops. The steam generator base casting was magnetic particle inspected per ASTM E109-63.

The steam generator snubbers were tested in the vendor's shop at the rated load capacity in both tension and compression. The piston creep velocities were measured during these tests for compliance with specification limits. Tests were also conducted for initiation of snubber action on both the tension and compression directions.

REFERENCES FOR SECTION 5.5


1. NUREG-0578 TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations.

2. Generic Letter 90-06, Resolution of Generic Issue 70, “Power-Operated Relief Valve and Block Valve Reliability”, and Generic Issue 94, “Additional Low-Temperature Overprotection for Light Water Reactors”, June 25, 1990.

3. Letter from Jan A. Norris (NRC) to J.H. Goldberg (FPL), St. Lucie Units 1 & 2 – Response to Generic Letter 90-06, August 20, 1993.

TABLE 5.5-1
STEAM GENERATOR PARAMETERS
DESIGN VALUES

| | |
|---|---|
| Number | 2 |
| Type | Vertical U-Tube |
| Number of Tubes, Nominal | 8523 |
| Tube Outside Diameter, in. | 0.750 |
| Tube Wall Thickness, in. | 0.045 |
| Heat Transfer Rate, each, Btu/hr. | $5.18 \times 10^9$ |
| Nozzles and Manways | |
| Primary Inlet Nozzle (1 ea.), ID, in. | 42 |
| Primary Outlet Nozzle (2 ea.), ID, in. | 30 |
| Steam Nozzle (1 ea.), ID, in. | 34* |
| Feedwater Nozzle (1 ea.), nominal, in. | 18 |
| Instrument Taps (4 ea.), nominal, in. | 1 |
| Water Level Nozzles (12 ea.), nominal, in. (2 capped) | 1 |
| Primary Manways (2 ea.), ID, in. | 18 |
| Secondary Manways (2 ea.), ID, in. | 18 |
| Secondary Handhole (6 ea.), ID, in. | 8 |
| Bottom Blowdown (2 ea.), nominal, in. | 4 |
| Inspection Ports (10 ea.), nominal, in. | 2 |
| Recirculation Nozzle (1 ea.), (capped), nominal, in. | 3 |
| Pressure Tap (1 ea.), (capped), nominal, in. | 1 |
| Reactor Coolant Side | |
| Design Pressure, psig | 2485 |
| Design Temperature, F | 650 |
| Design Thermal Power (NSSS), Core Power Rating Mwt | 3020 |
| Design Coolant Flow (each), lb./hr. | $70 \times 10^6$ |
| Operating Coolant Flow (each), lb./hr. | $77.2 \times 10^6$*** |
| Normal Operating Pressure, psig | 2235 |
| Coolant Volume, each, ft.$^3$ | 1698 |
| Secondary Side | |
| Design Pressure, psig | 985 |
| Design Temperature, F | 550 |
| Normal Operating Steam Pressure, Full Load (3034** Mwt) psia | 864.6 |
| Normal Operating Steam Temperature, Full Load, F | 527 |
| Blowdown Flow, Design, Maximum, Each, lb./hr. | 112,100 (1.7%) |
| Steam Flow, Each, lb./hr. | $6.6 \times 10^6$ |
| Steam Moisture Content, Maximum, percent | 0.10 |
| Design Feedwater Temperature, F | 435 |
| Operating Feedwater Temperature, F | 436.2*** |
| Number of Steam Separators, each | 170 |
| Number of Steam Dryers, each | 170 |
| Tube Sheet Design Differential Pressure, psi | 2250 |
| Dimensions | |
| Overall Height, Including Support Skirt, in. | 749 |
| Upper Shell Outside Diameter, in. | 239 7/8 |
| Lower Shell Outside Diameter, in. | 166 1/4 |

* Steam Nozzle has Informal Flow Restrictor with 26" Bore
** Includes Pump Heat
*** Predicted – Replacement Steam Generators with 0% Plugging at EPU conditions

TABLE 5.5-1 (Cont'd)

STEAM GENERATOR PARAMETERS
DESIGN VALUES

| | |
|---|---|
| Weights | |
| Dry, lb | 1,086,000 |
| Flooded, lb | 1,677,000 |
| Operating, lb | 1,301,300 |

TABLE 5.5-2

MAIN STEAM SAFETY VALVE PARAMETERS

(Tag No's. V8201 through V8216)

| | |
|---|---|
| Design Pressure, psig | 985 |
| Design Temperature, °F | 550 |
| Fluid | Saturated Steam |
| Set Pressure, psia | |
| 8 Valves | 1000 (+3%, -3%) |
| 8 Valves | 1040 (+2%, -3%) |
| Certified Capacity lb./hr. (Ref. Crosby Valve data: 8770-990 R9) | |
| 8 Valves | 743,481 |
| 8 Valves | 773,242 |
| Accumulation, percent | 3 |
| Total Rated Capacity @ 1100 psia, (16 valves) lb./hr. | $12.7 \times 10^6$ |
| Blowdown, percent (maximum) | 8 |
| Maximum backpressure buildup, psia | 25 |
| Materials | ASTM-A-216 |
| Body | Grade WCB |
| Nozzle Seat and Disc Insert | 19-9DL Stainless Steel or equivalent |
| Flanges | |
| Inlet | 6 in. - 1500 lb. ASA |
| Outlet | 10 in. - 150 lb. ASA |

EC 296166

TABLE 5.5-3

PRESSURIZER PARAMETERS

| | |
|---|---|
| Design Pressure, psig | 2485 |
| Design Temperature, F | 700 |
| Normal Operating Pressure, psig | 2235 |
| Normal Operating Temperature, F | 653 |
| Internal Free Volume, $ft.^3$ | 1500 |
| Normal Operating Water Volume, $ft.^3$ | 600-800 |
| Normal Steam Volume, Full Power, $ft.^3$ | 700-900 |
| Minimum Required Heater Capacity, kw | 1375** |
| Spray Flow, Maximum, gpm | 375 |
| Spray Flow, Continuous, gpm | 1.5 |
| Nozzles | |
| Surge Line (1 ea.) nominal, in. | 12, schedule 160 |
| Safety Valves (3), ID, in. | 3, flanged |
| Relief Valve (1), ID, in. | 4, schedule 160 |
| Spray (1) nominal, in. | 4, schedule 160 |
| Heater Sleeves/Heaters (120) | |
| Heater Sleeve OD, in. | 1.157 – 1.155 |
| Heater Sleeve ID, in. | 0.915 – 0.895 |
| Heaters OD, in. | 0.865 – 0.880 |
| Instrument, Level (4) nominal, in. | 1, schedule 160 |
| Temperature (2) nominal | 1, schedule 160 |
| Pressure (2) nominal, in. | 1, schedule 160 |
| Material | |
| Vessel | SA 508, Gr 3, Class 2 |
| Cladding (Shell and Upper Head) | Stainless Steel |
| Cladding (Lower Head) | Type 308/309 |
| Dimensions | |
| Overall Length, in. | 443.38* |
| Outside Diameter, in. | 106.56 |
| Inside Diameter, in. | 96.56 |
| Cladding Thickness, in. (minimum) | 0.2 |
| Dry Weight, Including Heaters, lb. | 201,196 |
| Flooded Weight, Including Heaters, lb. | 294,196 |

* Includes a 2" extension on the spray nozzles that will be partially or totally removed prior to installation.

** A total of 125 kw can be removed from service, as described below:
- No more than 2 proportional pressurizer heaters (25 kw), and;
- No more than 8 backup pressurizer heaters (100 kw), with a maximum of 2 heaters in any one backup heater bank.

TABLE 5.5-4

PRESSURIZER SAFETY VALVE PARAMETERS

| | |
|---|---|
| Tag Nos. | V1200, V1201, V1202 |
| Design Pressure, psig | 2485 |
| Design Temperature, °F | 700 |
| Fluid | Saturated Steam, 0.1% (wt) Boric Acid |
| Set Pressure, psia | 2500(+3%, -2.5%) |
| Capacity, lb./hr. at set pressure, each | 200,000 |
| Type | Spring loaded-balanced bellows. Enclosed bonnet. |
| Accumulation, % | 3 |
| Backpressure Compensation (25 psig) | Yes |
| Blowdown | 10 EC 295897 |
| Body | ASME SA 182 GR F316 or 304 |
| Bonnet | A 216 WCB |
| Code (original) | ASME Code for Pumps and Valves for Nuclear Power Class I, November 1968 Draft. |

TABLE 5.5-5

PRESSURIZER POWER-OPERATED RELIEF VALVE PARAMETERS

| | |
|---|---|
| Tag Numbers | V1404, V1402 |
| Design Pressure, psig | 2485 |
| Design Temperature, °F | 675 |
| Fluid | Saturated Steam,<br>0.1% (wt) Boric Acid |
| Capacity, lb./hr. | 153,000 |
| Type | Solenoid Operated<br>Voltage 125 vdc |
| Size | 2 1/2" - 2500 lb. by<br>4" – 300 lb. |
| Set Pressure, psig | 2385 |
| Body Material | ASTM-A-182 F-316 |
| Nozzle Material | ASTM-A-182 F-316<br>(Stellited) |
| Disc | Inconel 718 |
| Code | ASME Code for Pumps<br>and Valves for Nuclear<br>Power Class I, Nov.<br>1968 Draft |

TABLE 5.5 - 6

PRESSURIZER RELIEF MOTOR-OPERATED STOP VALVE PARAMETERS

| | |
|---|---|
| Tag Numbers | V1403, V1405 |
| Design Temperature, °F | 675 |
| Design Pressure, psig | 2485 |
| Actuator | Electric Motor |
| Failure Position | As Is |
| Material | ASTM-A-182 F-316 |
| Pump and Valve Code | Class I |
| Size and Schedule, in. | 2 ½ - 1500 lb. |
| Weld End | Butt Weld Sch. 160 |

TABLE 5.5-7

PNEUMATIC OPERATED PRESSURIZER SPRAY VALVE PARAMETERS

DESIGN VALUES

| | |
|---|---|
| Tag Numbers | PCV-1100E, PCV-1100F |
| Design Temperature, °F | 650 |
| Design Pressure, psig | 2485 |
| Flow, gpm | 375 |
| Pressure Drop, psi | 8.5 - 40 |
| Failure Position | Closed |
| Material | ASTM-A-351 CF8M |
| Pump and Valve Code | Class I |

TABLE 5.5-8

QUENCH TANK PARAMETERS

| | |
|---|---|
| Design Pressure, psig | 100 |
| Design Temperature, F | 350 |
| Normal Operating Pressure, psig | greater than 0 |
| Normal Operating Temperature, F | 120 |
| Internal Volume, $ft^3$ | 209 |
| Normal Water Volume, $ft^3$ | 127 |
| Normal Gas Volume, $ft^3$ | 82 |
| Blanket Gas | Nitrogen |
| Nozzles | |
| Pressurizer discharge (1) nominal, in. | 10 Sch. 40 |
| Demineralized water (1) in. | 2 3,000 lb. SW Coupling |
| Rupture Disc (1) in. | 18 Flanged |
| Drain (1) in. | 2 3,000 lb SW Coupling |
| Temp. Instrument (1) in. | 1 3,000 lb SW Coupling |
| Level Instrument (2) in. | 1 3,000 lb SW Coupling |
| Vent (1) in. | 1 ½ 3,000 lb SW Coupling |
| Vessel Material | ASTM-A-240 TP 304 |
| Dimensions | |
| Overall Length, in. | 145 ½ |
| Outside Diameter, in. | 60 |
| Dry Weight, lb | 4600 |
| Flooded Weight | 17,600 |

# TABLE 5.5-9

## REACTOR COOLANT PUMP PARAMETERS

## DESIGN VALUES

| | |
|---|---|
| Number | 4 |
| Type | Vertical, Limited Leakage, Centrifugal |
| Shaft Seals | Mechanical (4) |
| Stationary Face | Composite Carbon NMCC CNFJ |
| Rotating Face Ring | Tungsten Carbide, Kennametal KZ-801 or silicon carbide |
| Design Pressure, psig | 2485 |
| Design Temperature, F | 650 |
| Normal Operating Pressure, psig | 2235 |
| Normal Operating Temperature, F | 548 |
| Design Flow, gpm | 92,500 |
| Total Dynamic Head, ft. | 310 |
| Maximum Flow - (one-pump operation), gpm | 120,000 |
| Dry Weight, lb. w/o Motor | 75,000 |
| Flooded Weight, lb. w/o Motor | 82,000 |
| Reactor Coolant Volume, $ft.^3$ | 112 |
| Material | |
| Shaft | ASTM A-182 Type F-304 |
| Casing | ASTM A-351 Gr CF8M |
| Casing Wear Ring | ASTM A-351 Gr CF8 |
| Hydrostatic Bearing | |
| Bearing | ASTM A-351 Gr CF8 |
| Journal | ASTM A-351 Gr CF8 |
| Flywheel | ASTM A-516 Gr 65, or A543 CL1 Type B |
| Motor | |
| Voltage, volts | 6600 |
| Frequency, hz/phase | 60/3 |
| Horsepower/Speed, Hot, hp/rpm | 4300/900 |
| Horsepower/Speed, Cold, hp/rpm | 5700/900 |
| Service Factor | 1.15 |
| Weight (approx.) | 99,000 |

## REACTOR COOLANT PUMP PARAMETERS

Instrumentation

| | |
|---|---|
| Seal Temperature Detectors | 1 |
| Pump Casing Pressure Taps | 2 |
| Seal Pressure Detectors | 3 |
| Controlled Bleedoff Flow Detectors | 1 |
| Controlled Bleedoff Temperature Detectors | 1 |
| Motor Oil Level Detectors | 2 |
| Motor Bearing Temperature Detectors | 4 |
| Motor Stator Temperature Detectors | 6 |
| Vibration Detector (Vibration Switch) | 1 |
| Vibration Monitors (Shaft Displacement and Phase Angle) | 3 |
| Oil Lift Pressure Switches | 4 |
| Oil Lift Pressure Gauge | 1 |

Total Seal Assembly Leakage (Nominal Values)

| | |
|---|---|
| Three Pressure Seals Operating, gpm | 1.01 |
| Two Pressure Seals Operating, gpm | 1.24 |
| One Pressure Seal Operating, gpm | 1.75 |

TABLE 5.5-10

REACTOR COOLANT PIPING PARAMETERS

| | |
|---|---|
| Number of loops | 2 |
| Flow per loop, lb/hr | 69.7 x $10^6$* |
| Pipe Size | |
| Reactor outlet, ID/wall, in. | 42/ 3¾ min. w/o clad |
| Reactor inlet, ID/wall, in. | 30/ 2½ min. w/o clad |
| Surge line, nominal, in. | 12 SCH 160 |
| Design Pressure, psig | 2485 |
| Design Temperature, F | 650 |
| Velocity, Hot leg, ft/sec | 42 |
| Velocity, Cold leg, ft/sec | 37 |

* For Cycle 15 with replacement steam generators, the flow per loop is 77.88 x $10^6$ lb/hr.

**REFER TO DRAWING**

**8770-13348**

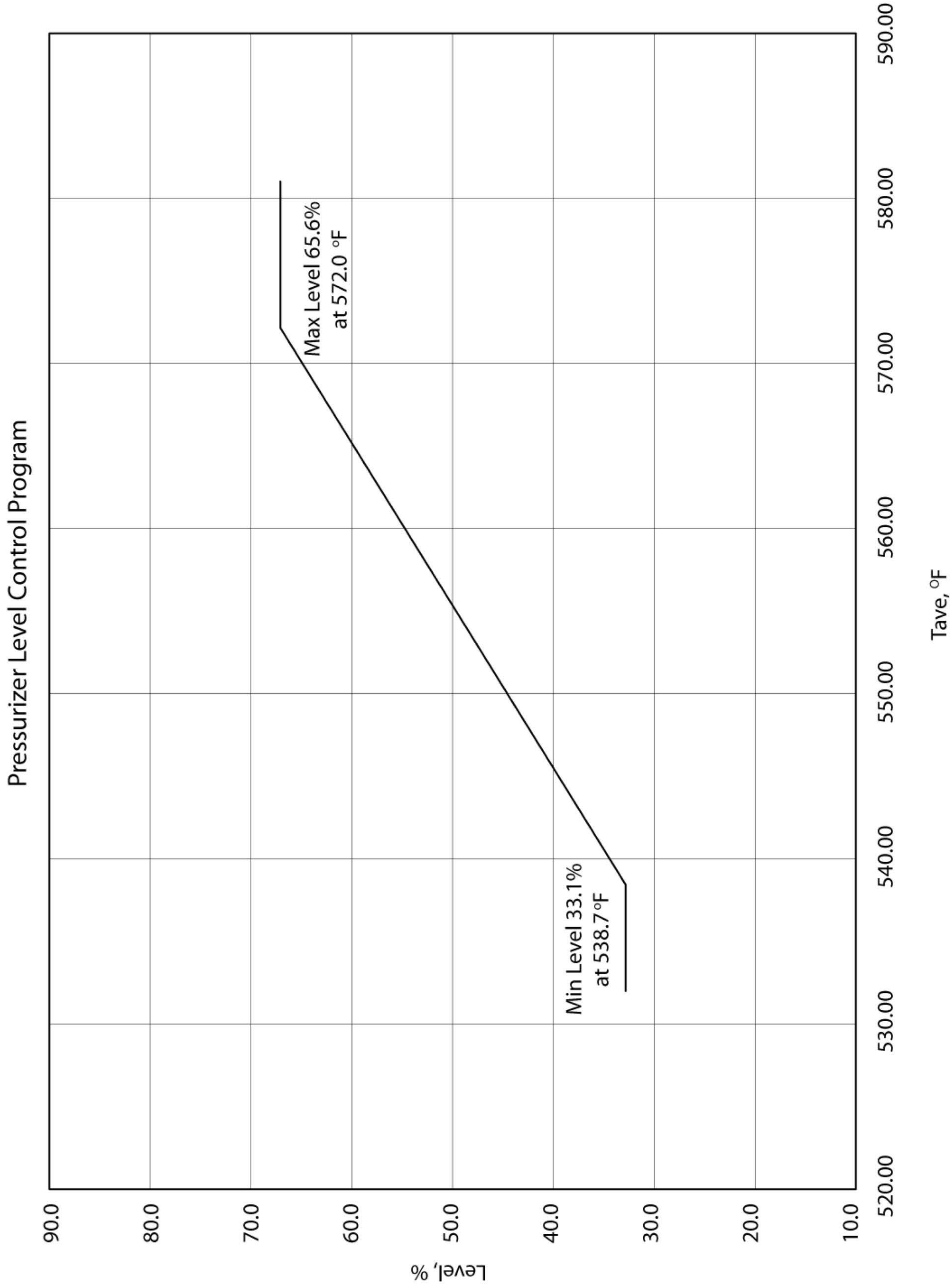
| Florida Power & Light Company<br>St. Lucie Plant Unit 1 |
| --- |
| General Arrangement<br>Figure 5.5-1 |

REFER TO DRAWING

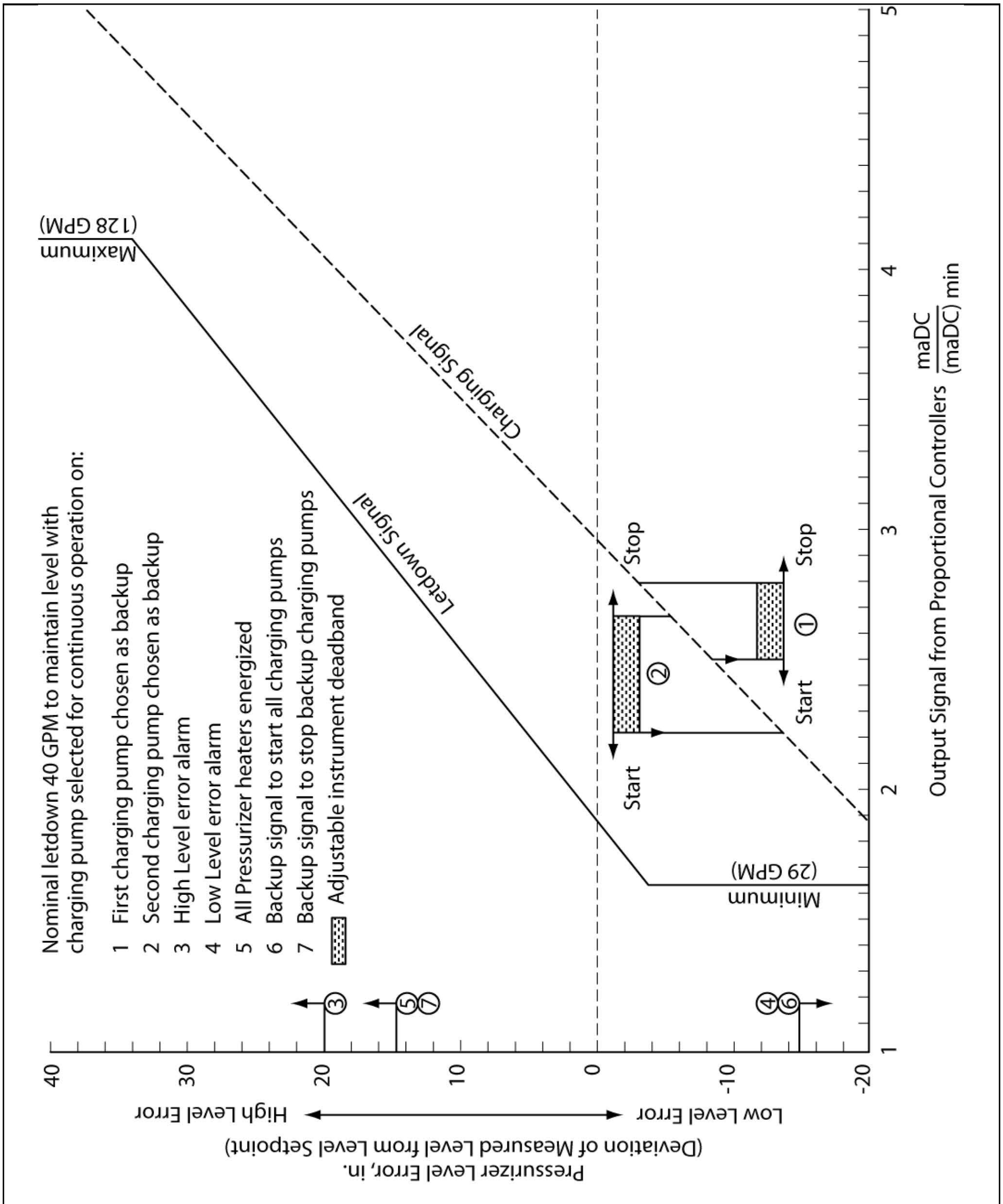
8770-15307

Florida Power & Light Company
St. Lucie Plant Unit 1

Pressurizer
Figure 5.5-2




| | | |
|---|---|---|
| FLORIDA<br>POWER & LIGHT CO.<br>St. Lucie Plant | CYCLE 1<br>Liquid Volume Maintained by<br>Pressurizer Level Program | FIGURE 5.5-3 |




| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO.<br>St. Lucie Plant | Pressurizer Level Control Program | FIGURE 5.5-4 |

Refer to drawing
8770-898

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER QUENCH TANK-ARRANGEMENT

FIGURE 5.5-5

**REFER TO DRAWING**
**RCP 1A1, 1A2, 1B1, 1B2**
**8770-17242**

| |
|---|
| Florida Power & Light Company<br>St. Lucie Plant Unit 1 |
| Sectional Assy<br>Reactor Primary Coolant Pump<br>Figure 5.5-6 |

