October 1, 2012

L-2012-361
10 CFR 50.59(d)

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555

Re: St. Lucie Unit 1
Docket No. 50-335
Report of 10 CFR 50.59 Plant Changes

Pursuant to 10 CFR 50.59(d)(2), the enclosed report contains a brief description of any changes, tests, and experiments, including a summary of the 50.59 evaluation of each which were made on Unit 1 during the period of June 15, 2010, through April 21,2012. This submittal correlates with the information included in Amendment 25 of the Updated Final Safety Analysis Report to be submitted under separate cover.

Please contact us should there by any questions regarding this information.

Sincerely,

Eric S. Katzman
Licensing Manager
St. Lucie Plant

ESK/tlt

Enclosure

IE47
NRR

ST. LUCIE UNIT 1
DOCKET NUMBER 50-335
CHANGES, TESTS AND EXPERIMENTS
MADE AS ALLOWED BY 10 CFR 50.59
FOR THE PERIOD OF
JUNE 15, 2010 THROUGH APRIL 21, 2012
(60 PAGES INCLUDING COVER)

ST. LUCIE UNIT 1
DOCKET NUMBER 50-335
CHANGES, TESTS AND EXPERIMENTS
MADE AS ALLOWED BY 10 CFR 50.59
FOR THE PERIOD OF
JUNE 15, 2010 THROUGH APRIL 21, 2012

INTRODUCTION

This report is submitted in accordance with 10 CFR 50.59 (d)(2), which requires that:

i) changes in the facility as described in the SAR;
ii) changes in procedures as described in the SAR; and
iii) tests and experiments not described in the SAR

that are conducted without prior Commission approval be reported to the Commission in accordance with 10 CFR 50.90 and 50.4. This report is intended to meet these requirements for the period of June 15, 2010 through April 21, 2012.

This report is typically divided into three (3) sections. First, changes to the facility as described in the Updated Final Safety Analysis Report (UFSAR) performed by a Permanent Modification. Second, changes to the facility/procedures as described in the UFSAR, or tests/experiments not described in the UFSAR, which are not performed by a Permanent Modification. And third, a summary of any Fuel Reload 10 CFR 50.59 evaluation.

Sections 1, 2 and 3 summarize specific 10 CFR 50.59 evaluations that evaluated the specific change(s). Each of these 10 CFR 50.59 evaluations concluded that the change does not require a change to the plant technical specifications, and prior NRC approval is not required.

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SECTION 1

PERMANENT MODIFICATIONS

PERMANENT MODIFICATION EC 235845

10 CFR 50.59 EVALUATION REVISION 0

QUALIFIED SAFETY PARAMETER DISPLAY SYSTEM (QSPDS) REPLACEMENT

Summary:

This modification replaces the St. Lucie Unit 1 Qualified Safety Parameter Display System (QSPDS) with Triconex® triple redundant fault tolerant controllers and replaces the plasma display monitors with new Westinghouse Flat Panel Display (FPD) monitors. The replacement system performs the same functions as the existing system, namely the display of data for Core Exit Thermocouples (CETs), Heated Junction Thermocouples (HJTCs) and Subcooled Margin Monitoring (SMM) for the Inadequate Core Cooling System (ICCS).

The Qualified Safety Parameter Display System has become obsolete, difficult and increasingly expensive to maintain. The system is being replaced as part of an overall Life Cycle Management (LCM) programmed replacement of selected plant monitoring and control systems.

Existing QSPDS equipment located in the cabinets QSPDS A, QSPDS B and Reactor Turbine Generator Boards (RTGBs) 103 and 104 will be replaced. The QSPDS Human-Machine Interface (HMI) is affected by these modifications in two ways. First, the new touchscreen Flat Panel Displays (FPDs) are larger than the current plasma displays and will offer a wider selection of display options. Secondly, an operator interface trackball/keyswitch panel will replace the existing keypads mounted on the RTG Boards.

The existing controllers for the heated junction thermocouples currently installed in the QSPDS cabinets will also be replaced. The new controllers are a Westinghouse design and will be installed in the existing QSPDS cabinets. The location of these controllers within the cabinet are detailed by the Triconex installation drawings.

The existing power sources and cables to the QSPDS cabinets A and B will be re-used. The power source for QSPDS cabinet A is PP-1A and the power source for QSPDS cabinet B is PP-1B. Power Panels 1A and 1B also power the existing QSPDS flat panel displays, modems and power supplies within the RTG board, and will be re-used to power the new Westinghouse PC Node boxes which drive the new FPDs.

The modifications described in this package take place within the Unit 1 Control Room. This location is environmentally mild as

well as being a controlled access area.

The existing Control Room Annunciator tiles J-32 (Channel A) and J-33 (Channel B), "QSPDS INADEQUATE CORE COOLING," will remain active, but will be relabeled. Six additional alarm windows are being added to provide more information for the operators and standardize the alarm windows between Units 1 and 2. Concurrent with annunciator alarm windows, human factors engineered navigation aids are provided on each QSPDS display to assist operators in the determination of the source of the alarm.

The existing redundant and diverse copper power cables between the PP-1A, PP-1B and the Unit 1 QSPDS cabinets and the flat panel displays will be retained. New fiber optic cables will be pulled between the QSPDS cabinet A and RTGB 104 and between QSPDS cabinet B and RTGB 103 to facilitate the use of modern connector and modem technology. As added security against damage, a spare fiber cable will be pulled in each race way. Additional annunciator wiring within the RTGBs is being added to facilitate the addition of new alarms.

The implementation of this modification will be during Modes 5 and 6. Currently, Technical Specifications Limiting Condition for Operation 3.3.3.8, Accident Monitoring Instrumentation, requires a unit shutdown in thirty (30) days if the number of operable channels is less than the total number of channels while in Modes 1, 2, and 3.

PERMANENT MODIFICATION EC 246497

10 CFR 50.59 EVALUATION REVISION 0

EMERGENCY RESPONSE DATA ACQUISITION AND DISPLAY SYSTEM (ERDADS) UNIT 1 REPLACEMENT

Summary:

The existing Emergency Response Data Acquisition and Display System (ERDADS) will be replaced and incorporated as part of the digital Distributed Control System (DCS).

The reason for the change is that the ongoing Life Cycle Management Program (LCMP) calls for the installation of a DCS that will replace most of all existing plant information and control systems. The existing ERDADS is approaching the end of its useful life and typically operates in a degraded condition. The original equipment manufacturer no longer supports the product and spare parts are difficult to obtain.

This modification addresses the modified DCS (ERDADS) hardware, DCS (ERDADS) software, and miscellaneous instrumentation as cited below.

Under this EC, the DCS (ERDADS) satisfies regulatory requirements originating from NUREG-0737, Supplement 1, Safety Parameter Display System (SPDS) Requirements and NUREG-0696, Emergency Response Facility Requirements, Human Factors Specification SPEC-IC-014, NUREG-0700 and NUREG-0711. The system displays provide the Human-Machine Interface to the user in the form of graphic mimics. The graphical mimics will be replicated to support user familiarity.

Modifications will take place in the Control Room and Computer Room. Existing ERDADS cabinets will be modified with new electronics. New workstations are being added. The modifications will comply with NEI 01-01. The PDN (Plant Data Network) provides data links among the DCS (ERDADS) equipment and user workstations and displays. Miscellaneous obsolete computer peripheral devices such as data links, etc., will be replaced with current technology components.

In the Control Room, a new Safety Parameter Display System (SPDS) workstation will be installed in a Control Room Panel. A new flat panel display will provide a continuous SPDS display. A new SPDS 20" Touch Screen LCD Display will replace the old SPDS keyboard. All of the display data from the removed equipment will be available on the new DCS equipment.

The 30 KVA Static Uninterruptible Power Supplies (SUPS) 1C , 1D and Reg. Vital AC are powered during a loss of offsite power by the non-safety 125 VDC batteries 1C and 1D via the non-safety 125 VDC busses 1C and 1D respectively. SUPS 1C and 1D power redundant trains of the ERDADS (SAS) "A" and "B".

After this modification, the DCS/ERDADS for each Unit will be separate and independent.