**REFER TO DRAWING**

**8770-G-078, Sheets 111A, B, C & D**

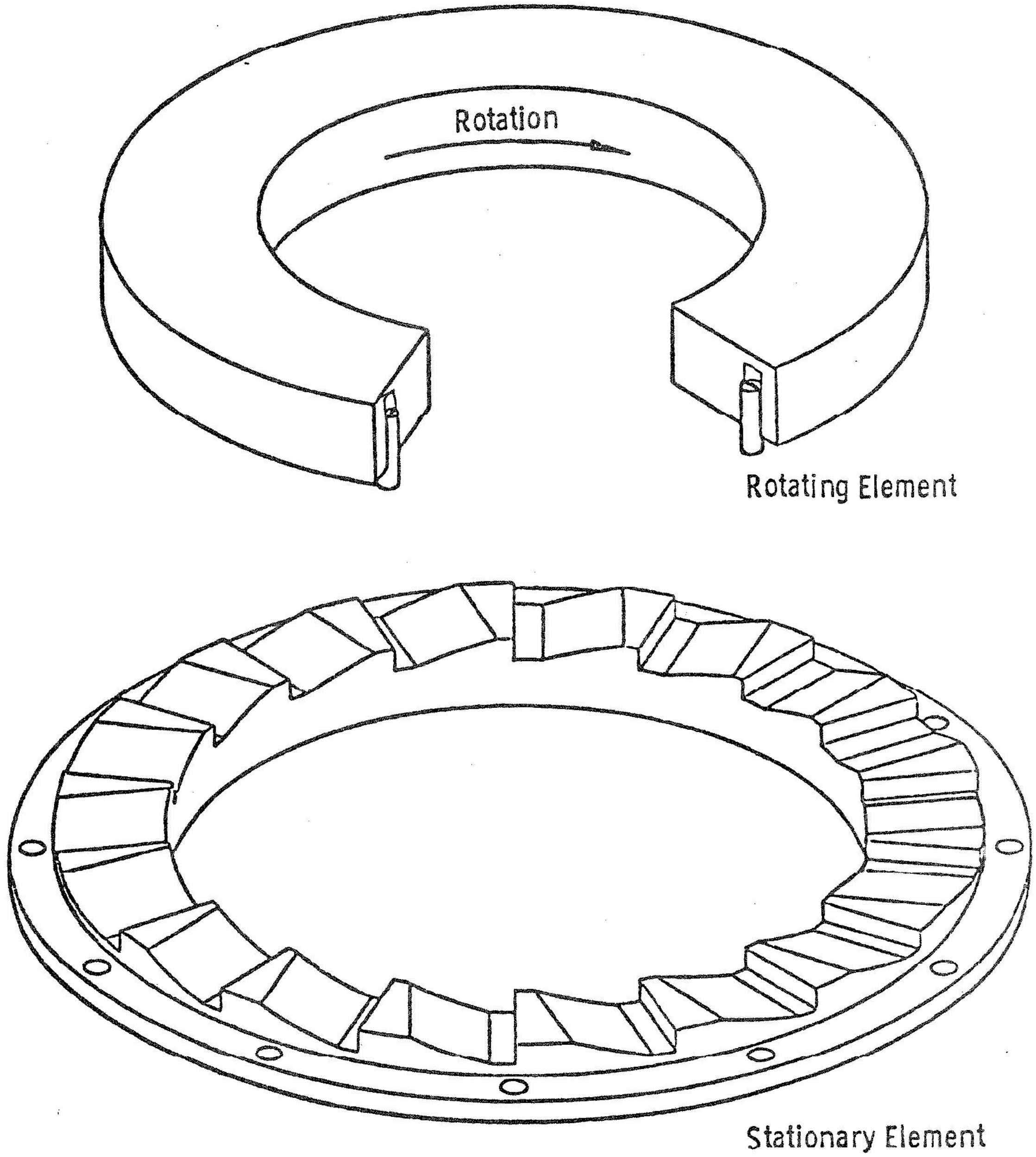
FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

FLOW DIAGRAM
REACTOR COOLANT PUMP

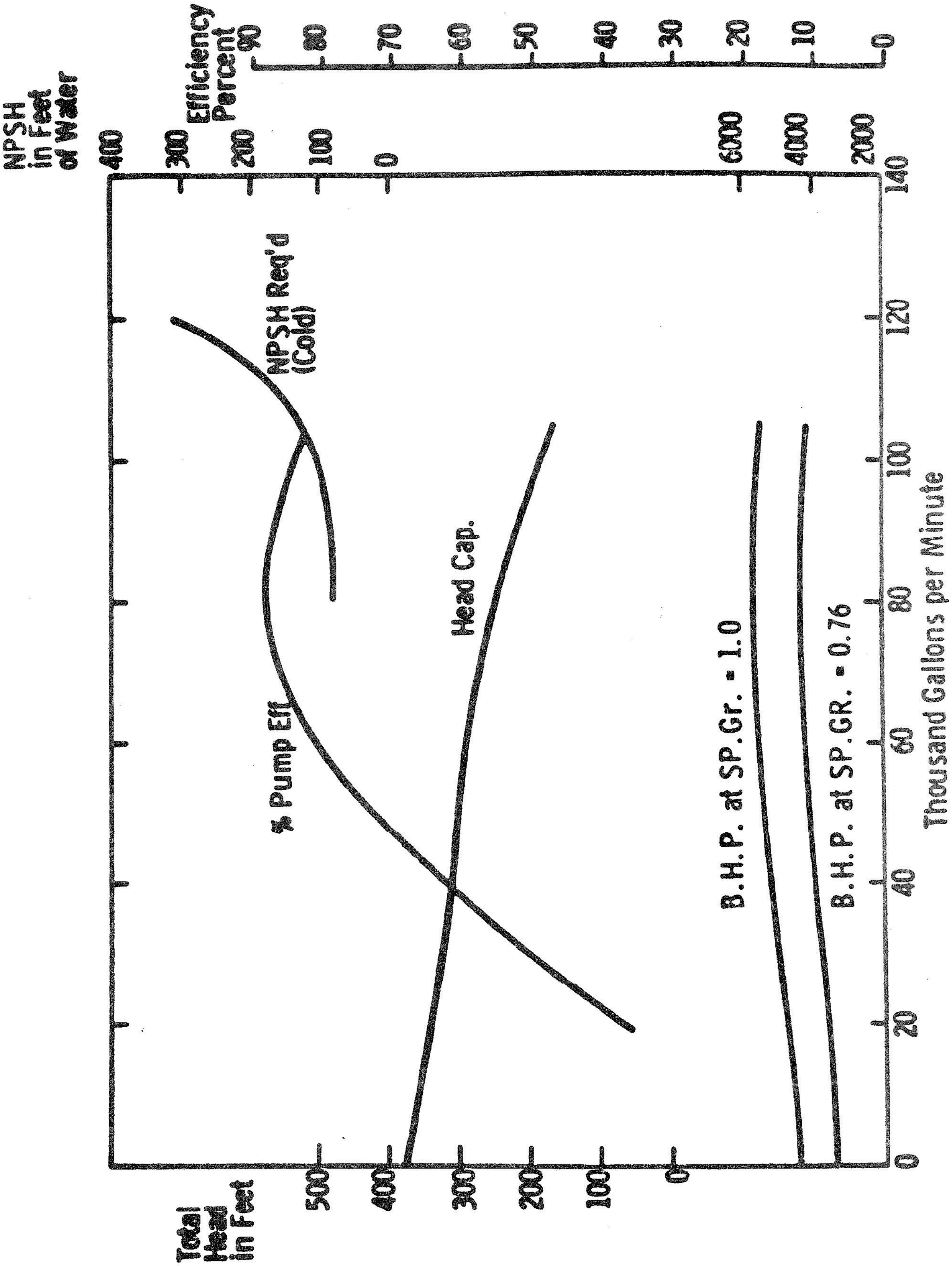
**FIGURE 5.5-7**

**REFER TO DRAWING**
**RCP 1B1, 1A1, 1A2, 1B2**
**2998-22548, 2998-22550**

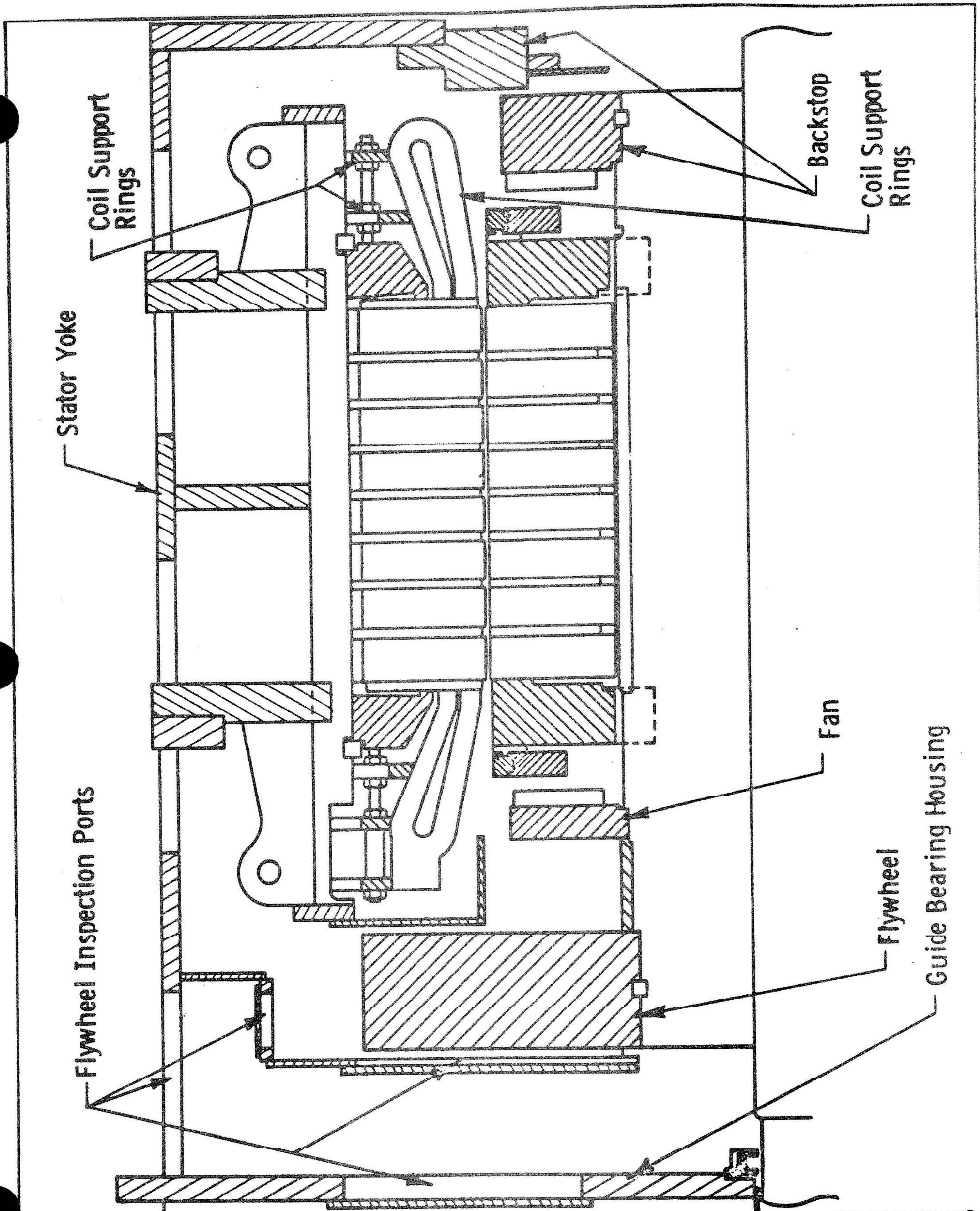
| Florida Power & Light Company<br>St. Lucie Plant Unit 1 |
| --- |
| Reactor Coolant Pump Shaft Seal<br>Arrangement, N-9000 Seal<br>Figure 5.5-8 |



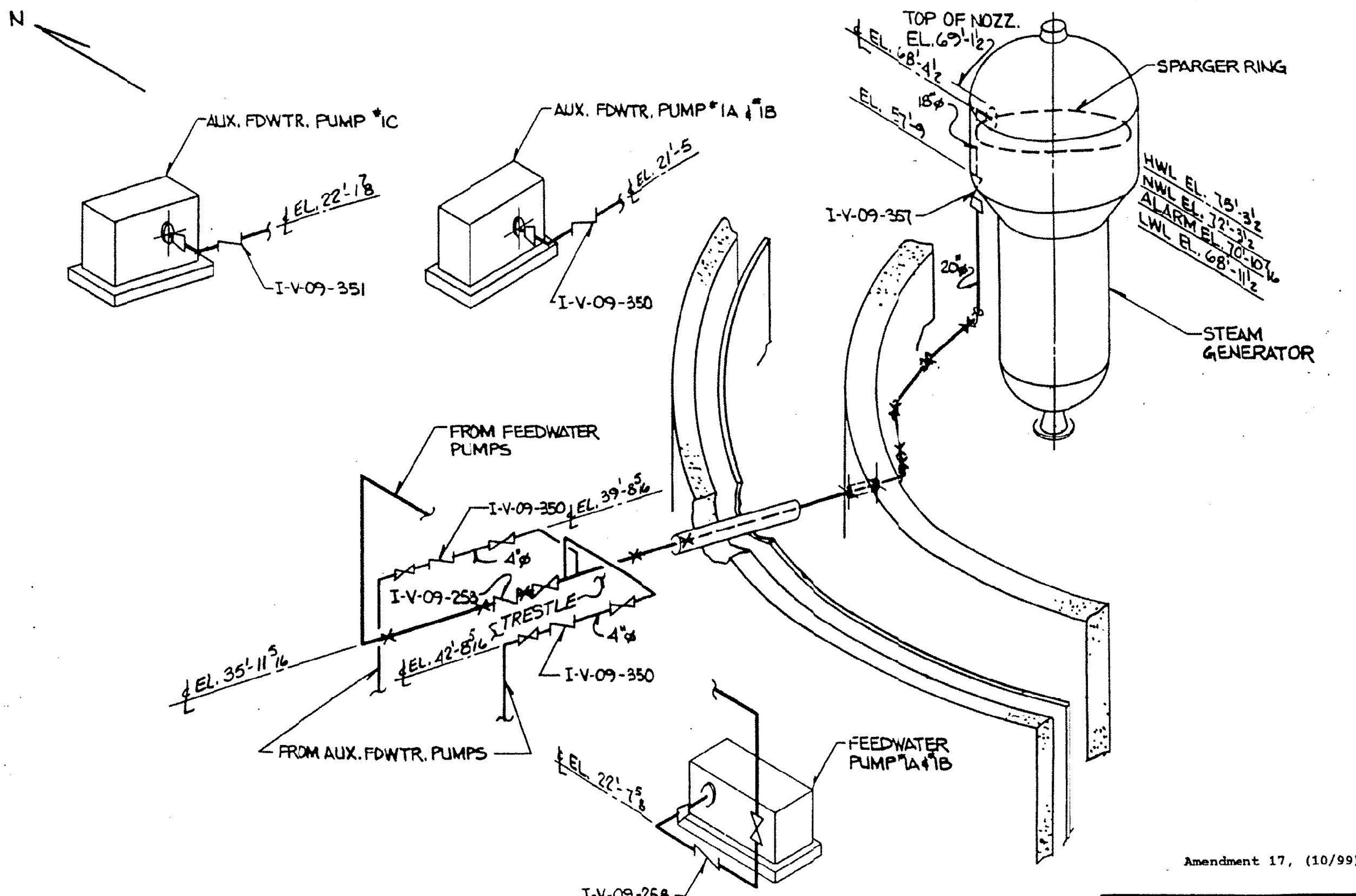

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | ANTI-ROTATIONAL DEVICE | Figure 5.5-9 |




| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Reactor Coolant Pump Performance | Figure 5.5-10 |
|---|---|---|




| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Motor-Flywheel Assembly | Figure 5.5-11 |



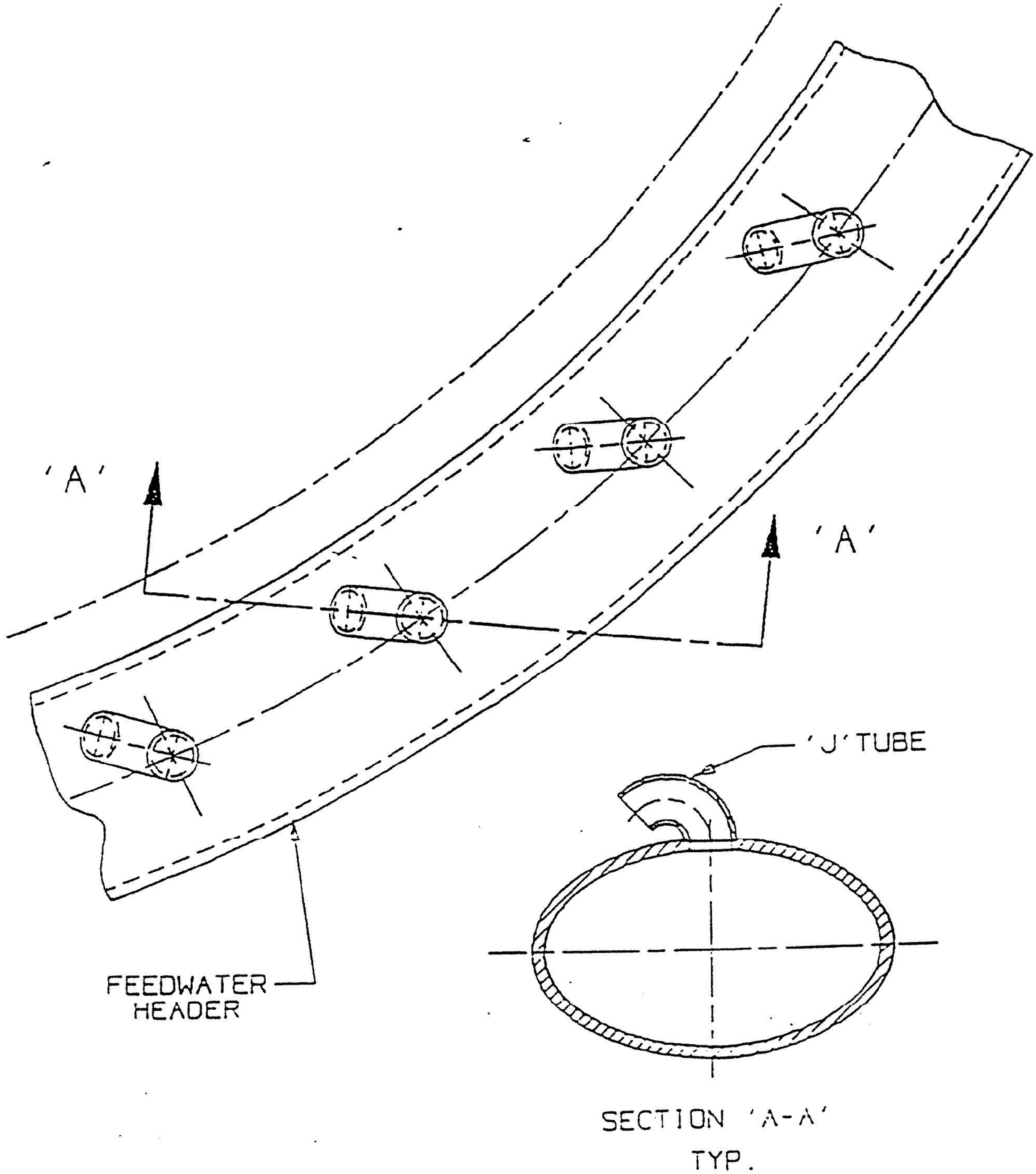

Amendment 17, (10/99)

HISTORICAL

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR
FEEDWATER SYSTEM

FIGURE 5.5-12




Amendment No. 16, (1/98)

| |
|---|
| FLORIDA POWER & LIGHT COMPANY<br>**ST. LUCIE PLANT UNIT 1** |
| STEAM GENERATOR FEED RING |
| **FIGURE 5.5-13** |

**REFER TO DRAWING**

**8770-G-091, Sheet 1**

**FLORIDA POWER & LIGHT COMPANY**
**ST. LUCIE PLANT UNIT 1**

FLOW DIAGRAM

**MISCELLANEOUS SYSTEMS**

FIGURE 5.5-14

## 5.6 INSTRUMENTATION APPLICATION

The measurement channels necessary for operational control and protection of the reactor coolant system are listed in Table 5.6-1 and shown in Figure 5.1-3. Further description of the instrument channels is given in Chapter 7.

Four independent measurement channels are provided for each parameter which initiates protective system action. Two independent signals are required to initiate protective action, thereby preventing spurious actions resulting from the failure of one measurement channel. This arrangement results in a high degree of protective measurement channel reliability in terms of initiating action when required and avoiding unnecessary action from spurious signals.

Two independent measurement channels are provided for parameters which are critical to operational control. These control channels are separate from the protective measurement channels. To avoid conflicts, control action is derived from only one channel at any time, while the second channel serves as a backup. This allows continued operation of the plant if one channel fails and permits maintenance on the failed channel during operation. This arrangement results in increased plant availability.

### 5.6.1 TEMPERATURE

The purpose of the RCS hot and cold leg temperature indication is to determine RCS fluid temperature and to assure core heat is being removed by assuring $\Delta T$ between hot and cold leg temperatures. For temperatures where the RCS temperature is below 350°F, the Shutdown Cooling (SDC) Systems would be in operation, taking suction from the hot legs (normal) or the containment sump (post LOCA) and discharging into the RCS at the outlet of the Reactor Coolant pumps. Note: SDC system design temperature is 350ºF; however, normal practice is to limit system operation to RCS temperature less than or equal to 325ºF (see Section 9.3.5).

In this instance other instrumentation is available to determine RCS temperatures:

a) Core Exit Thermocouples (CETS) for hot leg temperatures (range 32°F to 2300°F)

b) Shutdown cooling temperature element (located on the LPSI header) which provides control room indication (range 0°F to 400°F).

#### 5.6.1.1 Hot Leg Temperature

Each of the two hot legs contains five narrow range RTD channels to measure coolant temperature leaving the reactor vessel. Four of these channels are used as hot leg temperature signals to the reactor protective system. The fifth hot leg temperature measurement channel provides a signal to the average temperature computer which is a part of the reactor regulating system. The average temperature for each loop is recorded on a two-pen recorder in the control room. The second pen on each recorder is the average temperature reference signal received from the reactor regulating system. There is a recorder for each loop. The reactor regulating system adjusts control rod position until the measured average temperature matches the programmed average temperature for the operating power level*.

* Refer to note on page 7.7-1

A high temperature alarm is provided on this channel to alert the operator to a high temperature condition. The temperature from this measurement channel is indicated in the control room in addition to being recorded. The other hot leg temperature channels are also displayed in the control room.

5.6.1.2 Cold Leg Temperature

Each of the four cold legs contains three temperature measurement channels. The cold leg RTDs are located downstream of the reactor coolant pumps. Two channels from each cold leg (four per heat transfer loop) are used to furnish a cold leg coolant temperature signal to the reactor protective system. All eight of these cold leg temperatures are indicated in the control room.

The remaining cold leg temperature measurement channels, one on each cold leg, are routed to a channel selector switch (One per heat transfer loop). This selector switch enables either cold leg temperature to be recorded on a wide range temperature recorder in the control room. The remaining channel of each loop provides a signal to the average temperature calculator in the reactor regulating system and to the automatic CEA withdrawal prohibit subsystem of the control element drive system.

For other reactor coolant system temperature measurement channels refer to Table 5.6-1.

## 5.6.2 PRESSURE

### 5.6.2.1 Pressurizer Pressure

Four independent narrow pressure channels are provided for initiation of protective system action. The pressure transmitters are connected to the upper portion of the pressurizer via the upper level measurements nozzles and measure pressurizer vapor pressure. All four channels are indicated in the control room and actuate separate high, low, or low -low pressure alarms in the control room.

The protection actions these pressure signals initiate are:

a) reactor trip on high primary system pressure. The reactor trip signals are also used to open the power operated relief valves at 2385 psig;

b) safety injection system actuation on low-low primary system pressure;

c) reactor trip on low reactor coolant system pressure. The set point is a function of the coolant temperatures in the hot and cold legs. The variable set point has high and low limits alarmed in the control room and is not allowed to decrease below 1887 psia.

Two independent pressure channels provide narrow range pressure signals for controlling the pressurizer heaters and spray valves. The output of one of these channels is manually selected to perform the control function. During normal operation, a small group of heaters are proportionally controlled to offset heat losses. If the pressure falls below a low pressure set point, all of the heaters are energized. If the pressure increases above a high-pressure set point, the spray valves are proportionally opened to increase the spray flow rate as pressure rises. These two channels are also used to provide pressurizer pressure signals to the reactor regulating system. The two channels are continuously recorded in the control room and are provided with high and low pressure alarms. Two restricted range pressure measurement channels provide a control room indication of reactor coolant system pressure during plant startup and shutdown in the control room. They also provide pressure signals to the shutdown cooling suction isolation valves to prevent them from opening above a selected set point.

For other reactor coolant system pressure measurement channels refer to Table 5.6-1.

## 5.6.3 LEVEL

### 5.6.3.1 Pressurizer Level

Two pressurizer level channels are used to provide two independent level signals for control of the pressurizer liquid level. These signals are used to deenergize the pressurizer heaters on low-low pressurizer level to prevent heater burnout, provide input to one pen in each of two 2-pen recorders in the control room, and actuate high and low pressurizer level alarms in the control room. The second pen on each level recorder records the programmed pressurizer level computed by the reactor regulating system as a function of the average reactor coolant temperature. The level transmitters are compensated for the steam and water densities existing in the pressurizer during normal operation.