PERMANENT MODIFICATION EC 246545

10 CFR 50.59 EVALUATION REVISION 2

POWER UPRATE - DEH CONTROL SYSTEM UPGRADE

Summary:

EC 246545 Rev. 2 replaces the digital turbine control system (which is part of plant system No. 22) with a more reliable, self-diagnosing, fault tolerant, and online testable digital system that uses modular components, and redundant signal and trip logic processing. As a part of the change, the auto stop oil system is eliminated and replaced with high pressure oil that is independent of the bearing oil supply system. The replacement DEH system improves protection against a single failure that could prevent a trip when required or cause a trip when not required. Turbine and Generator (stator) temperature monitoring and Moisture Separator Reheater (MSR) startup/shutdown controls are also incorporated into the control system functions. The DEH system (system 22) is a non-nuclear safety (NNS) system which is not designed for operation under the stresses that could be imposed by an operating basis earthquake (OBE). The four redundant safety related pressure switches that are used to sense a turbine trip (as indicated by low emergency trip system hydraulic fluid pressure) for reactor trip logic are not being impacted by the EC scope. The replacement DEH system is provided by Westinghouse (Nuclear Automation Division) and is based on the Emerson Ovation Distributed Control System (DCS) platform customized for use as a turbine control system (TCS).

The EC replaces the mechanical overspeed protection system and overspeed protection controller (OPC) overspeed trips, associated components and auto stop oil system, with (two) independent electronic overspeed trip systems that dump system hydraulic fluid to rapidly close the steam admission valves. These electronic overspeed trips are generated by employing multiple, diverse trip schemes via triple redundant logic channels that include triple redundant passive and active sensing elements (i.e., speed probes). The fault tolerant, diverse trip schemes provide high assurance that an overspeed trip can be produced when potentially damaging overspeed conditions are sensed.

For perspective, the replacement DEH control system is an Emerson Ovation Turbine Control Logic Platform similar to the platform integrated into the AP1000 Advanced Light Water Reactor (ALWR) standard design that was evaluated and accepted by the NRC in NUREG-1793 Supplement 2.

In addition to generic analyses completed by the vendor as supporting documentation for the Ovation platform, St. Lucie application specific Failure Modes and Effects Analysis, Software

Hazards Analysis and Reliability/Fault Tree Analysis were completed to evaluate the acceptability of the DEH Controls Upgrade and to support the conclusion that the software and control system have a low probability of causing hazards, and provides adequate defensive measures in the design to minimize exposure to upsets resulting from individual component failures or unauthorized access. Aspects of the digital upgrade software lifecycle and verification and validation process are described in the Software Lifecycle, Configuration Management and V & V Plan. Also, these evaluations (both qualitatively and quantitatively) support the conclusion that the annual probability of an unsafe overspeed condition post-upgrade remains bounded by the current analyses for the St. Lucie Unit 1 Siemens Power Generation / Westinghouse turbine (with upgraded HP and LP rotors) where semi-annual valve testing is performed. It is also noted that governor valve failures are the dominant contributors to destructive overspeed probability and that individual elements of the electro-hydraulic system (including trip system) have a smaller impact. The general NRC acceptance criteria for turbine missile ejection probability is (not to exceed) 1.0E-05 per year for unfavorably oriented turbines (such as St. Lucie Unit 1). The evaluated annual turbine missile ejection conditional probability for St. Lucie is 2.58E-06 (assuming a 6 month valve test interval).

The specific activity being evaluated is the implementation of a design change that eliminates the mechanical overspeed protection system and replaces it with an electronic overspeed protection system. The mechanical overspeed protection system is one of the two overspeed protection systems explicitly credited in UFSAR Section 10.2.2 (Turbine-Generator) Description, and UFSAR Section 3.5.3.2.b (Selected Missiles, External Missiles) Turbine Missiles for the prevention of missile hazards that could challenge safety-related structures, systems and components (SSCs). Although the OPC overspeed trip is also being replaced, the replacement system is equivalent to the existing OPC overspeed control and trip. The existing electronic Overspeed Protection Control (OPC), consisting of DEH control logic actuating OPC solenoids that drive the Governor and Intercept Valves closed (at a setpoint of 103% rated speed [1854 rpm]) is upgraded with new actuation electronics. Since the replacement DEH system OPC controller function provides more than commensurate single failure protection to preclude an unsafe overspeed condition and performs the same nominal 103% valve closure function as existed previously, the changes associated with these attributes are not included in the scope of this evaluation (and are screened for 10 CFR 50.59 applicability in support of this EC). Only the replacement of the mechanical overspeed, which is explicitly credited in the UFSAR and SRP, with an electronic trip, is being evaluated herein.