The liquid level in the pressurizer is programmed to vary as a function of average reactor coolant temperature. This level setpoint is computed by the reactor regulating system and furnished to controls associated with these measurement channels. One of the two measurement channels is manually selected to furnish an actual liquid level signal to the controls. If these two signals differ, the level control adjusts the chemical and volume control system charging or letdown flow rates to make the difference zero. Each of these level channels is indicated and alarmed (high and low) in the control room.

One wide range pressurizer level channel is provided for control room indication of pressurizer level during plant startup and shutdown.

For other reactor coolant system level measurement channels refer to Table 5.6-1.

## 5.6.4 REACTOR COOLANT LOOP FLOW

Four independent differential pressure measurement channels are provided in each heat transfer loop to measure the pressure drop across the steam generators. Four pressure taps are located in each hot leg piping section just before the elbow entering the steam generator and four pressure nozzles are located in the steam generator outlet plenum. Four differential pressure transmitters are connected between the four hot leg nozzles and the steam generator nozzles, resulting in four steam generator differential pressures.

The output of the transmitters are sent to four analog summing devices in the low total flow trip logic. Each summer receives two differential pressure signals with the summation of these signals corresponding to the total core flow at all times.

The summers provide four independent total flow signals. The four signals are indicated separately in the control room and activate separate low flow alarms. In the reactor protective system, they are compared with the low flow reactor trip setpoint. If two channels indicate a flow which is less than the flow setpoint, the reactor is tripped.

### 5.6.5 SUBCOOLED MARGIN MONITORING SYSTEM

The subcooled margin monitoring system is described in Section 7.5.4.2.

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TABLE 5.6-1

REACTOR COOLANT SYSTEM INSTRUMENTATION

| System Parameter & Location | Indication: Local | Indication: Contr Room | Alarm[1]: High | Alarm[1]: Low | Rec[1] | Control Function | Inst. Range[4] | Normal[3] Operating | Inst. Accuracy[4] |
|---|---|---|---|---|---|---|---|---|---|
| Pressurizer Temperature | | * | | | | | | 653F | |
| Spray Line Temperature | | * | | * | | | | 520 - 548.5F | |
| Surge Line Temperature | | * | | * | | | | 653F | |
| Relief Line Temperature | | * | * | | | | | 120 - 170F | |
| Loop 1A Hot Leg Temp. | | * | * | | * | RRS, TM/LP | | 594F | |
| Loop 1A1 Cold Leg Temp. | | * | * | | * | TM/LP, CEDS, RRS | | 532 - 550F<br>548.5F | |
| Loop 1A2 Cold Leg Temp. | | * | * | | * | TM/LP, CEDS, RRS | | 532 - 550F<br>548.5F | |
| Loop 1A Temp. | | * | | | * | TAVG/TREF | | 574F | |
| Loop 1B Hot Leg Temp. | | * | * | | * | RRS, TM/LP | | 594F | |

TABLE 5.6-1 (Cont'd)

| System Parameter & Location | Indication Local | Indication Contr Room | Alarm[1] High | Alarm[1] Low | Rec[1] | Control Function | Inst. Range[4] | Normal[3] Operating | Inst. Accuracy[4] |
|---|---|---|---|---|---|---|---|---|---|
| Loop 1B1 Cold Leg Temp. | | * | | | * | TM/LP, CEDS, RRS | | 532 - 550F<br>548.5F | |
| Loop 1B2 Cold Leg Temp. | | * | * | | * | TM/LP, CEDS, RRS | | 532 - 550F<br>548.5F | |
| Loop 1B Temp. | | * | | | * | TAVG/TREF | | 574F | |
| Quench Tank Temp. | | * | * | | | | | 85 - 104F | |
| Pressurizer Pressure | | * | * | * | * | Proportional Heaters, Backup Heaters, Spray Valves, Protective Functions (Safety Related) | | 2250 PSIA | |
| | | * | | | | Shutdown Cooling & Safety Injection Tank Interlocks | | | |
| Reactor Vessel Leakage | * | | * | | | | | 0 PSIA | |
| Quench Tank Pressure | | * | * | | | | | 16-18 PSIA | |

TABLE 5.6-1 (Cont'd)

| System Parameter & Location | Indication Local | Indication Contr Room | Alarm[1] High | Alarm[1] Low | Rec[1] | Control Function | Inst. Range[4] | Normal[3] Operating | Inst. Accuracy[4] |
|---|---|---|---|---|---|---|---|---|---|
| Pressurizer Level | | * | * | * | * | Proportional Heaters, Backup Heaters, Charging Pumps, Letdown Valves. | | 56.2% | |
| Quench Tank Level | | * | * | * | | | | 60% | |
| Reactor Coolant Flow | | * | | | | Protective Functions (Safety Related) | | 25 psid | |
| Pressurizer Relief and Safety Valve Position Indication[2] | | * | | | | | | | |

1 All alarms and recorders are in the control room unless otherwise indicated.
2 This was installed as a NUREG-0737 requirement. Refer to Section 7.5 for description.
3 Cycle 15 with Replacement Steam Generators - 0% Plugging
4 Instrument ranges are selected in accordance with standard engineering practices. Instrument accuracies are selected such that existing instrument loop performance and safety analysis assumptions remain valid. Where applicable, instrument accuracies are also evaluated for their impact on setpoints in accordance with the FPL Setpoint Methodology.

TABLE 5.6-2

SATURATION MARGIN MONITORING SYSTEM SENSORS

| Measured Quantity | | Sensor Tag Numbers |
|---|---|---|
| Reactor Coolant System Loop No.1 | | |
| 1) | RCS Cold Leg | TT-1112 CA |
| 2) | RCS Cold Leg | TT-1112 CB |
| 3) | RCS Hot Leg | TT-1112 HA |
| 4) | RCS Hot Leg | TT-1112 HB |
| Reactor Coolant System Loop No. 2 | | |
| 1) | RCS Cold leg | TT-1122 CA |
| 2) | RCS Cold Leg | TT-1122 CB |
| 3) | RCS Hot leg | TT-1122 HA |
| 4) | RCS Hot Leg | TT-1122 HB |
| Pressurizer Pressure | | |
| 1) | Wide Range | PT-1107 |
| 2) | Wide Range | PT-1108 |

## 5.7 REACTOR COOLANT GAS VENT SYSTEM (NUREG-0737, ITEM II.B.1, "CLARIFICATION OF TMI ACTION PLAN")

### 5.7.1 DESIGN BASES

#### 5.7.1.1 Functional Requirements

The Reactor Coolant Gas Vent System (RCGVS) is designed to perform the following functions:

a) The primary function of the system is to allow for remote venting of the Reactor Coolant System (RCS) via the reactor vessel head vent or pressurizer steam space vent during post-accident situations when large quantities of non-condensable gases may collect in these high points.

b) As a secondary function, the system may be used in normal RCS venting procedures required for a plant outage.

#### 5.7.1.2 Design Criteria

a) Flow Rate

The basic purpose of the vent system is to remove non-condensable gases (primarily hydrogen) from the RCS in a timely manner.

1) The system is designed to vent non-condensable gas from the RCS in a reasonable period of time over a wide range of reactor coolant temperature and pressure conditions. The system is designed to vent one-half of the RCS volume in one hour with the vented volume expressed in standard cubic feet of gas, at RCS pressures greater than 50 psia.

2) Flow through the vent system must be limited to avoid excessive mass loss from the Reactor Coolant System. By utilizing flow restricting orifices, the RCGVS is designed to:

(a) Limit the coolant liquid loss through the vent to the makeup capacity of one charging pump. This limits the mass loss to below the definition of a LOCA in 10 CFR 50, Appendix A.

(b) Limit the vent mass rate such that venting does not result in heat or mass loss from the RCS which would result in uncontrollable pressurizer pressure or level changes under emergency conditions. With 72 of 120 heaters available, the heat loss is within the heater capacity. EC291723

b) Controls

The vent system controls are designed to allow venting under accident conditions and minimize the potential for inadvertent operation.

1) The system permits remote (control room) venting from the reactor vessel head or the pressurizer.

2) The vent system is operable following all design basis events except those requiring evacuation of the control room.

3) Positive open/close control room position indication is provided for all solenoid operated valves. This indication is provided by reed switches which directly sense the valve stem position. The switches are environmentally qualified to the same requirements as the valves.

4) During normal plant operation, power is removed from the solenoid valves to minimize the probability of inadvertent operation of the RCGVS. Administrative procedures insure reconnection of power in the event that operation of the RCGVS is required.

5) The RCGVS is designed for a single active failure with active components powered from their respective redundant emergency power sources. Parallel vent paths with valves powered from alternate power sources are provided. The solenoid operated valves are powered from safety grade 125V dc power supplies. Power is removed from the fail closed valves, by utilizing key-locked control switches, to minimize the possibility of inadvertent operation during normal operation.

c) Piping and Arrangement

1) The vent path is safety grade and meets the same qualifications as the RCS. Redundance in the vent path is provided and essential piping and components are seismic Category 1, Safety Class 2.

2) The system is designed not to interfere with refueling maintenance actions. System piping is flanged where required to facilitate removal of components that might interfere with refueling operation.

3) Vent paths are provided to both the quench tank and containment atmosphere. The quench tank path allows for cooling of gases and condensing water vapor by releasing the vented gases below the water level in the tank. The containment vent path terminates in the area where good air mixing and maximum cooling properties exist.

4) The vent system materials are designed to be compatible with superheated steam, steam/water mixtures, water, fission gases, helium, nitrogen, and hydrogen as high as 2500 psia and 700F.

## 5.7.2 SYSTEM DESCRIPTION

### 5.7.2.1 Summary

The system is designed to permit the operator to vent the reactor vessel head or pressurizer steam space from the control room under post-accident conditions, and is operable following all design basis events except those requiring evacuation of the control room. The vent path from either the pressurizer or reactor vessel head is single active failure proof with active components powered from emergency power sources. Parallel valves powered off alternate power sources are provided at both vent sources to assure a vent path exists in the event of a single failure of either a valve or the power source. The system provides a redundant vent path either to the containment directly or to the quench tank. The quench tank route allows removal of the gas from the RCS without the need to release the highly radioactive fluid into containment. Use of the quench tank provides a discharge location which can be used to store small quantities of gas without influencing containment hydrogen concentration levels. However, venting large quantities of gas to the quench tank will result in rupture of the quench tank rupture disc providing a second path to containment for vented gas.

Cooling of gas vented to the quench tank is provided by introducing the gas below the quench volume. The direct vent path is located to take advantage of mixing and cooling in the containment. The system is designed with a flow limiting orifice to limit flow such that the mass flow rate of reactor coolant system fluid out of the vent is less than the makeup capacity of a single coolant charging pump. This effectively limits the flow to less than the LOCA definition of 10 CFR 50, Appendix A. The vent rate limitation also assures that RCS pressure control is not compromised by venting operation. The system has the capability to vent large quantities of hydrogen gas from the RCS.

Although designed for accident conditions, the system may be used to aid in the pre or post-refueling venting of the Reactor Coolant System. Venting of the individual CEDMs and RCPs will still be necessary, however, pressurizer and reactor vessel venting can be accomplished with the system if desired. Vent flow can be directed to the quench tank or through a charcoal filter to the containment purge header for this operation to prevent inadvertent release of radioactive fluid to the containment.

As shown on Figure 5.1-3 non-condensable gases are removed from either the pressurizer or reactor vessel through the flow restricting orifice and one of the parallel isolation valves and delivered to the quench tank or containment via their isolation valves. Venting under accident conditions would be accomplished using only one source (reactor vessel or pressurizer) and one sink (quench tank or containment atmosphere) at a given time.

#### 5.7.2.1.1 Normal Operation

This system is not intended for use during normal power operation and administrative controls are provided to minimize the possibility of inadvertent operation.

During normal operation, leakage detection is maintained by use of the pressure instrumentation. A rise in pressure will indicate leakage past any of the system isolation valves. Small leakage rates can be determined by conducting RCS leak rate calculations. Larger leakage rates can be determined by directing leakage to the quench tank and monitoring tank level change or to the accumulator and monitoring sump instrumentation.

5.7.2.1.2 Accident Operation

Operation of the RCGVS during accident conditions will vary depending on the rate of gas generation. For low gas generation rates, gas from within the reactor vessel or pressurizer is vented to the quench tank. Reactor and/or pressurizer vent valves are lined up and the gas released to the quench tank. Monitoring of quench tank pressure is necessary during this mode of operation. From this point the gas could be discharged to the gaseous waste management system if it is available for use.

For high gas generation rates, gases may be vented to the containment atmosphere. Should this valve fail, vent to containment atmosphere can still be accomplished through the quench tank rupture disc.

When venting to either the quench tank or containment, the system operating procedures will require that the operator open the pressurizer or reactor vessel solenoid valve which is powered from the alternate emergency bus (i.e., two valves in series will be open, one powered from bus A, and the other from the bus B). This will allow termination of venting for the unlikely situation where one of the valves should electrically fail open.

The RCGVS will be operated as an on-off system to remove gas from the RCS. The volume of gas to be removed is determined by reactor vessel or pressurizer instrumentation and then the venting time is determined dependent upon this volume and system temperature and pressure.

5.7.2.2 Component Description

There are no major components in the RCGVS. The entire system consists of piping, valves, and pipe fittings. All piping and valves are constructed of austenitic stainless steels and are Nuclear Safety qualified according to the Class as indicated on Figure 5.1-3. Piping system supports and all valves are also seismically qualified. Power operated valves are solenoid operated type designed to fail close to minimize inadvertent operation. The solenoid valves, control circuitry and position indicator switches are Class 1E qualified to IEEE-382-1972 for inside containment, IEEE-344-1975 for seismic and IEEE-323-1974 for environmental qualification. Redundancy in valve arrangement and power supply is designed to meet the single failure criterion. Part of the piping system includes orifices at the pressurizer vent and reactor vessel head vent, both sized to meet the flow requirements of system design criteria.

### 5.7.3 SAFETY EVALUATION

#### 5.7.3.1 Performance Requirements, Capabilities, and Reliabilities

The ability to vent the RCS - either reactor vessel or pressurizer - under accident conditions is assured by providing redundant flow paths from each venting source, redundant discharge paths, and emergency power to all power operated valves. A single active failure of either a power operated valve or power supply will not prevent venting to containment (either directly or through the quench tank dependent upon failure mode) from either source.

#### 5.7.3.2 Pipe Break Analysis

Consistent with NRC requirements, the RCGVS is designed to limit mass loss to less than a LOCA as defined in 10 CFR 50, Appendix A and thus a separate analysis of inadvertent system operation or pipe breakage is not required to meet 10 CFR 50.46.

The pressure boundary of the normally pressurized portion of the head vent system is protected from the effects of postulated pipe breaks in the main loop cold leg piping, or branch lines to the cold legs, or non-RCPB piping. The pressure boundary of the normally unpressurized portion of the vent system is protected from the effects of postulated pipe breaks in non-RCPB lines for which venting would be required.

The flow function of the vent system is protected from the effects of failures for which venting would be required.

#### 5.7.3.3 Leakage Detection

Leakage past the system isolation valves into the normally unpressurized portion of the system is detected by pressure instrumentation.

#### 5.7.3.4 Natural Phenomena

RCGVS components are located in containment and, therefore, are not subjected to the natural phenomena described in Chapter 3 other than seismic. Piping has been analyzed and supported in accordance with St. Lucie Unit 1 seismic criteria. All valves have been analyzed and tested for operability during a seismic event by manufacturers.

5.7.3.5 Failure Modes and Effects Analysis

Table 5.7-1 shows a failure mode and effects analysis for the RCGVS. At least one failure is postulated for each safety-related component of the RCGVS. In each case the possible cause of such a failure is presented as well as the local effects, detection methods, and compensating provisions.

## 5.7.4 INSPECTION TESTING REQUIREMENTS

Each component was inspected and cleaned prior to installation into the RCGVS. The instrument was calibrated during pre-operational testing. The valves and controls were tested for operability following installation.

Components have been specified and purchased as seismic Category I and Nuclear Safety Class where required. Vendors have substantiated either through test, calculational and/or operational data that system components will remain operable under the design seismic loads. Vendors have tested and inspected all safety class equipment in accordance with applicable ASME and IEEE codes.

Implementation of a periodic operational testing and inspection program in accordance with ASME Section XI, Subsection IWV will insure system operability after installation.

## 5.7.5 INSTRUMENTATION REQUIREMENTS

The system is designed to be controlled remotely from the main control room. All power-operated valves powered from emergency power sources and alternate sources are used as necessary to meet single failure criteria. Position indication (open/shut) is provided for all remotely operated valves and displayed in the control room.

5.7.5.1 Pressure Instrumentation

Vent header pressure instrumentation is provided to monitor any valve leakage. Pressure indicator is located in the control room.

TABLE 5.7-1

FAILURE MODES EFFECTS ANALYSIS FOR THE REACTOR COOLANT GAS VENT SYSTEM

| No. | Name | Failure Mode | Cause | Symptoms and Local Effects Including Dependent Failures | Method of Detection | Inherent Compensating Provision | Remarks and Other Effects |
|---|---|---|---|---|---|---|---|
| 1. | Pressure Indicator PI-1117 | a. Spurious high press indication | Instrument drift | No impact on normal operation. Loss of ability to detect leakage into the vent system piping. | Valve position indication in the C.R. | None | |
| | | b. Spurious low press indication | Instrument drift | No impact on normal operation. Loss of ability to detect leakage into the vent system piping. | Valve position indication in the C.R. | None | |
| 2. | Quench Tank Isolation Valve V1445 | a. Fails Open | Mechanical binding, seat leakage | Inability to isolate quench tank from the reactor coolant gas vent. | Valve position indication in the C.R. | None | Redundant isolation valves to the reactor vessel and pressurizer preclude uncontrolled venting to the quench tank. |
| | | b. Fails Closed | Mechanical failure, loss of power | No impact on normal operation. Inability to vent pressurizer or reactor to quench tank. | Valve position indication in the C.R. | None | Venting to the containment is possible, if necessary. |
| 3. | Pressure Instrument Isolation Valve V1447 | a. Fails Open | Mechanical binding, seat leakage | None | Operator | Redundant valves | |
| | | b. Fails Closed | Mechanical failure | Loss of ability to detect seat leakage from the pressurizer and reactor isolation valves into the reactor coolant gas vent system piping. | Operator | None | Unlikely event since valve is normally open and has only a manual operator. |
| 4. | Containment Isolation Valve V1446 | a. Fails Open | Mechanical binding, seat leakage | Inability to isolate reactor coolant vent system from containment. | High containment press & humidity if venting is in progress. Valve position indication in the C.R. | None | Redundant isolation valves provided to preclude uncontrolled venting to RCS. |
| | | b. Fails Closed | Mechanical failure, loss of power to valve | No impact on normal operation. Inability to vent pressurizer or reactor to containment. | Valve position indication in the C.R. | None | Venting to the quench tank is possible, if necessary. |

TABLE 5.7-1 (Cont'd)

| No. | Name | Failure Mode | Cause | Symptoms and Local Effects Including Dependent Failures | Method of Detection | Inherent Compensating Provision | Remarks and Other Effects |
|---|---|---|---|---|---|---|---|
| 5. | Pressurizer Vent Isolation Valve V1443 or V1444 | a. Fails Open | Mechanical binding, seat leakage. | No impact on normal operation. Inability to vent the reactor vessel without also venting pressurizer. | Valve position indication in the C.R. PI-1117 high pressure indication. | None | Redundant isolation valves to containment V1443 & V1444 precludes uncontrolled venting of the pressurizer. |
| | | b. Fails Closed | Mechanical failure, loss of power. | Inability to vent the pressurizer. | Valve position in C.R. | Parallel redundant isolation valve. | Parallel isolation valve allows venting of the pressurizer. |
| 6. | Reactor Vessel Vent Isolation Valve V1441 or V1442 | a. Fails Open | Mechanical binding, seat leakage. | No impact on normal operation. Unable to vent pressurizer without also venting the reactor vessel. | Valve position indication in the C.R. PI-1117 high pressure indication. | None | Redundant isolation valves to containment V1446 & V1445 precludes uncontrolled venting of the reactor vessel. |
| | | b. Fails Closed | Mechanical failure, loss of power. | Inability to vent the reactor vessel. | Valve position in the C.R. | Parallel redundant isolation valve. | Parallel isolation valve allows venting of the reactor vessel. |
| 7. | Position Indicator for V1441 & V1442 | False indication of valve position | Electro-mechanical failure. | Loss of ability to detect valve position in reactor vessel vent line. | Pressure Gauge PI-1117 indication shows valve is opened. | None | |
| 8. | Position Indicator for V1443 & V1444 | False indication of valve position | Electro-mechanical failure. | Loss of ability to detect valve position in pressurizer vent line. | Pressure Gauge PI-1117 indication shows valve is opened. | None | |
| 9. | Position Indicator for V1445 | False indication of valve position | Electro-mechanical failure. | Loss of ability to detect valve position in quench tank vent line. | Quench tank temp & pressure verify valve position. Press gauge PI-1117. | None | |
| 10. | Position Indicator for V1446 | False indication of valve position | Electro-mechanical failure. | Loss of ability to detect valve position in containment vent. | Containment pressure/ humidity/radiation levels verify containment valve position. Press gauge PI-1117. | None | |
| 11. | Vent & Drain Valves V1452 & V1453 | a. Seat leakage | Contamination, mechanical damage | No impact on system operation. | None | Drain valves are provided with secondary boundaries, such as blind flanges. | |
| | | b. Fails Closed | Mechanical binding | No impact on normal operations. Inability to drain affected line section or test isolation valves per ASME XI. | Operator | None | |

| No. | Name | Failure Mode | Cause | Symptoms and Local Effects Including Dependent Failures | Method of Detection | Inherent Compensating Provision | Remarks and Other Effects |
|---|---|---|---|---|---|---|---|
| 12. | Leakage Detection Valve V1449 | a. Fails Open | Mechanical binding, seat leakage. | Inability to isolate leakage detection system from RCGVS. | Valve position indication in C.R. | None | Leakage detection system represents another path to containment, though not recommended to be used as such. |
| | | b. Fails Closed | Mechanical failure, loss of power. | No impact on System operation. Loss of ability to measure leakage remotely. | Valve position indication in C.R. | None | |
| 13. | Position Indicator for V1449 | False indication of valve position | Electro-mechanical failure. | Loss of ability to detect valve position in leakage detection line. | Drain from leakage detection system to graduated sump, increase in sump level shown valve is open. | None | |

APPENDIX 5A

NUCLEAR STEAM SUPPLY SYSTEM

OVERPRESSURE PROTECTION REPORT

FOR

FLORIDA POWER & LIGHT COMPANY

ST. LUCIE PLANT UNIT NO. 1

COMBUSTION ENGINEERING, INC
Combustion Division

Windsor Connecticut

Prepared by [vincent Callaghan] Date [9/20/72]

Approved by [James F. Olsen] Date [9/20/72]

Approved by [A. S. Jamison] Date [9/21/72]

Transmitted herewith is the documentation of the overpressure protection provided for the Combustion Engineering pressurized water nuclear steam supply systems. Included in this submittal are the detailed design parameters for the primary and secondary safety valves as well as a general report defining the methods of analysis utilized in determining the design and adequacy of overpressure protection systems. The detailed design parameters submitted in conjunction with the descriptive analysis fulfill the requirements set forth in the ASME Boiler and Pressure Vessel Code, Section III for the St. Lucie Plant Unit No. 1 nuclear steam supply system overpressure protection report.

Note: An Overpressurization Mitigation System has been added. See Section 7.6.1.3.

ABSTRACT

This report documents the adequacy of overpressure protection provided for the steam generators and reactor coolant system. Overpressurization of the reactor coolant system and steam generators is precluded by means of pressurizer safety valves, main steam safety valves and the reactor protective system. Pressure relief capacity for the main steam and reactor coolant systems is conservatively sized to satisfy the overpressure requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1968 Edition, Summer 1969 Addenda, Article 9. The safety valves in conjunction with the reactor protective system are designed to provide overpressure protection for a loss of load accident with a delayed reactor trip.

NOTE: The information provided in this appendix was developed for the licensing of the unit during the design phase. Some of this information may be considered historical since it has been superceded elsewhere in the UFSAR.

INTRODUCTION

Overpressure protection for steam generators and reactor coolant system is in accordance with the requirements set forth in the ASME Boiler and Pressure Vessel Code, Section III. Overpressure protection is ensured by means of pressurizer safety valves, main steam safety valves and the reactor protective system. Analyses of all reactor and steam plant transients causing pressure excursions have been made and the worst case transient, loss of load, in conjunction with a delayed reactor trip is the design basis for the pressurizer safety valves. The pressurizer safety valves, main steam safety valves and reactor protective system maintain reactor coolant system pressure below 110% of design pressure during the worst case transient. The main steam safety valves are sized to pass a steam flow corresponding to 105% of the plant rated power level. Steam generator pressure is limited to less than 110% of steam generator design pressure during the worst case transient.