The calculated overspeed for St. Lucie Unit 1 following the HP and LP turbine upgrades and thermal uprating is 114.6% based upon full load conditions. The calculated overspeed at the current operating conditions with consideration of the existing rotor train moment of inertia is 115.6%. Therefore, the calculated overspeed will be approximately 1% lower following the HP and LP turbine upgrade and uprating, and as a result, no changes are required to the overspeed trip settings. The overspeed values provided above, are based on a trip setpoint of 111%, and stored energy due to the turbine volumes only.

The Standard Review Plan (NUREG-0800), Section 10.2, Rev. 2, Turbine Generator, provides NRC staff guidance on the reviews of the turbine-generator system to confirm that redundant overspeed protection instrumentation and controls is employed to provide assurance that an overspeed condition above the design overspeed is very unlikely. The review is conducted to provide assurance of conformance to General Design Criterion 4. As a part of the review, the adequacy of the control and overspeed protection system is verified and the review determines the following:

- SSCs function in light of a single failure and will preclude an unsafe turbine overspeed.
- For normal speed-load control the speed governor secures steam flow at 103% of rated turbine speed by closing the control and intercept valves.
- A mechanical overspeed trip device is provided that will actuate the control valves (i.e., governor valves in the St. Lucie application), stop valves (i.e., throttle valves in the St. Lucie application), and intercept valves at 111% of rated steam.

The changes proposed by this EC are evaluated against the PSL Unit 1 UFSAR (facility description) through Amendment 24 and current licensing basis including the guidance contained in NUREG-0800 - the Standard Review Plan (SRP). There are no Technical Specifications associated with the change (reviewed through Amendment 211).

The EC is also evaluated against EPU guidance NRC RS-001, which addresses turbine missiles. The SRP sections and reference version are outlined in RS-001 Rev. 0, PWR sections 2.5.1.2.1, Internally Generated Missiles (with specific review criteria contained in SRP Sections 3.5.1.1 and 3.5.1.2) and 2.5.1.2.2, Turbine Generator (with specific review criteria contained in SRP Section 10.2).

The installation of the DEH replacement system (which is a digital upgrade) will provide two electronic overspeed trips (each using separate sensors with different technology per

redundant set). Therefore, aspects of the digital upgrade are evaluated pursuant to the guidance in RIS 2002-22 and its associated guidance documents (NEI 01-01/EPRT TR-102348 Rev. 1). The replacement overspeed trip design is evaluated relative to the original (mechanical and electronic) overspeed trip design to demonstrate that comparable or improved safety margin is provided by the replacement overspeed trip design. The design is required to provide single failure protection, on-line testability and diverse protection means with circuit independence.

This evaluation documents conformance to the requirements outlined in Criterion 4 (Environmental and Dynamic Effects Design Bases) of Appendix A to 10 CFR 50, General Design Criteria (GDC) for Nuclear Power Plants. GDC 4 requires that:

Structures, systems, and components (SSCs) important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These SSCs shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping and discharging fluids that may result from equipment failure.

Given that St. Lucie Unit 1 is also implementing an Extended Power Uprate, additional (NRC RS-001) EPU criteria is included:

Per Section 2.5.1.2.2, (Turbine Generator):

Turbine overspeed is a hazard explicitly evaluated in the UFSAR (reference Section 3.5.3) due to the potential to generate missiles that could potentially damage safety-related systems, structures and/or components. Since centripetal force varies with the square of the rotational speed, uncontrolled speed increases have the potential to create rapidly increasing stresses that can exceed the yield point or structural integrity limits of the turbine blades, or the connection between turbine blades and the rotor hub (and disc), and thereby generating high energy missiles.

The current EHC system design has overspeed trip redundancy and diversity by employing the following:

- Two parallel OPC solenoid valves to dump governor and interceptor valve emergency trip fluid to force closure of interceptor and governor valves to reduce turbine speed without a full turbine trip (at a setpoint of 103% rated speed [1854 rpm]).
- The mechanical overspeed dumps the auto stop oil to initiate a turbine trip on overspeed setpoint exceedance

(111% rated speed [1998 rpm]); this trip closes the governor, throttle, interceptor and reheat stop valves; as well as the extraction steam non-return valves via a fluid operated air pilot valve (the non-return valves are closed to prevent reverse flow from the extraction steam lines and feedwater heaters). The governor and interceptor valves are closed via the actuation of a diaphragm interface valve (FCV-22-148) via check valve V22147.

- The OPC controller also senses overspeed conditions (111.5% rated speed setpoint) and actuates a dump of the auto stop oil by energizing the 20/AST trip solenoid. Note that the setpoint for this OPC initiated overspeed trip is being lowered to 111% rated speed to be consistent with the Siemens control settings. This change is considered conservative with respect to the existing overspeed trip and has negligible impact on TCS performance.

This EC installs 3 active speed probes (associated with the Operator Automatic/Overspeed Protection Controller (OA/OPC) logic) and 3 passive speed probes (associated with the Emergency Trip System (ETS) controller protection logic. The replacement system also includes 1 each installed spare passive and active probe wired out to the field terminal box that enables on-line replacement of a failed (passive and or active) probe.

Each (in-service) speed probe (sensing element) is hardwired directly to its associated speed detector module (SDM) that provides signal conditioning and simple command logic that compares the process signal to the pre-established setpoint and actuates an integral relay (with a 4 millisecond (ms) response time) that provides the individual channel trip signal upon setpoint exceedance. The simple signal comparison algorithm in the SDM is developed using a simple microcontroller (with a 5 ms update rate). The SDM provides a configurable/adjustable signal comparison - setpoint. The SDM is capable of detecting an open circuit in its associated speed probe wiring. The SDM design also allows the raw speed signal to be "passed through" to the associated redundant system controller for fault-tolerant two-out-of-three (2oo3) trip logic voting. The SDMs and redundant (ETS and OA/OPC) controllers separately and independently sense and command individual channel trips to rapidly actuate a turbine trip signal on overspeed conditions via output relay contacts. Each SDM channel is directly wired to its associated triple redundant trip device circuit for trip voting contribution. The normally-closed contact of the SDM output relay is employed to provide a channel trip signal. Additionally, wiring for the passive probes is routed in separate conduit from the active probes.

The porting (or dumping) of hydraulic fluid is now performed using redundant and (on-line) testable dump manifolds (TDMs). TDMs are designed to rapidly de-pressurize a turbine trip header (with a solenoid response time of 50 ms). Triple redundant solenoids (each channel powered independently, but from the same vital AC power source) are tubed in a valve logic configuration that requires 2oo3 solenoid actuation to produce flow (i.e., actuate a turbine trip). The overspeed protection trip TDMs fail-safe in that a loss of power or open circuit results in a trip.

- The OPC overspeed control (103% rated speed setpoint [1854 rpm]) is performed using energize to trip valves and 125 VDC control power. The process input to this logic is from the triple redundant active speed probes and logic from the redundant OA/OPC controller actuates triple redundant output relays. Each relay's normally open output contact energizes (i.e., closes) to actuate its associated TDM-3 solenoid (OPC-A, OPC-B or OPC-C). The OPC overspeed control dumps fluid from the OPC fluid header that controls the Governor and Intercept valves. The OPC fluid header is isolated from the ETS header by a check valve to preclude operation of the Throttle and Reheat Stop Valves.
- The overspeed protection trip (111% rated speed setpoint [1998 rpm]) is performed using a de-energize to trip 2oo3 solenoid valve logic configuration to dump hydraulic fluid. There are two redundant electronic overspeed trip systems that use separate TDMs, with each TDM actuated by 24VDC power from either the ETS Remote I/O (RIO) cabinet TU002CAB or the OA/OPC RIO cabinet TU001CAB.
    - TDM-1 (de-energize to trip) is powered from TU002CAB. The process input to this logic is from the triple redundant passive speed probes. Each speed probe is connected (i.e., hardwired) to its respective speed detector module (SDM) which is capable of processing a channel trip independently of the redundant ETS controllers. The SDMs use simple microcontroller logic versus programmable logic function blocks used by the ETS controller (a real-time operating system is used in the redundant controllers) based on its internal logic and integral output relay. The speed signal is also passed through to the ETS controller TU102CAB in the Control Room for 2oo3 voting logic processing and actuation of output relays.
    - TDM-2 (de-energize to trip) is powered from TU001CAB. The process input to this logic is from the triple redundant active speed probes. The SDM and redundant control configuration is as described above; however the trip logic is processed by the redundant OA/OPC

controllers in cabinet TU103CAB that actuate separate output relays.