## ANALYSIS

### Method

Combustion Engineering has performed a parametric study to determine the design basis incident for sizing the pressurizer safety valves. The design basis incident, loss of load with a delayed reactor trip, is then studied for each plant to define the sizing of the safety valves.

The transient code used in sizing the safety valves is the SURGE digital computer program and not the CESEC computer program. Comparison of the predicted variation of plant parameters during several transients using the SURGE program with actual measured data on the Palisades plant are presented on Figures 5A-5 through 5A-18. Currently, CE is in the process of comparing predicted plant transient parameters using the CESEC Code simulation with operating data from the Fort Calhoun plant and will submit this information when the analysis is finalized on a generic basis for demonstrating the accuracy of the predictive methodology.

The SURGE code is the result of continuous CE engineering effort to develop an accurate and reliable nuclear steam supply system (NSSS) transient analysis model. The SURGE code is a single heat transfer loop code which divides the reactor coolant system into four VOLUMES; reactor core, hot plena and pipe, steam generator tubes and cold plena and pipe. The secondary side of the steam generators is a four mode representation. The two region pressurizer representation consists of a steam volume and a water volume.

### Neutron Kinetics

A one-group point kinetics representation with six delayed neutron groups is used to determine the transient neutron flux. Non-linear Doppler and moderator temperature dependent feedback are considered. Control and shutdown rods and decay heat generation are included. Provisions have been made for inputting time dependent reactivity, neutron lifetime, delayed neutron fraction and precursor decay constants. Tables of non-linear functions of rod worth versus position and Doppler and moderator worth versus temperature can also be included as code inputs.

### Fuel Temperature Model

SURGE uses a two nodal fuel model. First order differential equations are used to describe the heat transfer process and to determine the two nodal fuel temperatures. Specific heats and heat transfer coefficients are supplied through inputs for each of the nodes.

Reactor Coolant Loop Flow Equations

The conservation equations of mass and energy are written for each of the four regions of the reactor coolant system. The four regions interact by mass and energy transport across adjacent boundaries. These equations are used to calculate the inlet and exit temperatures of reactor coolant and of steam generator coolant. The volume of each region, the fuel-to-core coolant heat transfer coefficient, the volumetric heat capacitances of the loop metal and the steam generator surface area are inputs of the code. The heat capacitances of the coolant are obtained from a temperature dependent algorithm in the code. A time dependent flow fraction may be input for varying the coolant flow. Constant pump volumetric flow is assumed in the cold leg. The volumetric flow rates in other elements are density corrected to achieve a constant system mass flow rate. The overall steam generator heat transfer coefficient is modified during reactor coolant flow coastdown and as changes in heat flux affect the boiling heat transfer coefficient.

Steam Generator Secondary Side

A four region model of the secondary side of the steam generator has been developed to accurately depict water level and pressure transients during NSSS thermal transients. Mass, energy and momentum balances are performed on each of the regions to satisfy the conservation laws. Incompressible flow is assumed in the downcomer region and a time delay is used to transport the mixed mean enthalpy from the feedwater ring to the tube bundle entrance. The evaporator consists of a subcooled and saturated region. A linear quality and uniform heat distribution are assumed throughout the region. Subcooled properties are defined in terms of a negative quality. This also allows defining the region in a continuous manner. The riser is modeled as a constant quality region with no heat addition. The steam drum region is assumed to be in a saturated, thermal equilibrium state. This eliminates the dependence on experimental data for evaporation and condensation rates between the liquid and steam volumes. The water level is established through a momentum balance around the secondary side and a mass balance in the steam drum. Hydraulic head, shock, frictional and acceleration losses are accounted for in performing the momentum balance. The Martinelli-Nelson multiplier is used to calculate frictional and shock losses in the evaporator and riser regions.

Pressurizer

The conservation equations of mass, energy and volume are written for both the steam region and the water region of the pressurizer. Together, these equations determine the water level and pressure transients. Reactor coolant system charging and letdown purification flows are included in the pressurizer mass balance.

The pressurizer spray flow is assumed to be 100% effective in condensing steam. When the steam space is at saturation conditions, the spray reaches saturation temperature and falls into the water volume. When the steam space is at superheat conditions, the spray totally evaporates into the steam region and never falls into the water volume. The mass flow rates across the steam-water interface are determined by dividing the change in steam formation (or collapse) in a given time step by the magnitude of the time step.

Plant Controls

The plant controls consist of a turbine admission valve, a pressure relieving system, a feedwater regulating system, a rod controller and a regulator for the pressurizer water level and pressure.

The turbine admission valve can be simulated by providing a curve of valve area versus time or by allowing the SURGE code to modulate a valve area based on an inputted power demand curve.

Pressure relieving valves are provided for both the pressurizer and the steam generator. The steam dump system is controlled from the reactor coolant average temperature as measured across the steam generators. The reference signal is the temperature corresponding to the demand power inputted into the code. Proportional opening and closing of the valves is governed by a linear temperature error program inputted into the code.

The bypass valve controls auctioneer between the steam dump temperature error signal described above and a secondary pressure signal to select the maximum bypass valve area.

Three pressurizer relief and/or safety valves and four secondary safety valve banks are also available as code input. These valves may be opened proportional to a pressure differential or they may be popped" open and "popped" closed at preset pressures.

Feedwater flow can be controlled by inputting a time dependent flow rate, by matching the feedwater with the steam flow or by selecting a three element controller. The three element controller operates on the error in the steam generator water level and the mismatch between the feedwater and steam flow rates. These error signals are combined to generate a signal to the feedwater valve which will open or close the valve to reduce the errors.

The input signals to the rod controller are temperature and power error measurement. Reactor coolant average temperature is measured across the steam generators and then compared with the demand average temperature. The demand signal is calculated from the demand power input and compared with the normalized flux to generate an error. The rod controller combines the two error signals with appropriate gains, and deadbands, to determine the direction and rate of rod motion.

Pressurizer water level and pressure are controlled by a charging-letdown system, by sprays and by heaters. The letdown valves are opened when the pressurizer water level exceeds the demand water level. The constant speed charging pumps are turned on when the pressurizer water level drops below the demand level. The level demand curve, letdown valve area versus level error, and charging pump capacities are all controlled through code inputs. Provision is also made for pump seal cooling water if utilized. In order to produce the correct NSSS mass balance, any charging flow or reactor coolant which is used for pump seal cooling and then discharged into the letdown system must not be added to NSSS mass inventory. SURGE code logic allows the operator to select the coolant system which is peculiar to the plant being analyzed.

A small amount of spray flow is added continuously to the pressurizer. The bulk of the spray flow is proportionally controlled-and is assumed to increase linearly between two pressure set points. The spray flow rates and pressure set points are code inputs. The transient response of the pressurizer heaters is governed by a first order differential equation, which includes heater heat capacities and heat transfer coefficients. These parameters are supplied as code inputs for both the proportional and backup heaters.

Reactor Trip Modes

In SURGE, there are seven trip modes: time in transient, high neutron flux, low reactor coolant flow, low steam generator water level, low steam generator pressure, high pressurizer pressure, and low pressurizer pressure. All trip set points are code inputs. A trip delay time is also available as code input.

Regenerative Heat Exchanger (RHX)

A model of the RRX has been included in SURGE to obtain charging nozzle and heat exchanger outlet flow temperature transients for design calculations and equipment specifications. These calculations are separate from and do not influence the NSSS analysis.

Assumptions

a. At onset of loss of load transient the reactor and steam systems are at design power level.

b. Positive moderator coefficients between $+0.5 \times 10^{-4}$ $\Delta$ K/K/F and $+1. \times 10^{-4}$ $\Delta$ K/K/F are used in the analysis. The coefficient ($1. \times 10^{-4}$ ) $\Delta$ K/K/F) giving worst case pressure power excursions is used. The moderator coefficient used is substantially more positive than will occur in actual plant operation. The expected value of the moderator temperature coefficient, is discussed in Section 4.3.2.3 (a), is $-0.4 \times 10^{-4}$ ) $\Delta\rho$/F at full design power conditions. The accident analyses discussed in Chapter 15 assume that the most positive moderator temperature coefficient that would be present is $+0.5 \times 10^{-5}$ $\Delta\rho$/F. Therefore, use of a moderator temperature coefficient as positive as $+1.0 \times 10^{-4}$ $\Delta\rho$/F is a conservative upper limit of the value of this coefficient.

c. A doppler coefficient of $-.8 \times 10^{-5}$ $\Delta$ K/K/F is used.

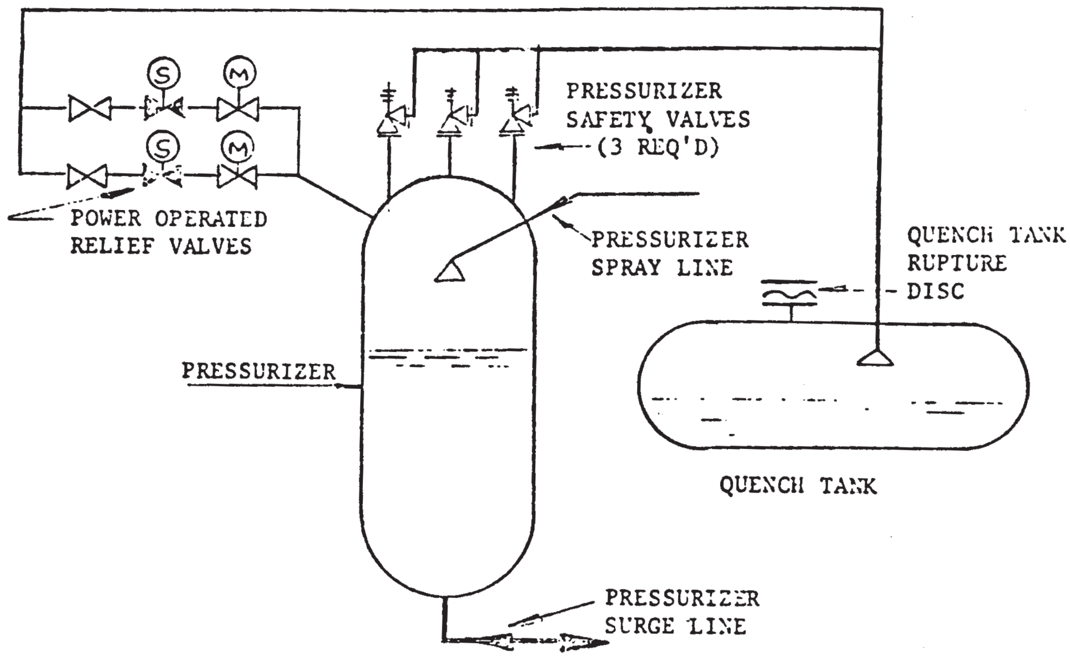
d. No credit is taken for letdown, charging, pressurizer spray, secondary dump and bypass, or feedwater addition after turbine trip.

e. The analysis includes plant instrumentation and safety valve setpoint errors.

f. Plant pressure at the onset of the incident is 2200 psia and the pressurizer water level is within normal operating limits.

Analyses show that the peak reactor coolant system pressure, as far as pressurizer safety valve sizing transients are concerned, is relatively insensitive to initial pressures within the operating range. A slight conservatism is realized when the transient is started from a lower pressure.

Pressurizer Safety Valve Sizing




A typical schematic diagram of the Combustion Engineering pressurizer, safety valves and quench tank is shown above. The safety valve inlet and discharge piping are sized to preclude unacceptable pressure drops and backpressure which would adversely affect valve operation.

The available discharge flow rate of the as-built safety valves, corresponding to a pressurizer pressure of 110 percent of design, is 75 percent more flow than is necessary to maintain RCS pressure.

The methodology utilized for the surge line pressure drop calculations is as follows (the definition of variables used are evident from the descriptions provided) :

a) The total mass in the reactor coolant system is computed as a function of time from the compressed water properties.

$$M(t)=\sum \rho v$$

b) The pure surge flow rate (RCS expansion) is determined from the change of mass inventory over a small time interval.

$$\dot{m}_s = \frac{M(t)-M(t-\Delta t)}{\Delta t}$$

c) The net surge flow rate into the pressurizer is computed by taking into account the effect of charging, letdown and spray flow rate.

$$\dot{m}_{ns} = \dot{m}_s + \dot{m}_{cp} - \dot{m}_{ld} - \dot{m}_{sp}$$

d) The pressure drop in the surge line (the difference between hot leg pressure and pressurizer pressure) is calculated by summation of the friction, shock, gravity, and acceleration losses.

$$P = \frac{M_{SL}}{A_{SL}} \frac{d}{dt}\left(\frac{\dot{m}_{ns}}{\rho A_{SL}}\right) + \rho H_{SL} + K_{SL} \frac{\left|\dot{m}_{ns}\right| \dot{m}_{ns}}{2g_c\, \rho (A_{SL})} 2$$

There is no direct correlation between surge flow and the sizing of the safety valves. However, the pressurizer analysis, whose results are used for safety valve sizing, does take surge flow into account.

The design basis incident for sizing the pressurizer safety valves is of turbine-generator load in which the reactor is not immediately tripped. The results of this calculation are presented as Figure 5A-19 through 22 depicting pressurizer level. pressurizer pressure, steam enthalpy and safety valve mass discharge rate as a function of time for the loss of load transient with delayed reactor trip. One of the design bases for the pressurizer provides for sizing such that only steam will be discharged through the safety valves during expected transients. This steam flow discharge rate is determined from the following expression:

$$\dot{m} = \frac{0.53\, A.P}{2.68\, x\, 10^{-4} \left(h_g - 185\right)}$$

where $A$ = safety valve area

$h_g$ = pressurizer steam enthalpy

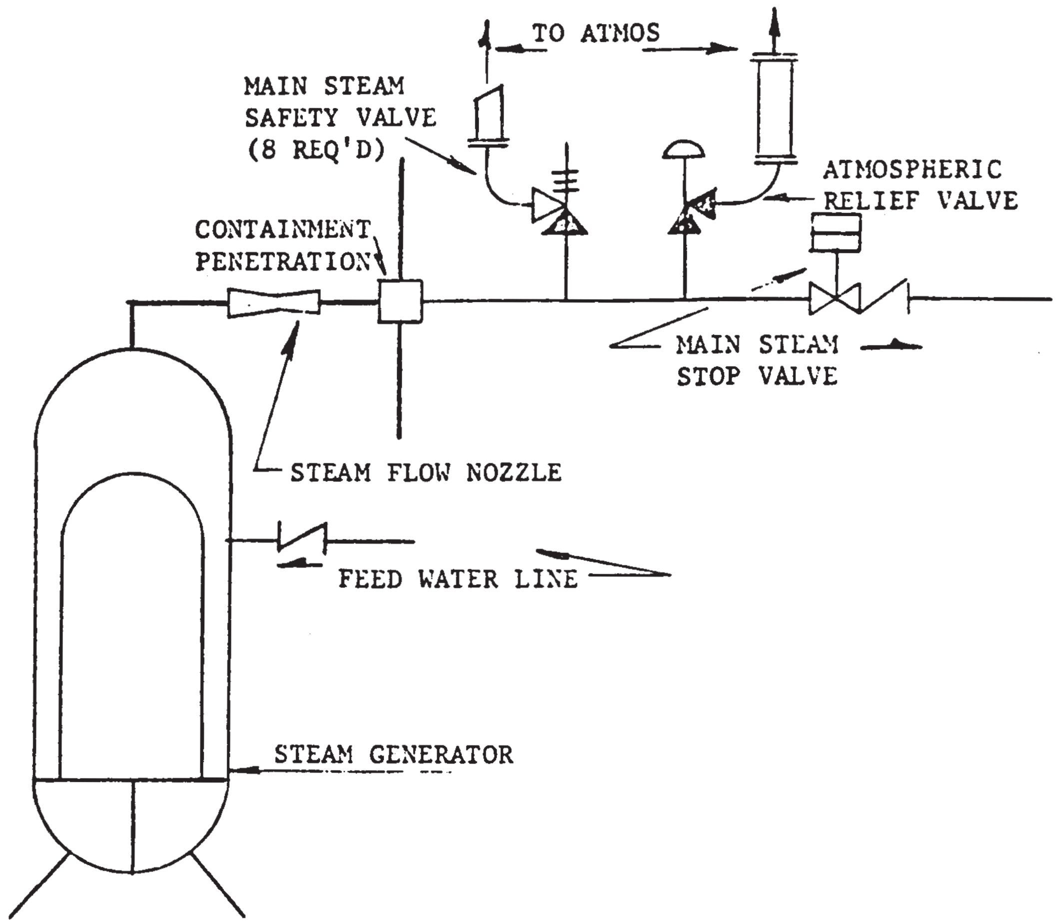
$\dot{m}$ = safety valve discharge rate

$P$ = pressurizer pressure minus line losses.

During the over pressurization transient the safety valves passed 95% of rated capacity as determined through certification tests. No credit is taken for any pressure reducing devices except the pressurizer and main steam safety valves. In reality the incident would be terminated by a number of reactor trips. These include:

a. Reactor trip on turbine trip
b. High reactor power trip
c. Steam generator low water level trip
d. High pressurizer pressure trip
e. Manual Trip

Main Steam Safety Valve Sizing




The discharge piping from the safety valves is designed to accommodate rated relief capacity without imposing unacceptable backpressure on the safety valves. The main steam safety valves are sized to pass the steam, flow at 105% of the plant rated power level. This limits steam generator pressure to 110% of steam generator design pressure during worst case transients. The main steam safety valves consist of several banks of valves with staggered set point pressures. The safety valves are spring loaded bellows type in compliance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III.

The Pressurizer Code Safety Valves blowdown is set to 10% per CEN-227, “Summary Report on the Operability of Pressurizer Safety Valves in CE Designed Plants” and letter L-86-114. Blowdown is set to prevent excessive loss of mass from the system while minimizing the number of rapid pressure transients required to control overpressurization. The maximum allowable blowdown was calculated to be 20% with the resultant margin after swelling at 11%. Therefore a blowdown setting of 10% is acceptable for the PSVs. EC293169

Figure I depicts a typical steam generator pressure transient for a worst case loss-of-load incident. As can be seen in Figure 1 the steam generator pressure remains below 110% of design pressure during the incident.

In order to determine the effects beyond the point where delayed reactor trips would have terminated the incident, the calculation is allowed to continue until the pressurizer fills or the steam generator boils dry.

A series of loss-of-load studies are evaluated for a range of safety valve sizes. Figure 2 shows that after the safety valve capacity increases to a certain size, additional increase in capacity has negligible effect in reducing the maximum system pressure experienced during the loss-of-load transient. The pressurizer safety valve size, i.e., capacity is chosen so as to minimize the maximum pressure during the loss-of-load transient. The minimum specified safety valve capacity is identified on Figure 2.

Figures 3 and 4 present curves of maximum reactor coolant system pressure and core power vs. time for the worst case loss of turbine generator load. Figure 3 shows that the maximum pressure remains below 110% of design pressure during this worst case transient. Following turbine trip, the reactor continues at increasing power (See Figure 4) due to the conservatively assumed moderator and Doppler coefficient. Reactor coolant temperature rises and expands coolant into the pressurizer causing an increase in pressure as the steam space is compressed.

Figure 1 shows main steam safety valves begin opening at approximately 4.2 seconds and at 11.5 seconds all of the secondary relief capacity is utilized. The main steam safety valves remove energy from the reactor coolant system and thus mitigate the pressure surge. The pressurizer safety valves open at the reactor coolant system design pressure approximately 5 seconds after initiation. The combined action of the pressurizer and main steam safety valves and the reacts. protective system limits the reactor coolant system pressure to less than 110% of design pressure.

## COMPARISON OF CALCULATED PLANT <u>TRANSIENTS WITH PALISADES DATA</u>

Transient test date from the Palisades Plant were used to evaluate the adequacy of the analytical techniques. The analysis included an evaluation of the following transients:

Generator Trip
-5% per minute power ramp
-10% power step
+10% power step

These transients were analyzed by two methods using the SURGE computer code. First, the code input was actual test conditions as well as they are known and second, the plant design parameters were used in the simulations. The second mode is the usual manner for performing the thermal transients for design purposes.  Figure 5A-5 through 5A-18 show the results of the analyses.

In simulating the Palisades tests, one major item was to reproduce the correct power transient. For the 5%/minute ramp test, the power curve was reproduced rather easily because the transient is of a relatively slow changing nature. For the ± 10% power step and steam generator trip cases, the control rod speed and reactivity worth and moderator worth were adjusted until the power curve was in reasonable agreement with the test data. Duplicating the pressurizer spray and heater response was also required.

It was known during the tests that the pressurizer auxiliary spray leaked, but the leakage rate was unknown. To compensate for this leakage, a portion of the heaters were energized by the plant operators a good deal of the time.

A problem occurred during the test with the secondary steam dump system with the valves unpredictably opening and closing and this caused some trouble in analyzing the steam generator trip test. This effect could not be assessed.

For the ± 10% step, 5%/minute ramp, and steam generator trip cases two analyses were performed. In one the actual plant operating conditions were utilized in the SURGE code as closely as possible. In the other, design data were used, (i.e., temperatures, pressures, and controller setpoints) in the usual manner for the transients. The latter procedure was to demonstrate how the "design based" analysis compares with the tests and in general the trends of the transients were seen to be similar and the magnitudes of change in parameters greater for the "design base." It was concluded that the Palisades' specification thermal transients are generated conservatively for component design purposes.

As can be seen from the figures, system responses to load changes were generally not dramatic for these tests. Therefore, when the analytical results are quantitatively compared to test data, the differences tend to be magnified.

EFFECT OF REPLACEMENT STEAM GENERATORS

The design basis accident for sizing the pressurizer safety valves is loss of load with a delayed reactor trip. The worst initial plant condition for this event is full power with maximum tube plugging (lowest initial secondary pressure). The St. Lucie 1 response to a loss of load with the replacement steam generators (RSGs) and 18% tube plugging is bounded by the analysis presented in Section 15.2.7. Consequently, the conclusions remain valid for St. Lucie 1 with the RSGs.

## CONCLUSIONS

The steam generators and reactor coolant system are protected from overpressurization in accordance with the guidelines set forth in the ASME Boiler and Pressure Vessel Code, Section III. Peak reactor coolant system and main steam system pressures are limited to 110% of design pressures during worst case loss of turbine-generator load. Overpressure protection is afforded by pressurizer safety valves, main steam safety valves and the reactor protective system.

TABLE 5A-1

SAFETY VALVE RELIEF CAPACITIES

| Standard Plant Rating Mth | Pressurizer Relief Capacity lb/hr |
|---|---|
| 1425 | 400000 |
| 2570 | 592000 |
| 2770 | 790000 |
| 3410 | 920000 |
| 3473 | 937000 |

Project: St. Lucie System: Reactor Coolant

CE Contract No.: Unit No. 1 – 19367 CE P&ID: 19367-210-110

Architect/Engineering Firm: Ebasco Service

Safety Valve No.: V1201, V1202/V8201 through V8216 Safety Valve Name: Pressurizer Safety/ Main Steam Safety

EQUIPMENT PROTECTED BY SAFETY VALVES

| Name | Design Pressure | Design Temperature |
|---|---|---|
| Reactor Coolant System | 2485 psig | 650ºF (700ºF for pressure, for surge line and relief valve inlet) |
| Steam Generator and Main Steam Piping | 985 psig | 550ºF |

Pressurizer Safety Valve Specifications

| | Pressure | Temperature |
|---|---|---|
| Normal Operating | 2235 psig | 650ºF |
| Maximum Operating | 2335 psig | 653ºF |

Safety Valve Set Pressure 2485 psig ± 1% Minimum Operating Pressure Margin 215 psi

Accumulation 3% of set Pressure: Blowdown 10% of set pressure EC 293169

Pressure Sources Loss of Turbine Load

Design Capacity: 200,000 lb/hr each basis of design capacity loss of turbine load without simultaneous reactor trip.

Assumptions and Restrictions The only other pressure relieving devices which are the main steam safety valves.

Safety Valve Inlet Line Conditions

Pressure Drop at Design Capacity 50 psi

Flowing Fluid Saturated Steam

Safety Valve OutetLine Conditions

Normal Superimposed Back Pressure 300 psig

Normal Fluid Conditions gas

Valve Data

Manufacturer Crosby Valve & Gage Co.

Catalog No. Special

| Connections: | Inlet | Outlet |
|---|---|---|
| Size | 3" | 6" |

Type Flange, Sm. Tg. Raised Face

Maximum Back Pressure Buildup 515 psig

Flowing Fluid: Wet Steam

Rating 2500# USASI 300# USASI

Valve Pressure Rating 2500 psig

Valve Temperature Rating 700$^0$F

Back Pressure Compensation: Yes

Totally Enclosed: Yes

Gagging Device: Yes

Orifice Size: 2.545 in$^2$

Main Steam Safety Valve Specifications

| | Pressure | Temperature |
|---|---|---|
| Normal Operating | 800 psig | 521 F |
| Maximum Operating | 985 psig | 550 F |

Safety Valve Set Pressure Note 1

Minimum Operating Pressure Margin 175 psig

Accumulation 3% of set pressure: Blowdown 4% of set pressure

Pressure Sources

Loss of Turbine Load

Design Capacity 744,000 lb/hr each basis of design capacity loss of turbine load without simultaneous reactor trip. Reactor trips on high pressurizer pressure.