The SDM is capable of effecting a change in state of its respective output relay within 10 ms (nominal). SDM actuation times observed during factory acceptance testing were below 10 milliseconds (~8 ms). The electronic overspeed actuation time via the SDMs is well below the API 670 standard of 40 ms for an electronic overspeed detection system to sense an overspeed event and change the state of its output relay(s). Since no explicit mechanical overspeed trip response time requirements were identified, the API standard provides a comparative value that is used for design of electronic overspeed detection and mitigation systems. The aggregate response time of the SDM configuration to cause a trip via a TDM is concluded to be 60 ms nominal. Although empirical mechanical overspeed trip response time data was not identified, the response time of the trip scheme that replaces the mechanical overspeed trip was evaluated and concluded to be acceptable for the following reasons. The response time of the electronics is well within the industry standard. The response time of the TDM direct acting solenoids compared to the mechanical trip valve (V2203, Overspeed Trip Mechanism Trip) and hydraulically actuated Diaphragm Interface Valve (FCV-22-148) needed to complete the turbine trip in the mechanical overspeed trip configuration is considered conservative based on the valve design and the pressure decay required to effect valve movement. The response time of the mechanical overspeed trip is overshadowed by design of the mechanical overspeed trip system and its historical unreliability compared to the repeatability, fault-tolerant electronic overspeed trip design, with diagnostics, and online test capability. The historical unreliability of the mechanical overspeed trip including large setpoint variability is discussed in EPRI TR-1013461. Additionally, steam admission valve performance is the dominant contributor to the potential of reaching damaging overspeed conditions. The new TCS is determined to be fast enough to effect a turbine trip before exceeding the design overspeed of 120% rated speed. Turbine speeds greater than 120% of rated speed can only be reached due to a total functional failure of the turbine overspeed protection system.

The Ovation network is a robust, fault-tolerant, high-speed, communications network designed for real-time mission critical control applications. The network uses high-speed redundant Ethernet switches. Although noncritical data such as performance status, diagnostics and sequence of events/historical data transmission are on the same network (physical media), the communication design guarantees real-time periodic data transmission without loss, degradation, or delay, even under transient conditions. Data storm control is a design feature of

the Ovation network that provides dedicated bandwidth allocation to critical control tasks. Each input is read on separate I/O cards (each on a separate communication branch in the controller) to eliminate a single point of failure in the I/O hardware. This approach is used for all critical-control and protection-input parameters.

The basic Ovation network design reduces the chances of broadcast storms occurring and anti-virus measures are employed (these measures are validated by the vendor prior to being deployed on a TCS). Peripheral devices and non-Ovation workstations are connected on the network switch via pre-defined ports. These ports are configured with additional safeguards to reduce the likelihood of network disruption from non-critical equipment. Protections against such events are built into the network switches, and specific features to handle such events are designed into the controller. Also, the Westinghouse design philosophy does not rely on the network for the data used in critical control loops. Critical loops are contained within a single controller, or data is shared by some other method (data may be shared via the hardwired inputs between controllers).

- Several watchdog timers (WDTs) are employed in Ovation controllers to verify normal operation and to discriminate the health of the controllers and associated I/O devices.
- Ovation controllers contain a collection of internal tests and diagnostics to verify system health, detect failed I/O modules, and validate data, alarm, and failover, if necessary.
- Ovation algorithms extensively used in the application perform validation checks to the inputs to ensure data validity before using it. Any input that does not pass the check will result in setting the point value to BAD quality. Additionally, on start-up, the Ovation controller performs numerous self-diagnostic checks to verify internal system integrity.
- All data exchanges between components utilize checksums and/or cyclic redundancy-check-based error detection mechanisms. Lost packets are recovered utilizing mechanisms that are inherent in the associated protocol(s).
- If an input or sensor has failed or is providing bad data, the controller's diagnostics and comparison programming algorithms will process the data to determine its quality. These quality propagation algorithms catalogue the data into different categories.
- A failed redundant component can be replaced online.
- The overall Ovation control system is qualified for

electro-magnetic compatibility (EMC) consistent with the guidance in Reg. Guide 1.180 Rev. 1.

- The diversity techniques employed in the TCS are consistent with guidance in NUREG/CR-6303 and NUREG/CR-7007.
- Logical and physical access measures are employed to control unauthorized and authorized access to specific user-defined levels/accounts/roles. The TCS operates on its own self-contained network. Security features are utilized where communication with external devices (e.g., time synchronization) is required.

With implementation of the DEH controls upgrade, a higher degree of fault-tolerance and overspeed trip assurance is achieved by using dual-redundant logic controllers in each logic cabinet and by implementing cross-tripping between logic control cabinets whereby a trip signal processed in one cabinet is also hardwired using (triple redundant) isolated contact outputs to produce a contact logic - voting trip via the other cabinet trip actuation equipment. Therefore, multiple diverse trip paths are employed to provide high assurance that a turbine trip can be achieved especially on overspeed conditions.

PERMANENT MODIFICATION EC 246548

10 CFR 50.59 EVALUATION REVISIONS 1 & 2

ELECTRICAL BUS MARGIN IMPROVEMENT

Summary:

The proposed activities of EC 246548 support implementation of the EPU LAR (L-2010-259) following NRC approval. Consequently, some equipment and system modifications will be necessary to support this goal. EC 246548 will support bus margin improvements necessary due to increased load on the buses caused by other modifications, which are required for EPU conditions. These activities:

- Add a Safety Injection Actuation Signal (SIAS) trip of non-essential load contactors on Safety Related (SR) 480 V Motor Control Centers (MCC) 1A5, 1A6, 1B5, 1B6
- Replace Current Limiting Reactors (CLR) at SR 480 V Switchgears 1A2 and 1B2
- Repower Reactor Auxiliary Building (RAB) main supply fans HVS-4A and HVS-4B from SR 480 V MCCs 1A5 and 1B5 to SR 480 V switchgears 1A2 and 1B2
- Add a SIAS trip of feedwater pumps 1A and 1B on NNS 6.9 kV switchgear 1A1 and 1B1 and heater drain pumps 1A and 1B on 4.16 kV switchgear 1A2 and 1B2
- Add a SIAS trip of Main Transformers 1A and 1B coolers on non-nuclear safety (NNS) 480 V switchgear 1A1 and 1B1
- Add a SIAS trip of the Generator Main Leads Fans 1A and 1B (Isophase bus cooling fans) on NNS 480 V switchgears 1A1 and 1B1
- De-energize the following equipment during a SIAS event:
    - Reactor Cavity Sump Pump 1A/1B
    - 120/208 VAC Lighting Panels LP-110 / LP-112 / LP-113 / LP-114 / LP-115 / LP-117 / LP-125
    - 480V Power Receptacles 48 / 50 / 51 / 53 / 57 / 58 / 59 / 60 / 61 / 62 / 63 / 64 / 65 / 66 / 67 / 68 / 69 / 70 / 145 / 146
    - Containment Instrument Air Compressors 1A / 1B
    - Decontamination Room Fan HVE-36
    - RAB Switchgear Room Hoist
    - Office and Classroom Heating Coils EHC-1 / EHC-2
    - Reactor Transfer Machine Console Disconnect Switch DS-M
    - CEA Drive MG Set Hoist
    - Refueling Machine Pool End Junction Box
    - RCB Maintenance Hatch Monorail Hoist
    - Boric Acid Batching Tank Heater
    - Vacuum Relief Valves Hoist
    - RCB Elevator

- Repower Hot Shutdown Control Panel (HSCP) room fans, HVS-9 and its damper and HVE-35, from 120/208 VAC PP-121, Circuit #12, on the Non-Essential section of MCC 1B6 to 120/208 VAC PP-102A on an Essential section of MCC 1B6
- Re-uses existing and adds new cables through conduit and cable trays
- Revises equipment required for hot or cold shutdown operations listed on the Appendix R Essential Equipment List (drawing 8770-B-049)
- Modifies the operation of Associated Circuits in the Safe Shutdown Analysis

Also, the existing voltage transient response from calculation PSL-1-FJE-90-0026, Rev. 6, "St. Lucie Unit 1 Short Circuit, Voltage Drop, and PSB-1 Analysis Calculations," shows that the Design Basis Accident (DBA) event, Mode 1 with SIAS and 230 kV minimum switchyard voltage, results in a voltage margin of less than 1% at SR 480 V switchgear 1A2 and 1B2.