Assumptions and Restrictions The only other pressure relieving devices which function are the pressurizer safety valves.

Safety Valve Inlet Line Conditions

Pressure Drop at Design Capacity ≈ 0 psi

Flowing Fluid Saturated Steam

Safety Valve Outlet Line Conditions

Normal Superimposed Back Pressure 0 psig

Normal Fluid Conditions Air

Maximum Back Pressure 40 psig

Flowing Fluid Wet Steam

Note 1: 1st Bank 1000psia, 8 valves

2nd Bank 1040psia, 8 valves

Total Number of Valves Equals 16

Valve Data

Manufacturer Crosby Valve & Gage Co.

Catalog No. Special

| Connections | Inlet | Outlet |
|---|---|---|
| Size | 6" | 10" |

Type Flange, Sm.Tg. Raised Face

Rating 1500# ASA/150# ASA

Valve Pressure Rating 1200 psig

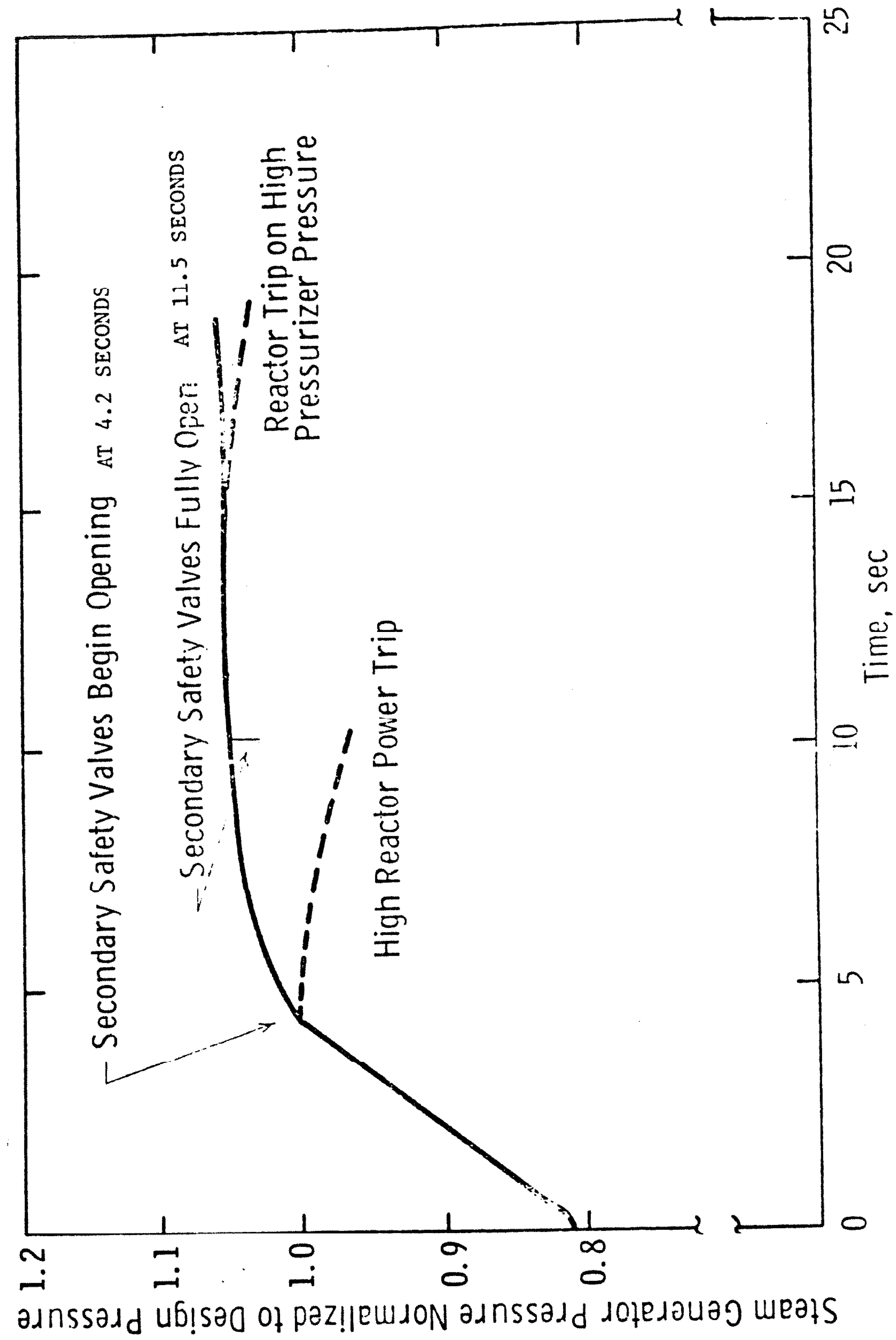
Valve Temperature Rating 550$^o$F

Back Pressure Compensation No

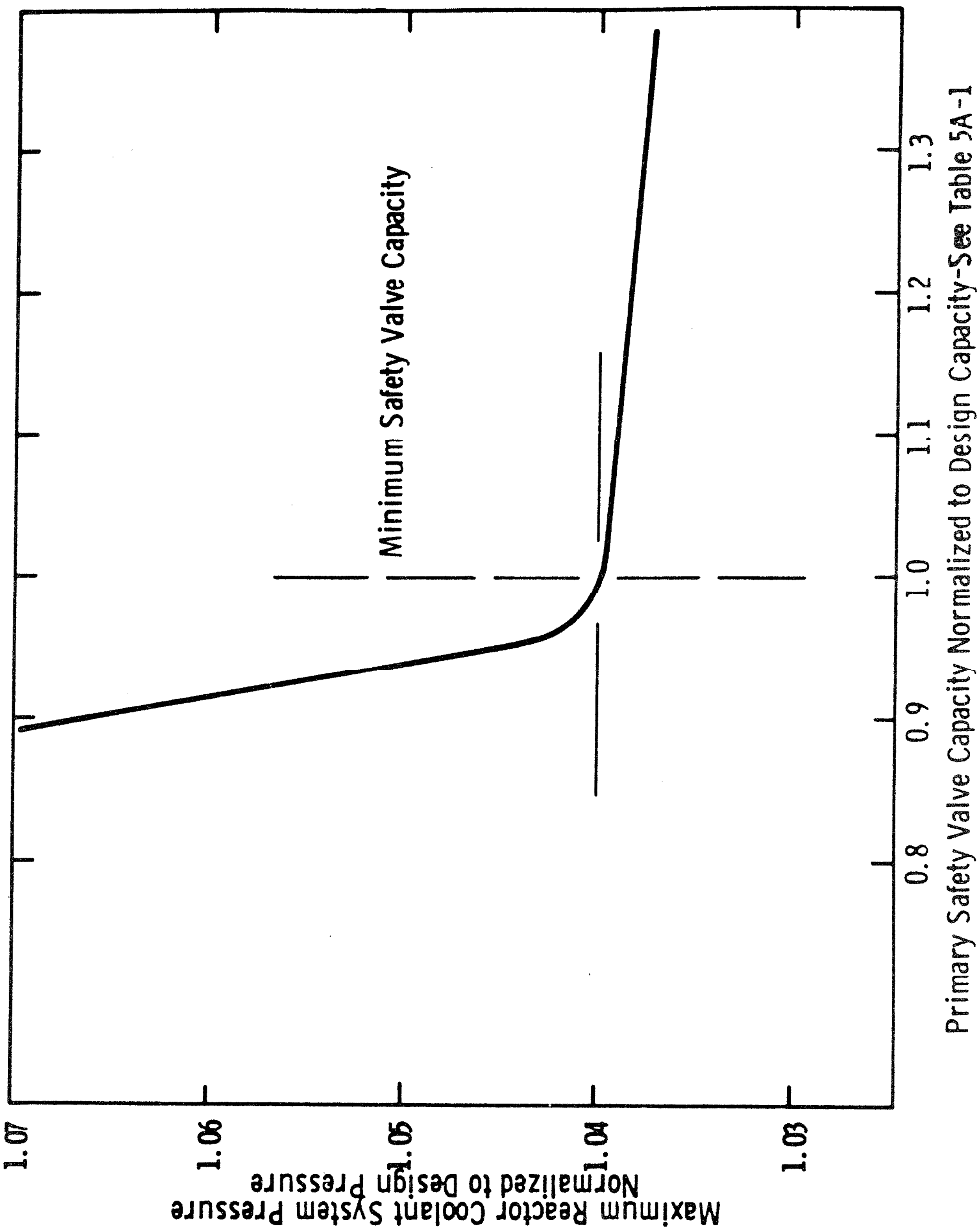
Totally Enclosed No

Gagging Device Yes

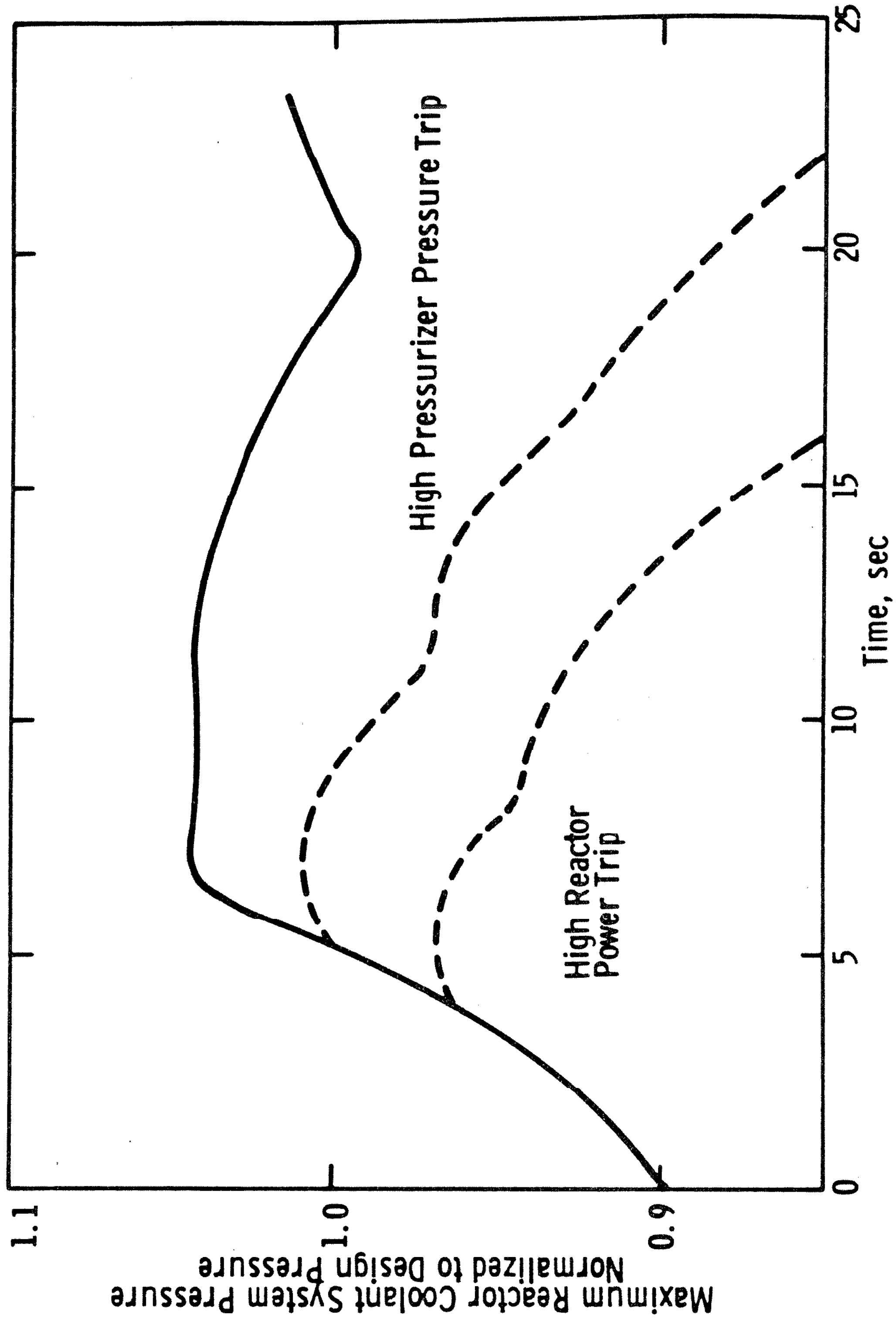
Origice Size 16 in$^2$



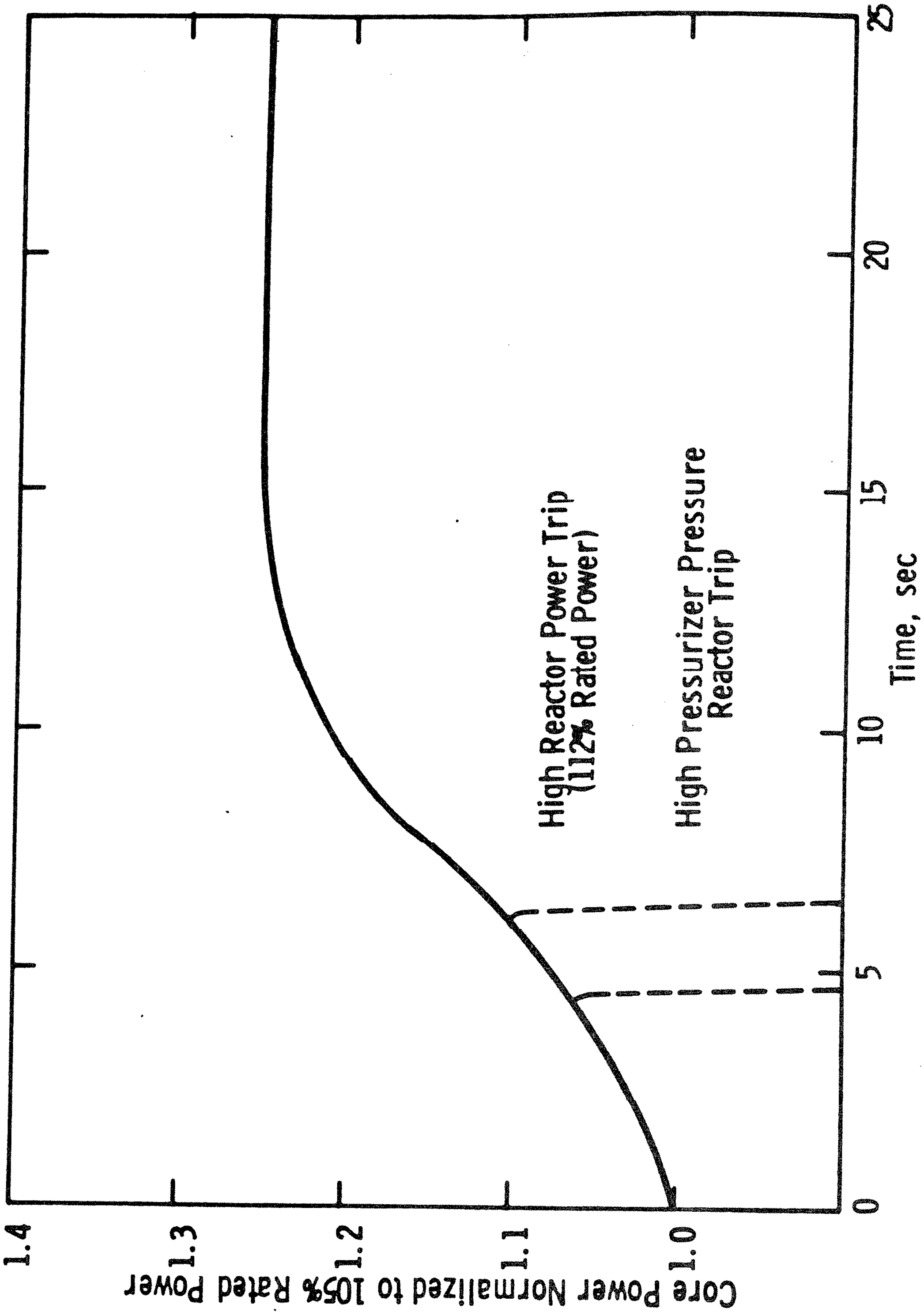

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Steam Generator Pressure Complete Loss of Turbine - Generator Load With Delayed Reactor Trip | Figure 5A-1 |
|---|---|---|



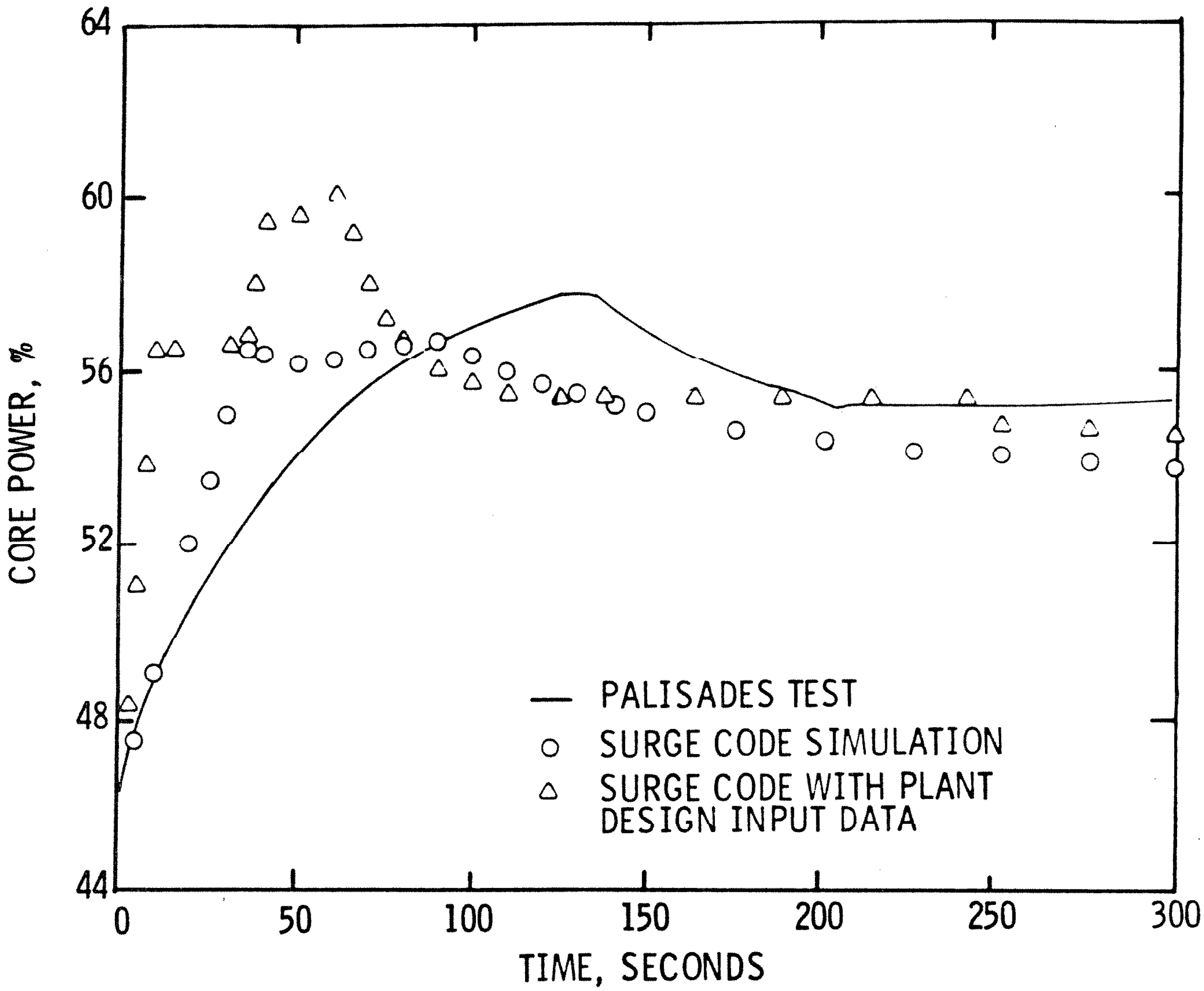

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Optimized Safety Valve Sizing | Figure 5A-2 |



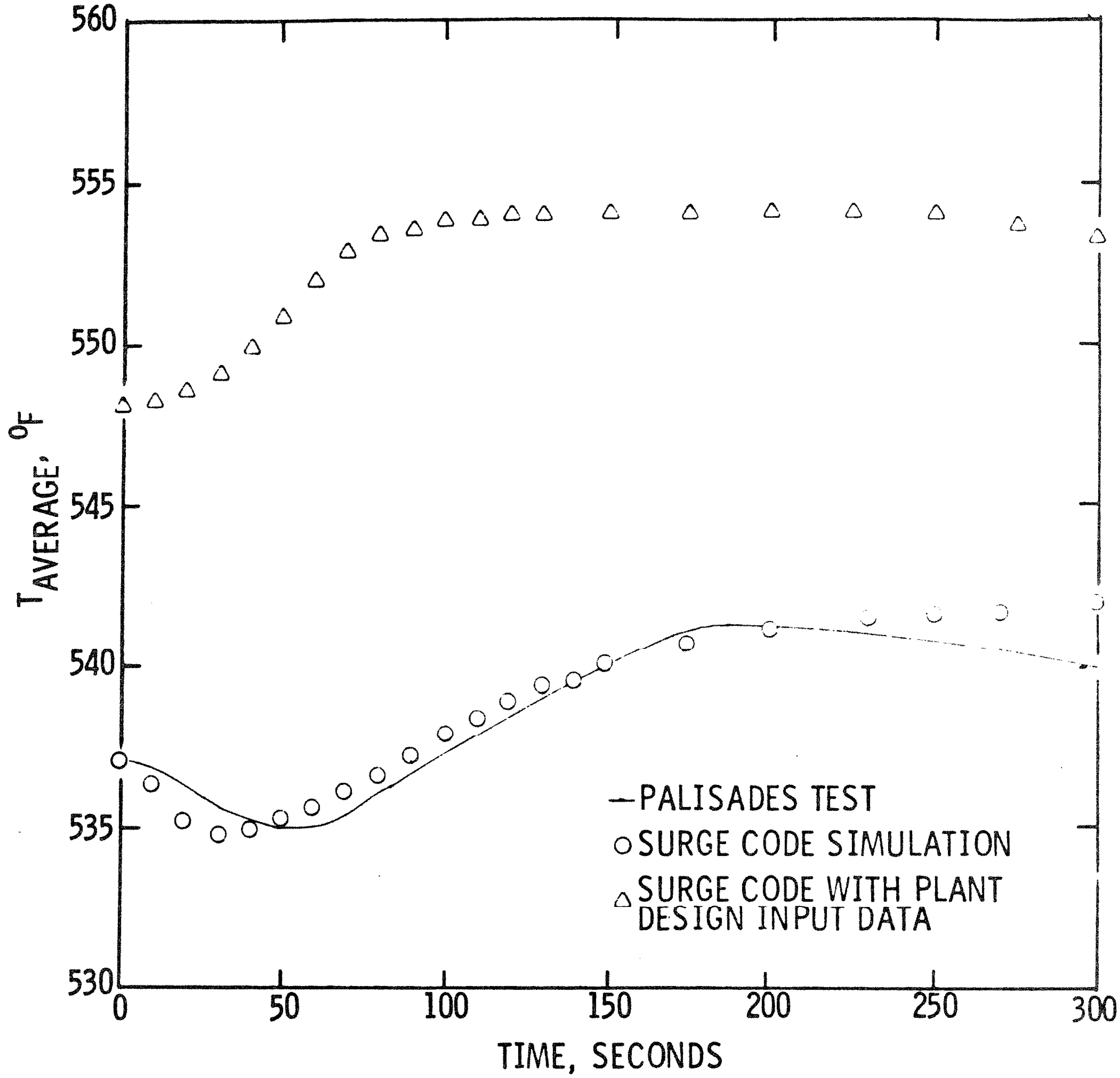

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Maximum Reactor Coolant System Pressure vs Time for Worst Case Loss of Load Incident With Delayed Reactor Trip | Figure 5A-3 |



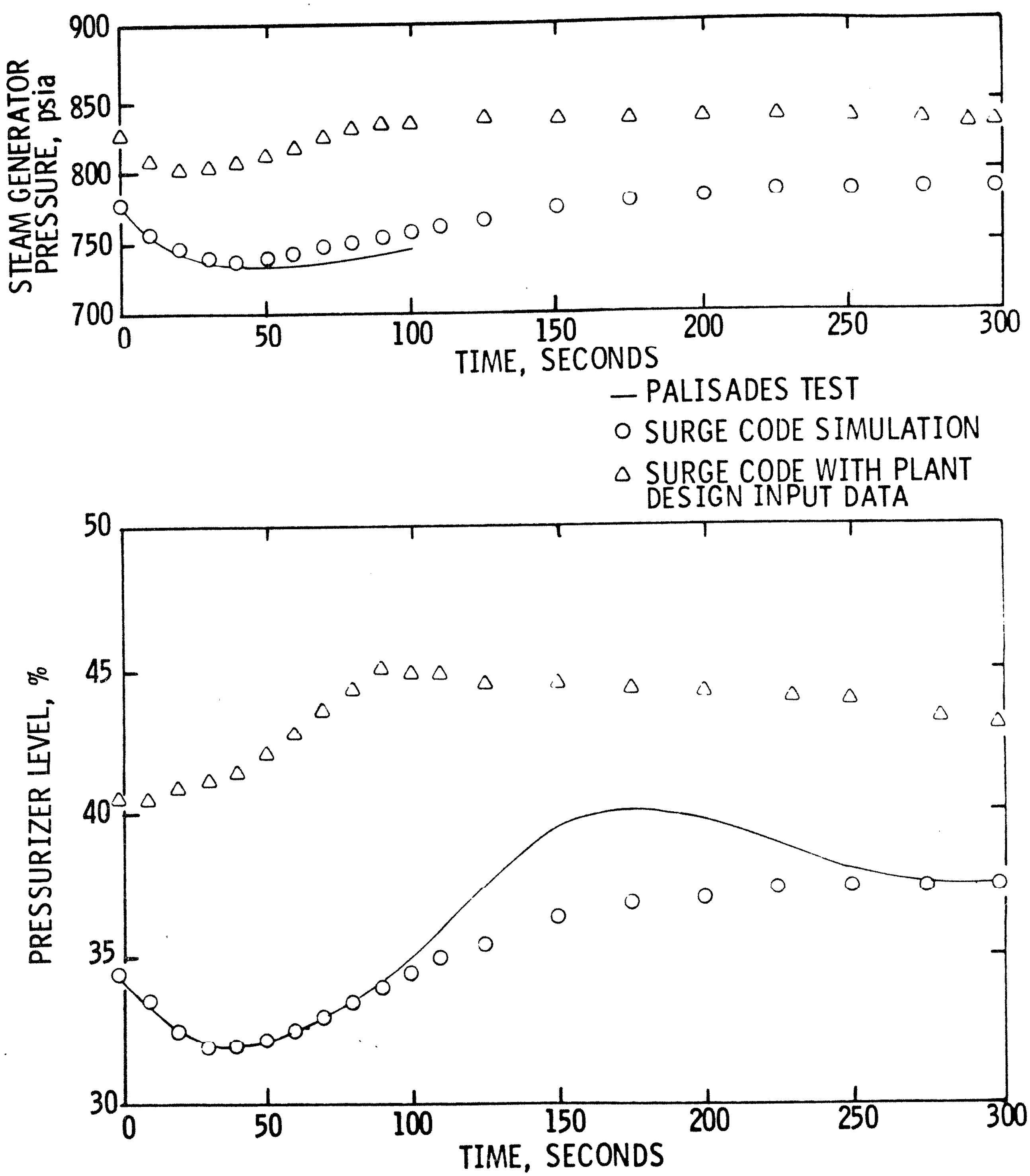

| FLORIDA POWER & LIGHT CO. St. Lucie Plant | Maximum Reactor Power vs Time for Worst Case Loss of Load Incident | Figure 5A-4 |
|---|---|---|



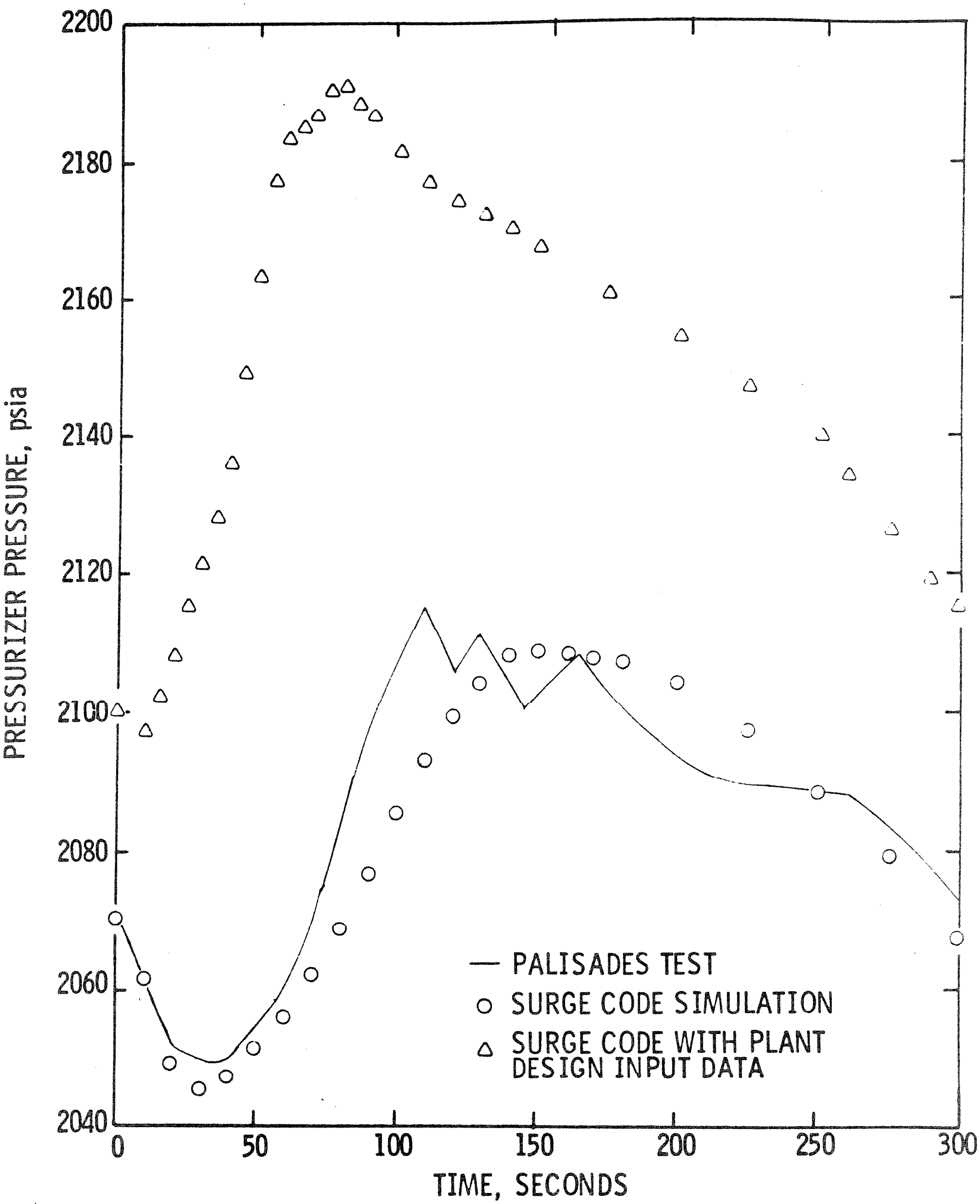

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | +10% POWER STEP | Figure 5A - 5 |



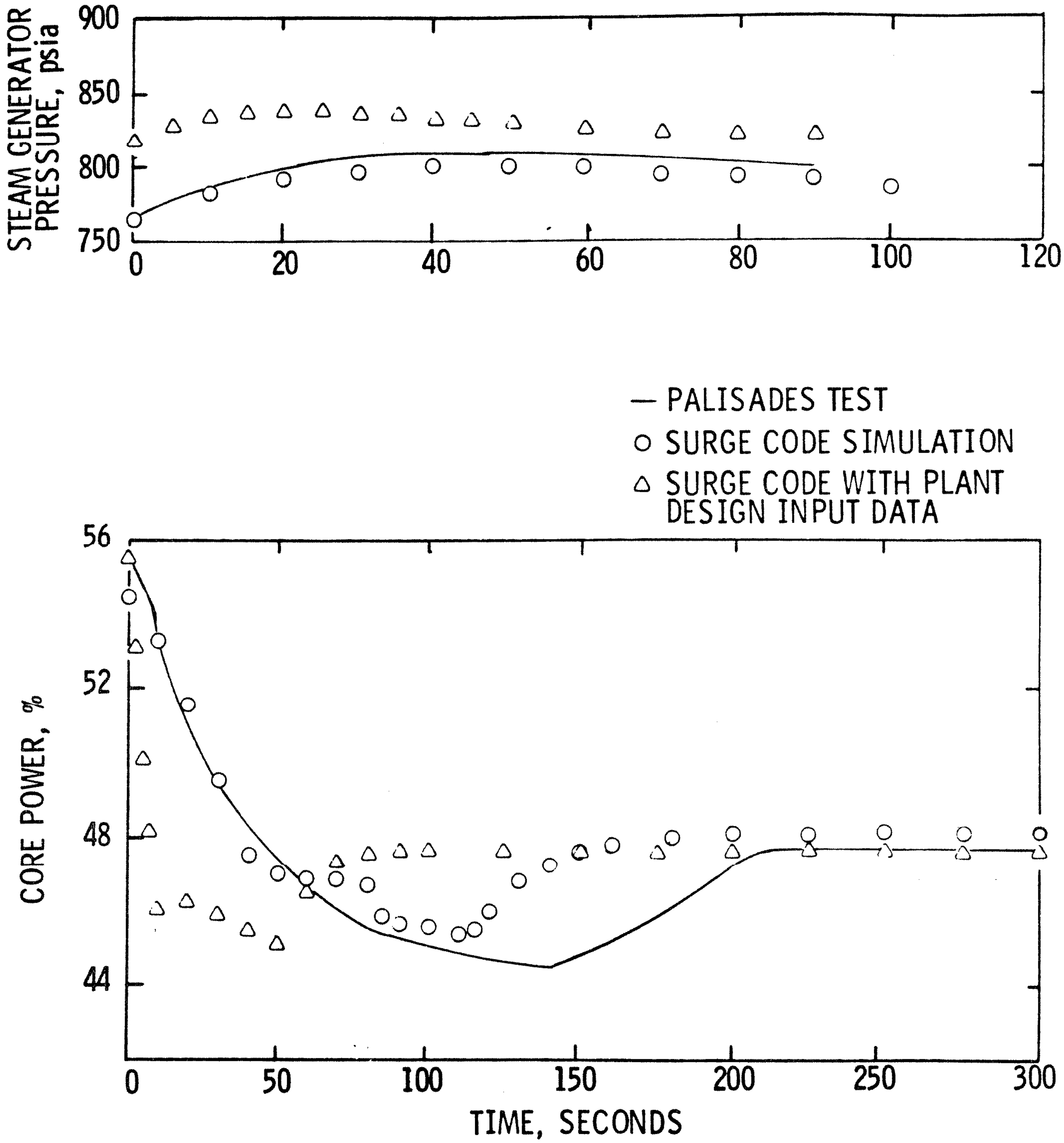

| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | +10% POWER STEP | Figure 5A - 6 |
|---|---|---|



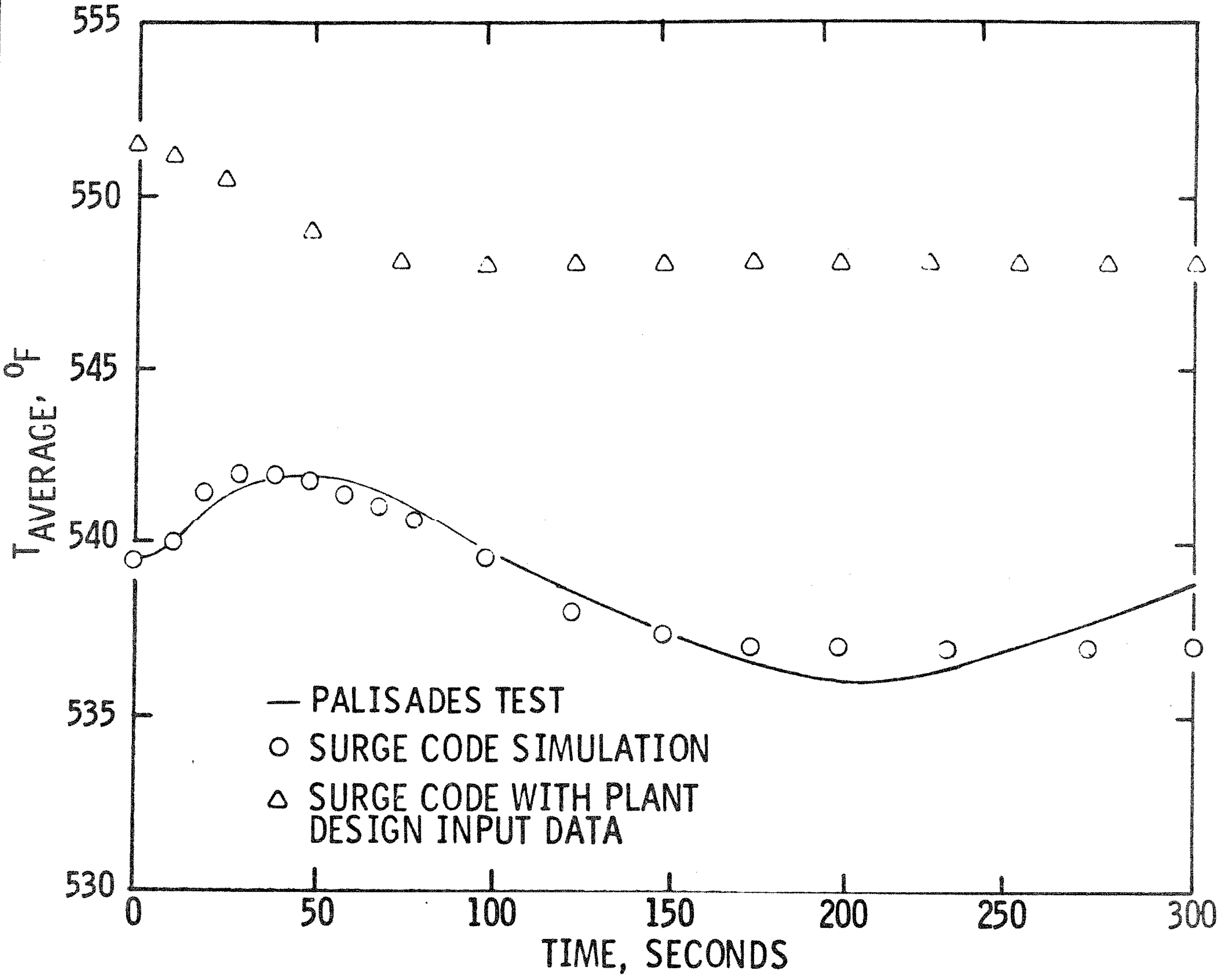

| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | +10% POWER STEP | Figure 5A - 7 |
| --- | --- | --- |



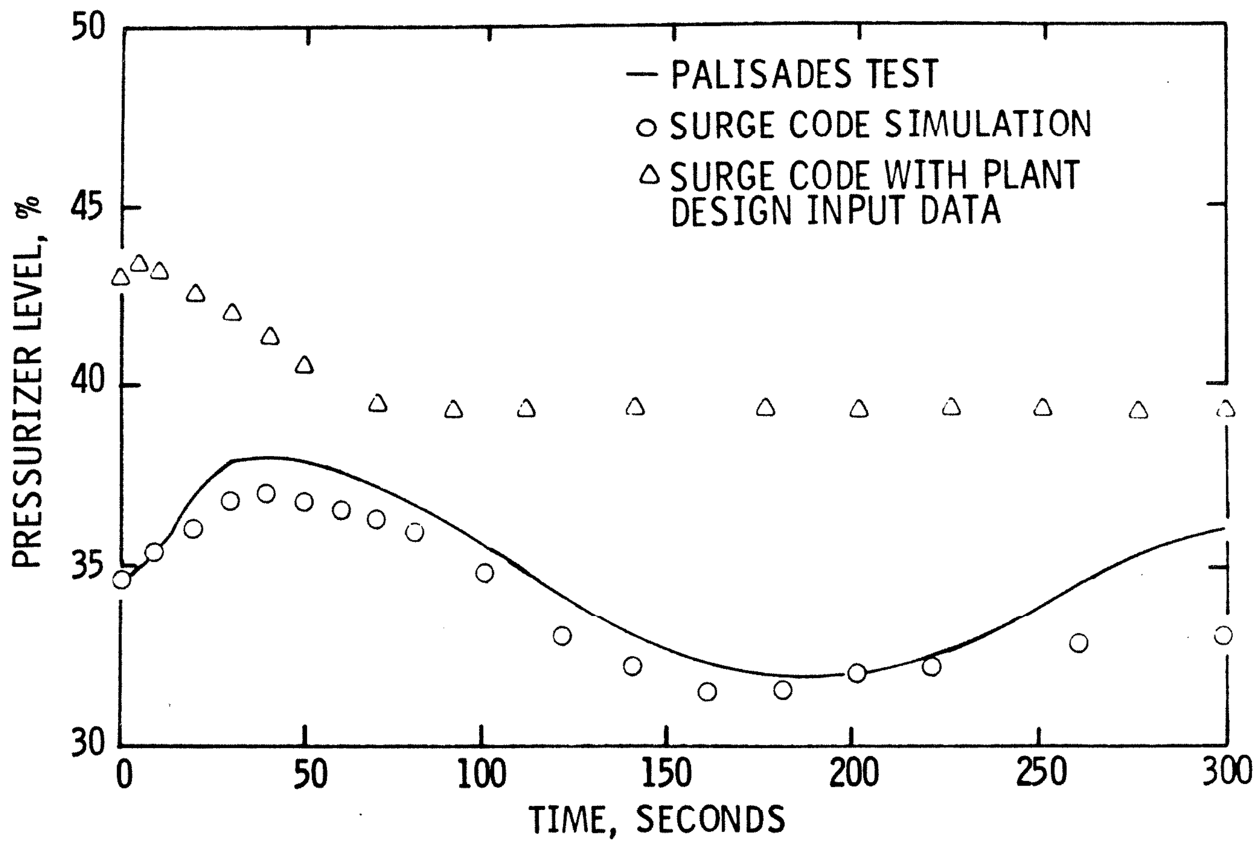

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | +10% POWER STEP | Figure 5A - 8 |



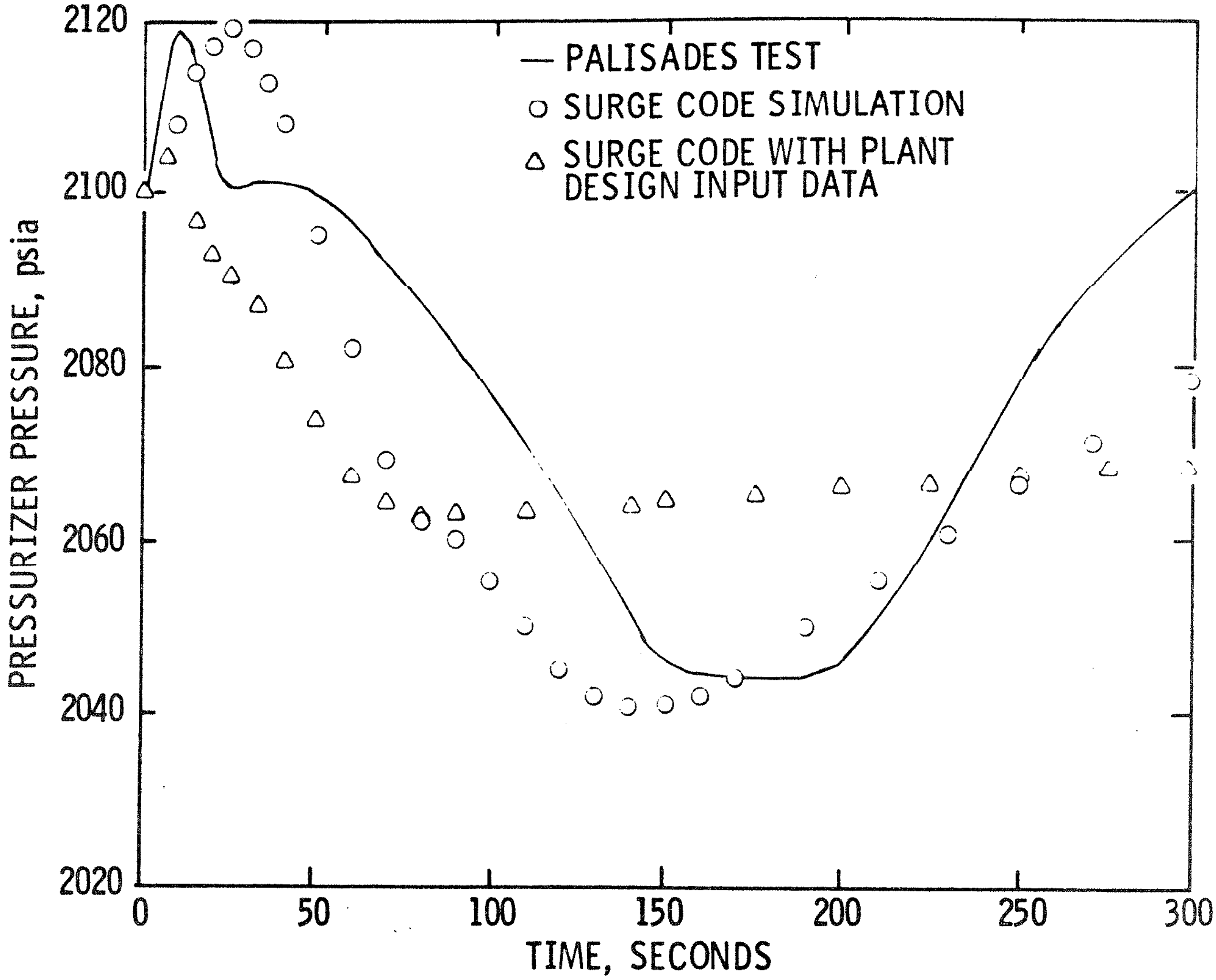

| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | -10% POWER STEP | Figure 5A - 9 |
|---|---|---|



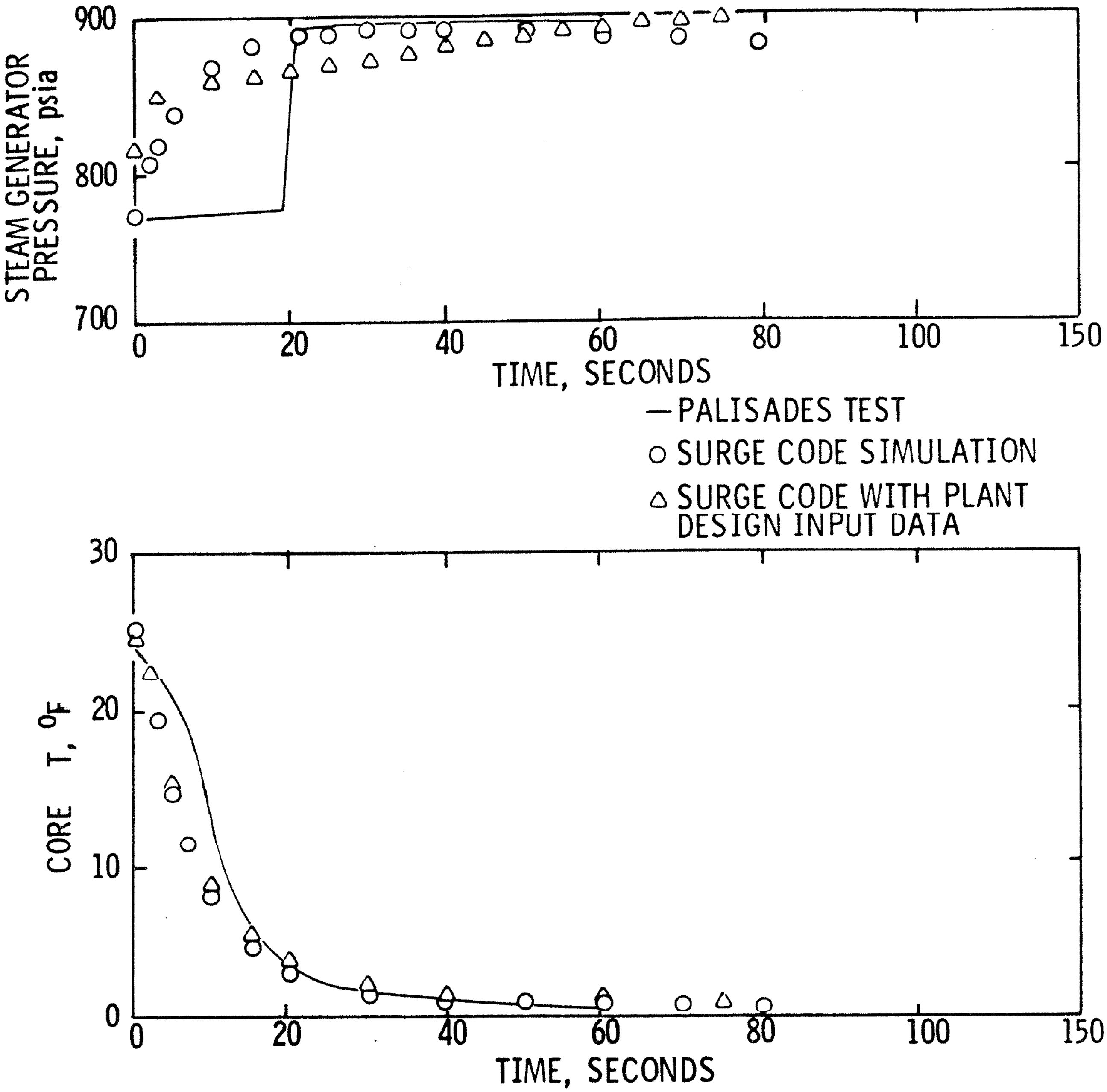

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | -10% POWER STEP | Figure 5A - 10 |



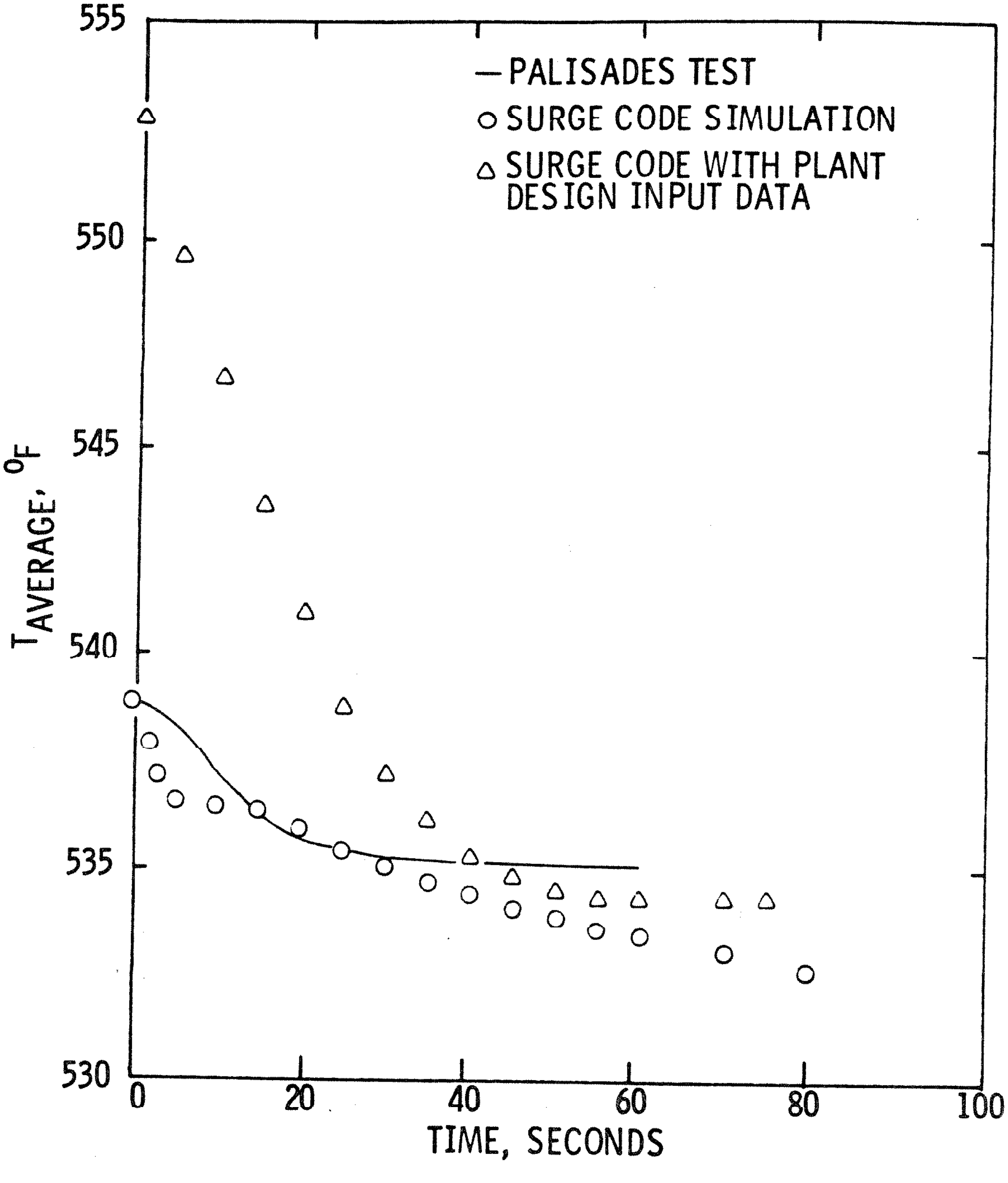

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | -10% POWER STEP | Figure 5A - 11 |



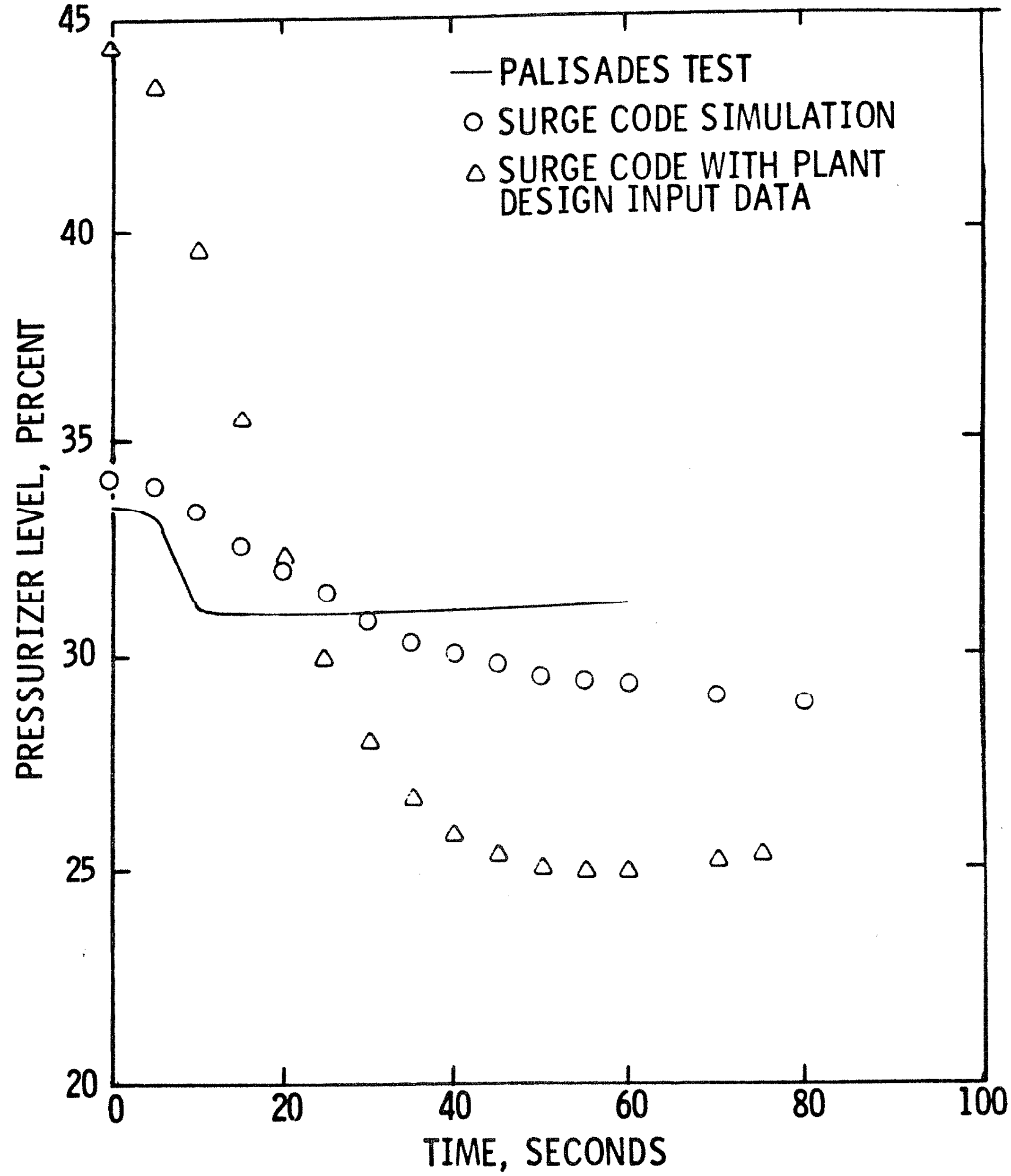

| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | -10% POWER STEP | Figure 5A - 12 |
|---|---|---|



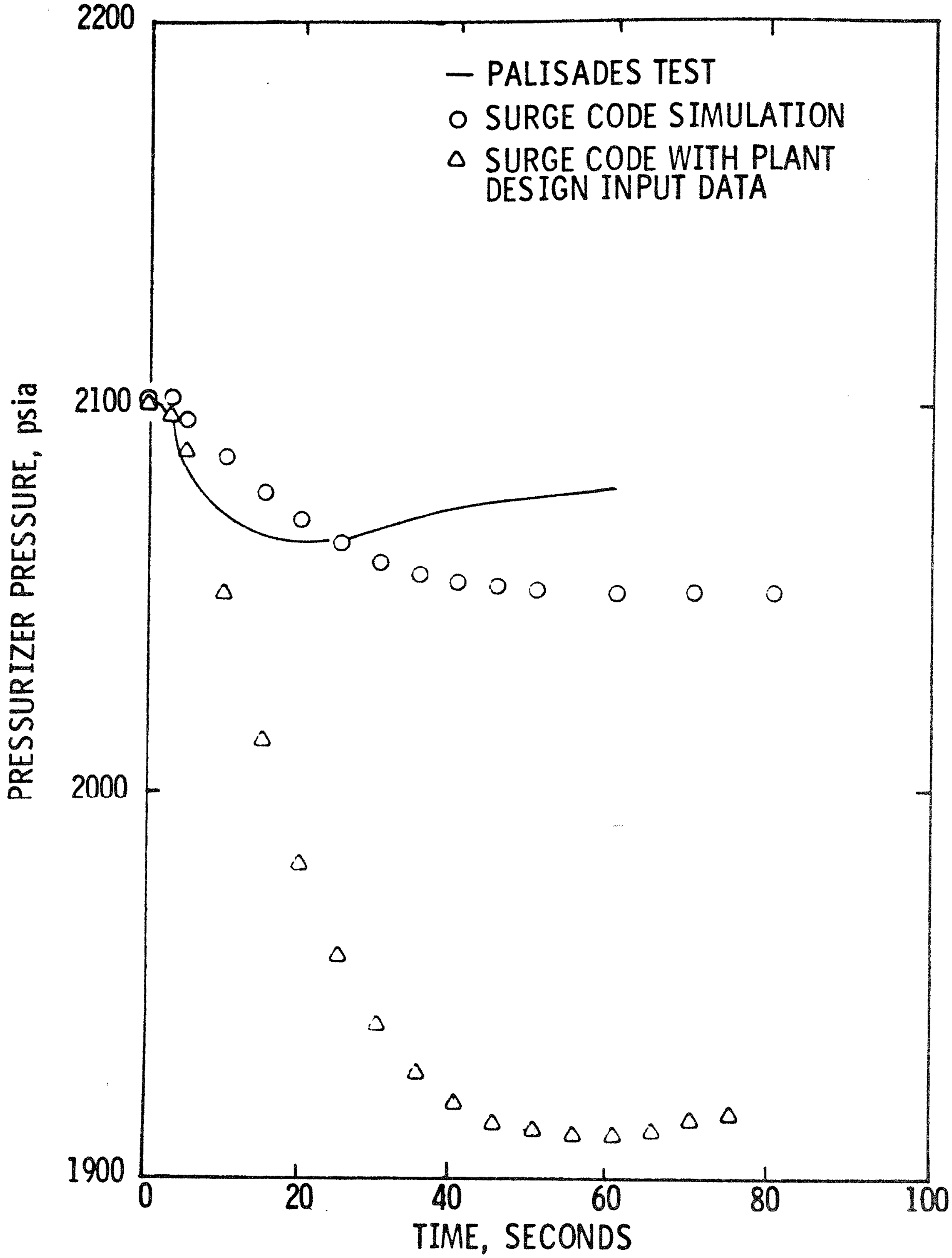

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | GENERATOR TRIP | Figure 5A - 13 |



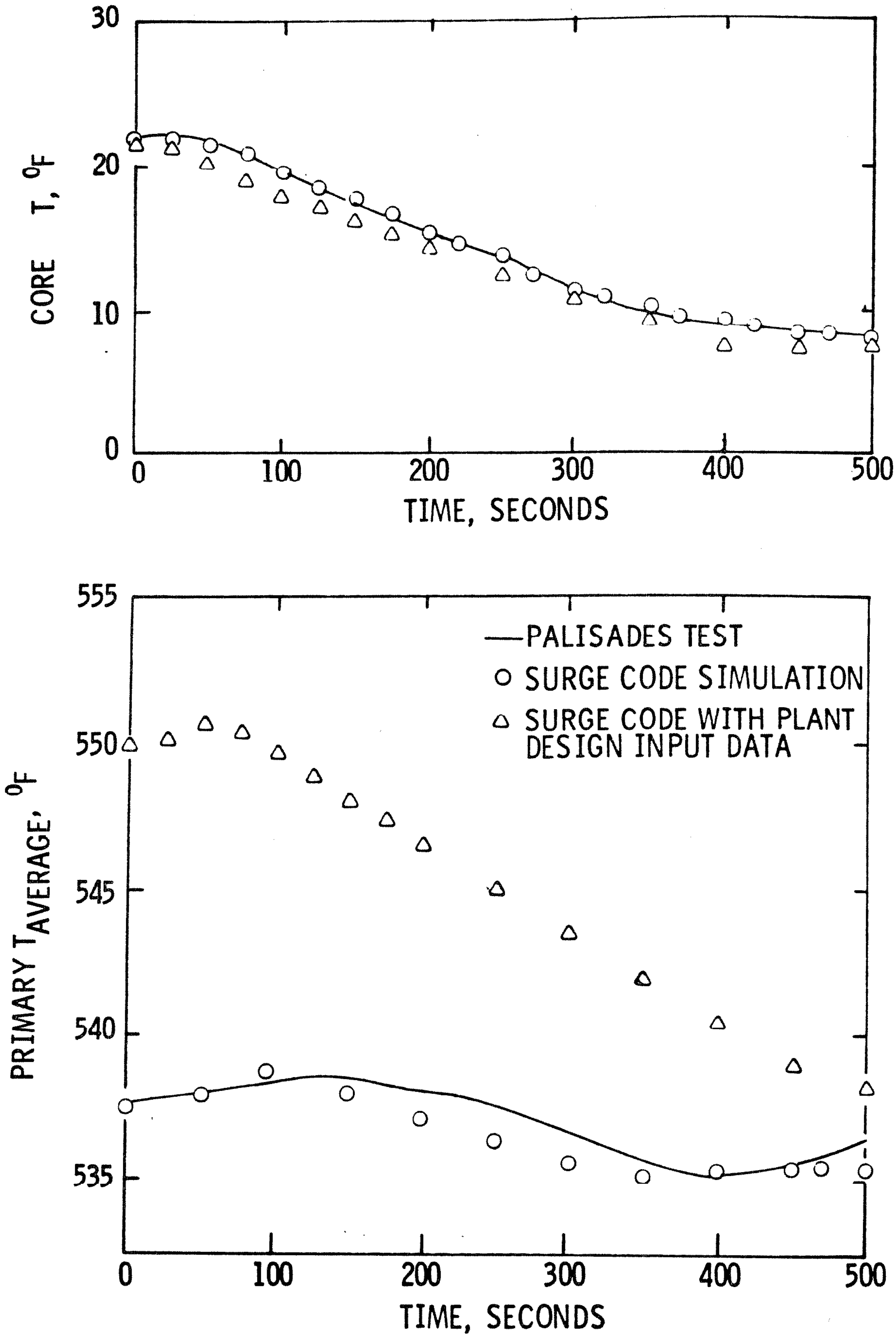

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | GENERATOR TRIP | Figure 5A - 14 |



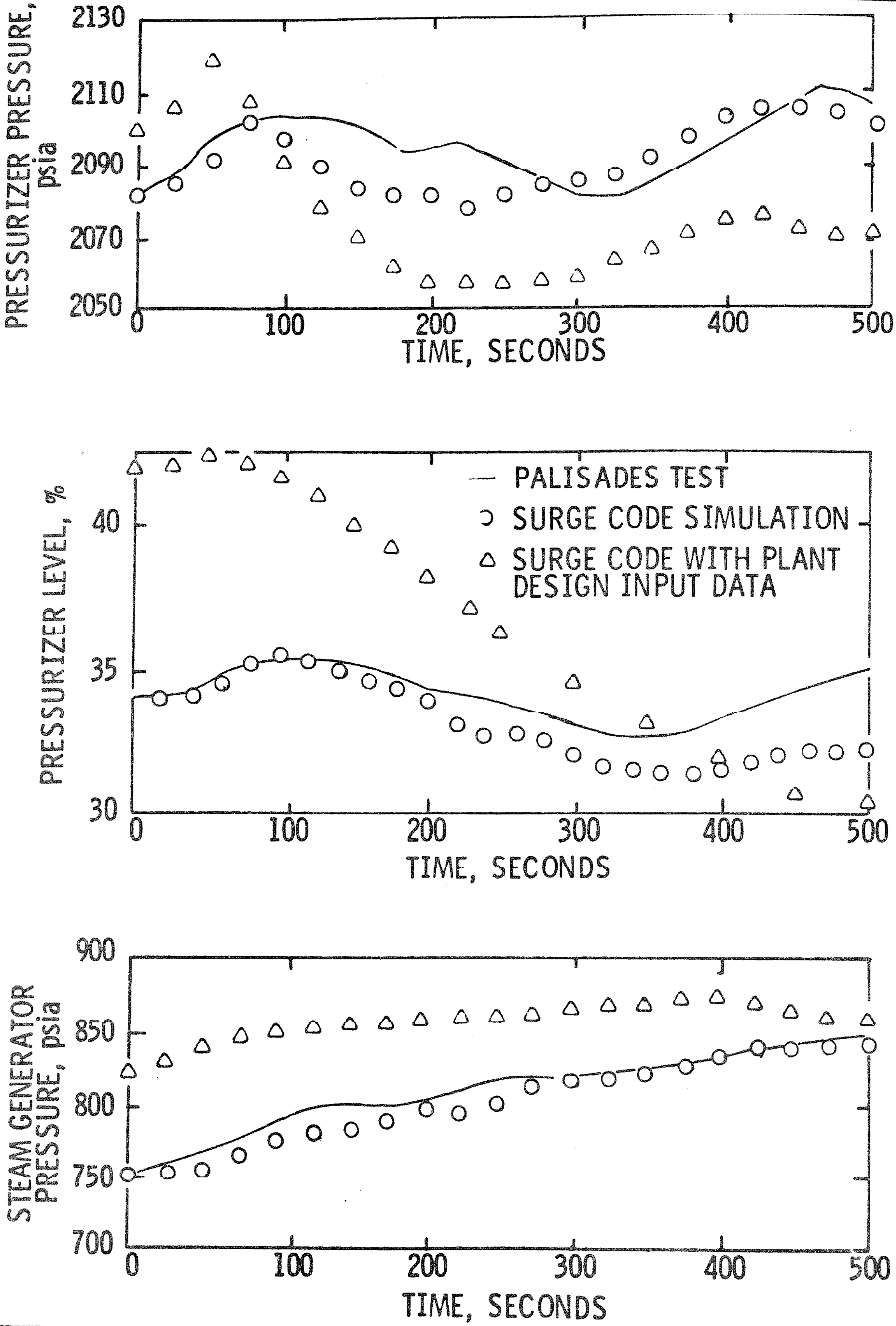

| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | GENERATOR TRIP | Figure 5A - 15 |
|---|---|---|



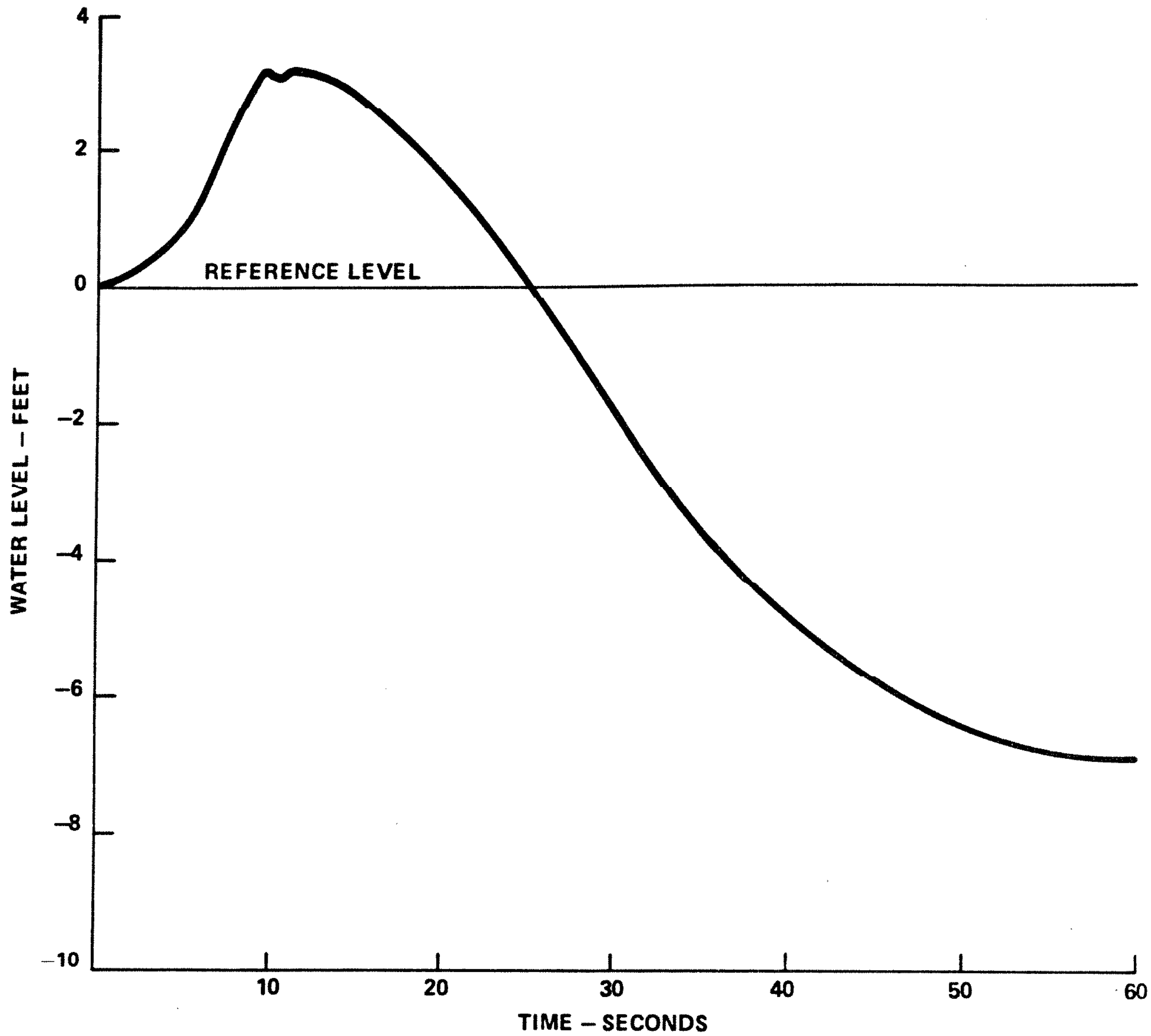

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | GENERATOR TRIP | Figure 5A - 16 |




| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | 5% PER MINUTE POWER RAMP (51% TO 18% POWER) | Figure 5A - 17 |
|---|---|---|



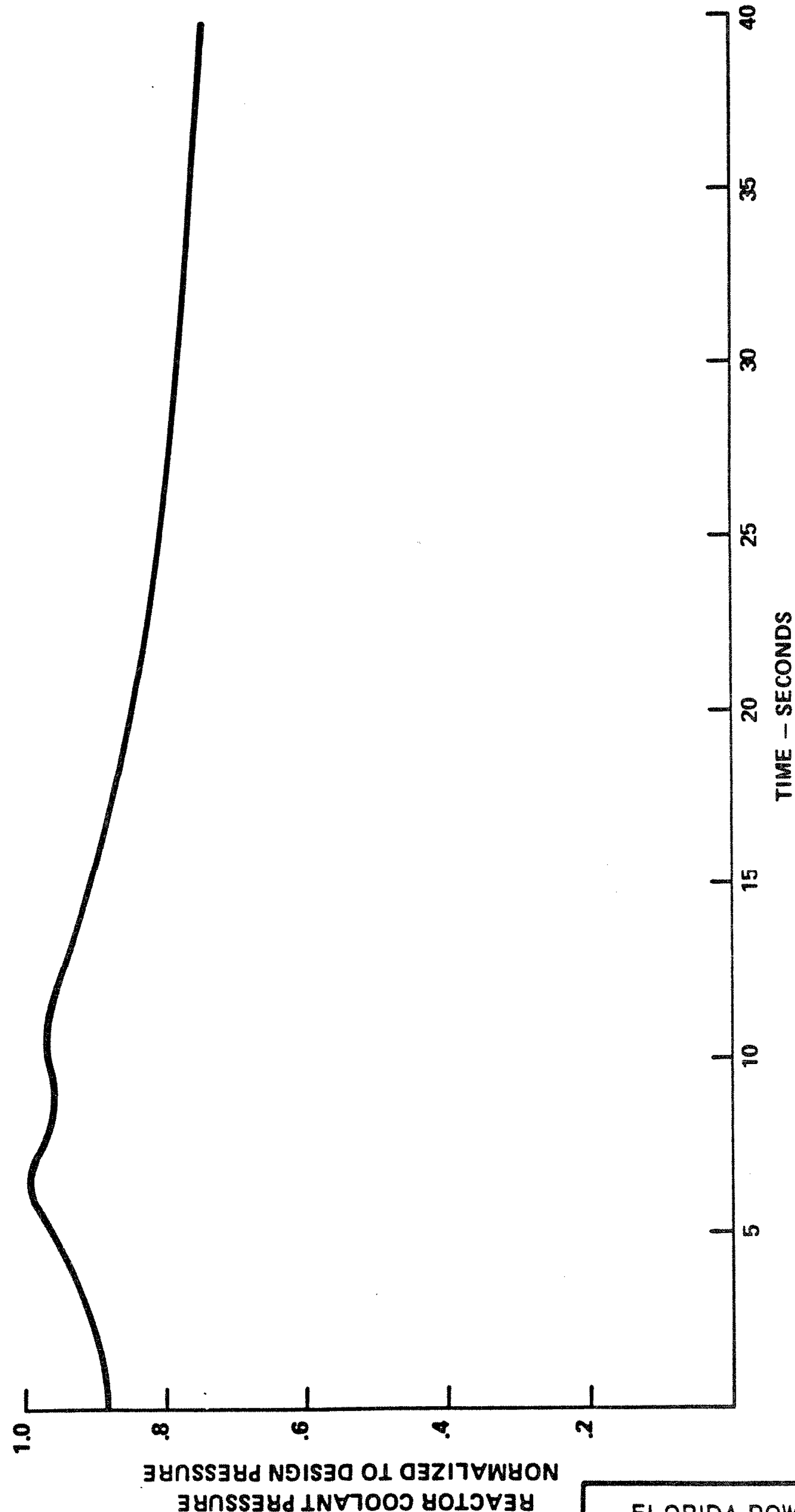

| | | |
|---|---|---|
| FLORIDA POWER & LIGHT CO. St. Lucie Plant Unit 1 | 5% PER MINUTE POWER RAMP (51% TO 18% POWER) | Figure 5A - 18 |




FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

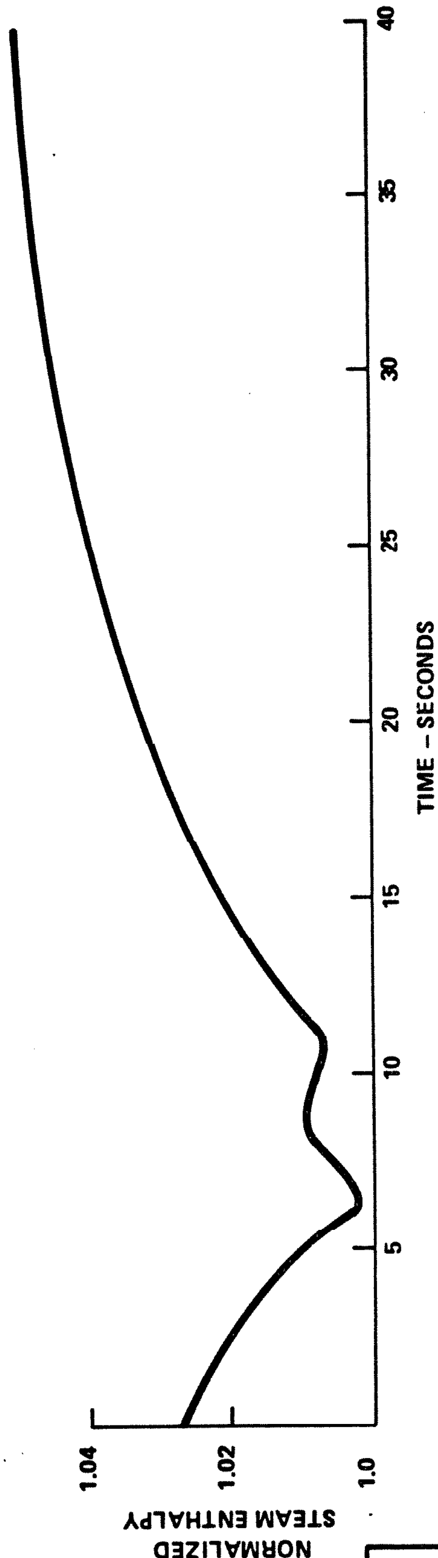
LEVEL VS. TIME DURING LOSS OF LOAD WITH DELAYED REACTOR TRIP

**FIGURE** 5A-19




FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

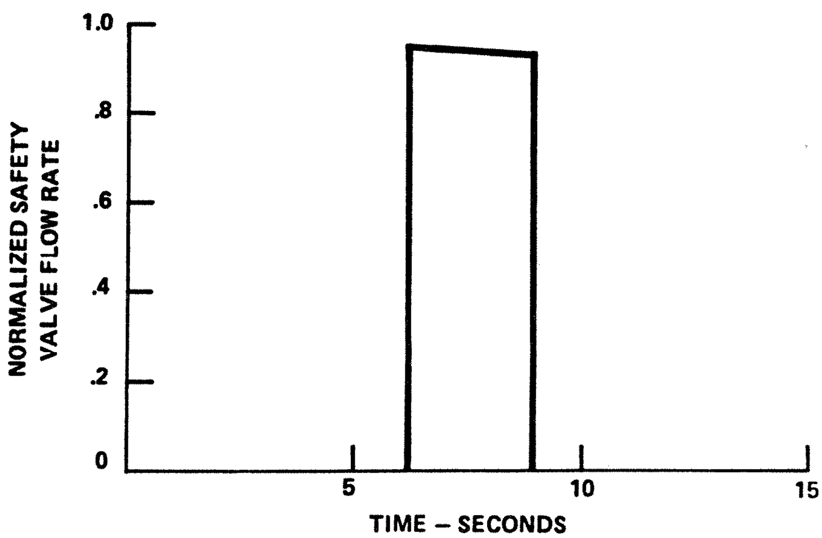
NORMALIZED PRESSURE VS. TIME
DURING LOSS OF LOAD WITH
DELAYED REACTOR TRIP
FIGURE 5A-20




FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

NORMALIZED STEAM ENTHALPY DURING LOSS OF LOAD WITH DELAYED REACTOR TRIP

**FIGURE 5A-21**




FLORIDA POWER & LIGHT COMPANY
**ST. LUCIE PLANT UNIT 1**

NORMALIZED SAFETY VALVE FLOW RATE VS. TIME DURING LOSS OF LOAD WITH DELAYED REACTOR TRIP
**FIGURE 5A-22**

APPENDIX 5B

Low Temperature

Reactor Coolant System

Overpressure Mitigation

For

St. Lucie Unit 1

## 1.0 LOW TEMPERATURE OVERPRESSURE PROTECTION

The primary objective of low temperature overpressure protection (LTOP) systems, also referred to as the overpressure mitigation system (OMS), is to preclude violation of applicable Technical Specification P-T limits during startup and shutdown conditions. These P-T limits are usually applicable to a finite time period defined in effective full power years (EFPY), number of cycles, etc. and are based upon the irradiation damage prediction by the end of period. Accordingly, each time new P-T limits are to become effective, the LTOP system needs to be re-analyzed and modified, if necessary, to continue its function.

A typical LTOP system includes pressure relieving devices and a number of administrative and operational controls. At St. Lucie Unit 1, LTOP is currently provided by two PORVs made by Dresser Industries. The PORVs (Tag Nos. V1402 and V1404) are pilot-operated relief valves with a bore diameter of 1-5/16 inches. Each PORV has the same double LTOP setpoints of 350/530 psia which, in combination with certain other limiting conditions for operation contained in Technical Specifications, comprise the St. Lucie Unit 1 LTOP system. The temperatures at which the LTOP system is enabled are determined in accordance with a definition contained in the Standard Review Plan 5.2.2 (Reference 1).

The current P-T limits and LTOP analysis are based upon the Westinghouse analysis to support the uprating of the unit to a nominal power level of 3020 MWt. The reactor pressure vessel beltline P-T limits are based upon the irradiation damage prediction methods of Regulatory Guide 1.99, Revision 2 (Reference 2). This methodology was used to calculate the limiting material adjusted reference temperatures for St. Lucie Unit 1 utilizing fluence values corresponding to 54 effective full power years (EFPY).

Reference 3 includes the analysis methods, inputs and assumptions that make up the P-T limit curves and LTOP requirements contained in the technical specifications for a nominal power level of 3020 MWt.

## 2.0 REFERENCES


1. U.S. Nuclear Regulatory Commission Standard Review Plan (SRP) 5.2.2, "Overpressure Protection," Revision 3, March 2007.

2. Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials," U.S. Nuclear Regulatory Commission, Revision 2, May 1988.

3. WCAP-17197-NP, Revision 1, “St. Lucie Unit 1 RCS Pressure and Temperature Limits and Low-Temperature Overpressure Protection Report for 54 Effective Full Power Years,” January 2012.

# APPENDIX 5C

# ANALYSIS OF NATURAL CIRCULATION COOLDOWN WITHOUT UPPER HEAD VOIDING FOR ST. LUCIE UNIT 1

DECEMBER 1980

NUCLEAR ANALYSIS DEPARTMENT
FLORIDA POWER & LIGHT COMPANY

## INTRODUCTION

An analytical evaluation of natural circulation cooldown to shutdown cooling system entry conditions without formation of voids was performed for the St. Lucie Unit 1 Plant in 1980 (Reference 2). The reactor coolant system pressure must be reduced to 275 psia for shutdown cooling initiation. Consequently to prevent the formation of voids, the upper head fluid must be cooled to a value less than the corresponding saturation temperature of 409.5°F. After that time de-pressurization to shutdown cooling system entry conditions can occur without void formation in the reactor coolant. Hot leg temperature cooldown rates of 30°F/hr. and 50°F/hr. to 325°F were investigated to determine the cooldown time required for the fluid temperature in the reactor vessel upper head to reach shutdown cooling entry conditions without void formation.

## THERMAL HYDRAULIC MODEL

The analysis was performed with a detailed thermal-hydraulic model utilizing the RETRAN (Reference 1) computer code. Specific features of the model include: a detailed nodalization of the upper portion of the reactor vessel including a representation of the reactor vessel walls and internals; a number of automatic control systems including those for charging pumps, the letdown flow control valve and the pressurizer heaters; and a non-equilibrium thermal-hydraulic model for the pressurizer.

## ANALYSIS RESULTS

The 1980 analysis of a St. Lucie Unit 1 natural circulation cooldown from full power for a hot leg temperature cooldown rate of about 30°F/hr. to 325°F demonstrated that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 16.1 hours. The condensate supply required for this cooldown is 218,500 gallons.

The same analysis for a hot leg temperature cooldown rate of about 50°F/hr to 325°F demonstrates that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 14.2 hours. The condensate supply required for this cooldown is 193,000 gallons.

The analysis for a hot leg temperature cooldown rate of about 50°F/hr. to 325°F was repeated using very conservative assumptions regarding fluid mixing in the upper reactor vessel in order to determine a bounding cooldown time for operating guidelines. The results demonstrate that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 25.7 hours. The condensate supply required for this cooldown is 270,500 gallons.

## RECOMMENDATION

The above results show that for a hot leg temperature cooldown rate of 50°F/hr. to 325°F, the upper head fluid can be cooled to shutdown cooling system entry conditions without void formation in approximately 14.2 hours. In order to provide additional conservatism, it is recommended that for natural circulation cooldown to shutdown cooling system entry conditions without void formation, the hot leg temperature cooldown rate be about 50°F/hr. to 325°F followed by a soak at 325°F for 20.4 hours for a total cooldown time of approximately 25.7 hours from cooldown initiation.

## EFFECT OF REPLACEMENT STEAM GENERATORS

The time it takes for the plant to cool down to shutdown, system entry conditions can be affected by the primary systems natural circulation flow rate. Specifically, if the natural circulation flow rate with the replacement steam generators (RSGs) is less than that with the original steam generators (OSGs), the hot leg temperature at any given time would be greater than the analysis value. This could cause a delay in initiating the shutdown cooling system. However, the flow resistance of the RSGs is less than that of the OSGs and the heat transfer capacity of the RSGs is greater than that of the OSGs. These equipment parameter changes support the ability to cool the plant with natural circulation. Were these parameters adversely affected by future S/G tube plugging, natural circulation flow rate and heat transfer can be maintained by increasing the thermal driving head by steaming to reduce secondary side pressure and temperature.

Furthermore, variations in the steam generator heat transfer characteristics will not affect the calculations in this appendix because the calculated cooldown times are limited by reactor vessel upper head fluid cooldown rate. Therefore, the analysis remains valid for St. Lucie 1 with the RSGs.

## EFFECT OF UPRATE TO 3020 MWT

To evaluate the natural circulation capability for the St. Lucie Unit 1 at an uprated power of 3020 MWt, the CENTS computer code was used to simulate the plant response to a loss of offsite power followed by a natural circulation cooldown from hot standby conditions to shutdown cooling system entry conditions. The CENTS code is an NRC approved code that is acceptable for referencing in licensing applications for Combustion Engineering designed pressurized water reactors.

The previously analyzed scenarios were simulated. The resulting total cooldown time and condensate volume required can be compared to the 1980 analysis values.

At an uprated power of 3020 MWt, the simulations demonstrate that the plant can be cooled down to SDC entry conditions using safety grade equipment only while maintaining pressure control (no voids in the RCS) for a loss of offsite power event.

The 3020 MWt uprate at St. Lucie Unit 1 will not adversely impact the natural circulation cooldown capability of the plant for the following reasons:

- The maximum core $\Delta T$ during the 30°F/hr and the 50°F/hr cooldown is lower than the normal full power $\Delta T$ of 53°F.
- The reactor coolant system pressure is reduced to 268 psia for SDC initiation and the upper head fluid is cooled to a value less than the corresponding saturation temperature of 407°F.

This analysis also shows:

- Acceptable results were determined for natural circulation cooling during the hot standby period for expected residual heat rates immediately following reactor shutdown from the 3020 MWt uprate conditions.

- The ADVs are adequate to achieve cooldown to the SDC entry point in a reasonable time period. SDC entry conditions can be achieved in less than 25 hours at a cooldown rate of 30°F/hr and in less than 24 hours at a cooldown rate of 50°F/hr, which includes one (1) hour in hot standby.

The results of the CENTS simulation for the 30°F/hr cooldown show that it will take about 24.8 hours to reduce the Reactor Vessel Upper Head (RVUH) temperature to 409.5°F (saturation temperature corresponding to the SDC entry pressure of 275 psia). The results are presented in Figure 5C-1. The condensate supply required for this cooldown is about 287,000 gallons.

The results of the CENTS simulation for the 50°F/hr cooldown show that it will take about 23.7 hours to reduce the RVUH temperature to 407°F (saturation temperature corresponding to the SDC entry pressure of 268 psia). The results are presented in Figure 5C-2. The condensate supply required for this cooldown is about 291,500 gallons.

REFERENCE:

(1) RETRAN-A Program For One-Dimensional Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, Volumes 1, 2, 3 and 4, EPRI CCM-5, December 1978.

(2) Letter L-80-343, Robert E. Uhrig (FPL) to Mr. Thomas M. Novak (NRC) dated October 17, 1980.

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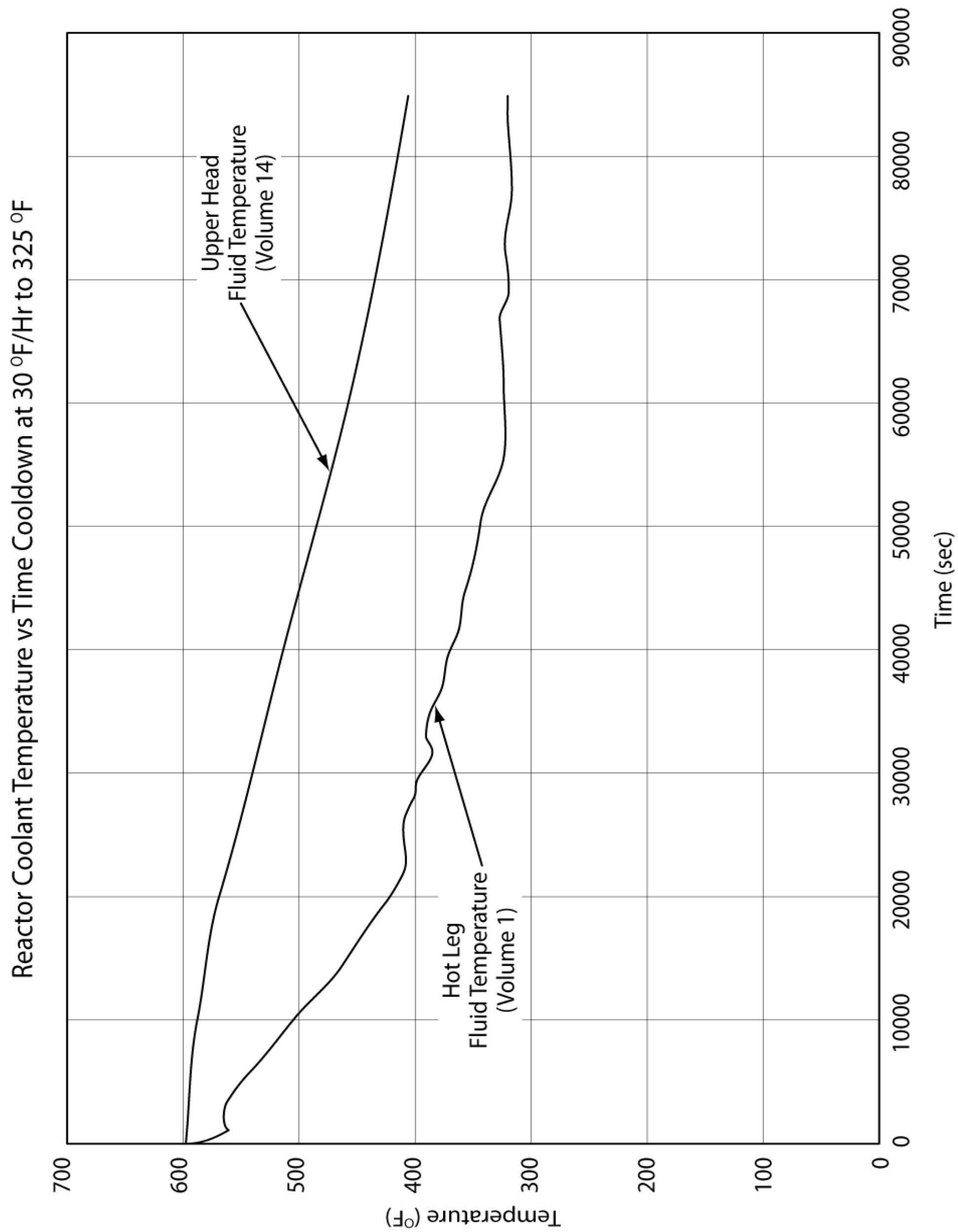
ST. LUCIE PLANT UNIT 1

MODEL VOLUME, JUNCTION
AND CONDUCTOR GEOMETRY

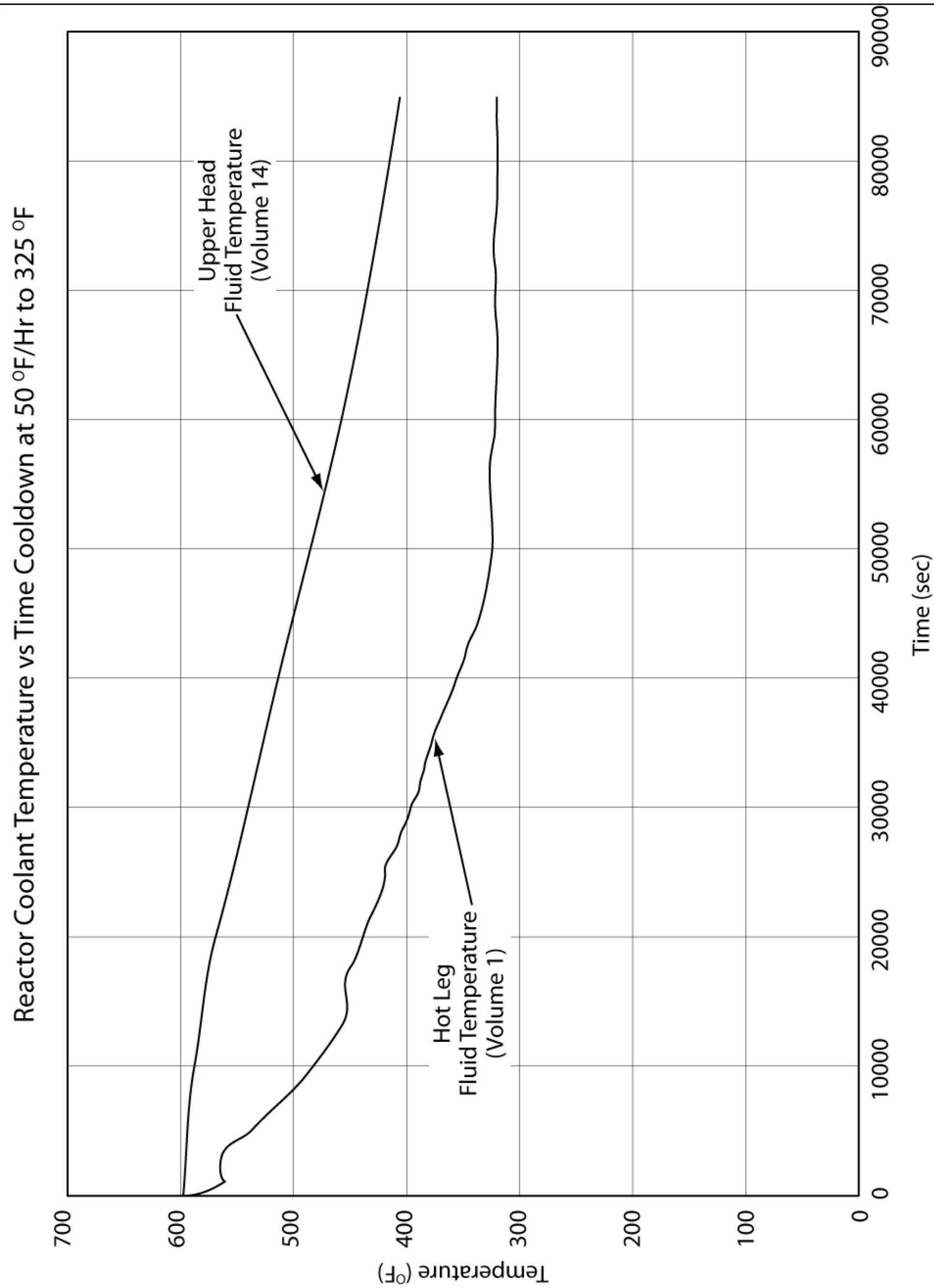
FIGURE 5C-1




FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

REACTOR COOLANT TEMPERATURE VS. TIME
COOLDOWN AT 30°F/HR. TO 325°F

FIGURE 5C-2




FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

REACTOR COOLANT TEMPERATURE VS TIME
COOLDOWN AT 50°F/HR TO 325°F

FIGURE 5C-3