The Degraded Voltage + SIAS maximum pickup voltage limit is 423.0 V (88.125% of 480 V). The minimum actuation time of the Degraded Voltage + SIAS relays is 7.0 seconds. At 6.5 seconds (0.5 second margin), the calculated recovery steady state voltage (worst case) is 425.3 V (88.60% of 480 V) on SR 480 V switchgear 1A2 and 427.7 V (89.11% of 480 V) on SR 480 V switchgear 1B2. There is less than 1% voltage separating the actuation of the Degraded Voltage + SIAS relaying from the calculated voltage at 7.0 seconds into the transient prior to the EPU modifications.

The Screening for EC 246548 resulted in four activities screening in. These are summarized below and are the subject of the 50.59 Evaluation.

- Impact on Class IE Batteries - Electrical loads on the Class 1E Batteries increase through the addition of the relays for SIAS trips, control circuits for RAB main supply fans HVS-4A and HVS-4B.
- Impact on 480V MCC - Repower the HSCP fans HVS-9 and its damper and HVE-35 loads from the Non-Essential section of MCC 1B6 to the Essential section of MCC 1B6, which will increase the electrical load on MCC 1B6.
- Seismic Interaction - The installation of four new Agastat relays create potentially adverse seismic loading issues that are currently being addressed.
- Impact on ESFAS - A spurious SIAS-initiated isolation of the main feedwater pumps introduces the possibility of causing a reactor trip.
- Impact to Operating Procedures - The addition of new SIAS trip signals will change how the plant responds to a SIAS, adding steps during recovery and start up from the event that

generated the SIAS. Also, in certain scenarios, the modifications reduce the amount of defense-in-depth equipment that would be available to the Operations staff without having to take restorative actions.

Impact on Class IE Batteries

Repowering the RAB main supply fans HVS-4A and HVS-4B from the SR 480 V MCCs to the SR 480 V switchgear does not have any effect on the EDG loading sequence. Fans HVS-4A and HVS-4B will remain on load block 7 with a timing sequence of 18 seconds (UFSAR, Table 8.3-2).

The batteries will be impacted by the relays added for SIAS trips and the control circuits for fans HVS-4A and HVS-4B. There will be an additional load of 0.265 A on each battery during SIAS load conditions and 0.202 A during SBO load conditions. The analysis in EC 246548, Attachment 14, shows the additional loads are acceptable and remain within the rating and load sequencing of the 125 VDC battery chargers that is input to PSL-1-F-J-E-90-0017, Rev. 3, "Battery Chargers 1A, 1AA, 1B, 1BB Kilowatt Input Demand," that is, in turn, an input to PSL-1-F-J-E-90-0013, Rev. 6, "St Lucie Unit 1 Emergency Diesel Generator 1A and 1B Electrical Loads." There is no impact on these two calculations and no impact on analyzed EDG fuel oil consumption demand documented in PSL-1FSM-09-025, Rev. 0, "Emergency Diesel Generator Fuel Oil Supply St. Lucie Unit 1."

Impact on 480V MCC

The existing CLRs are replaced with CLRs of lower impedance. The replacement CLRs are designed to be a direct replacement for the existing CLRs. No new failure modes are introduced by this modification.

Electrical loads on the Essential 480V MCC 1B6 increase as a result of the proposed activities. The ETAP reanalysis that is, in turn, an input to PSL-1-F-J-E-90-0013, Rev. 6, "St Lucie Unit 1 Emergency Diesel Generator 1A and 1B Electrical Loads," show that loss of bus margin upon SIAS is insignificant. There is no impact on these two calculations and no impact on analyzed EDG fuel oil consumption demand documented in PSL-1FSM-09-025, Rev. 0, "Emergency Diesel Generator Fuel Oil Supply St. Lucie Unit 1."

Seismic Interaction

RTGB-102

Two new ABB MG-6 relays (94AZ/1957 and 94BZ/1957) will be mounted in RTGB-102 using (2) ¼"-20 screws. Relay 94BZ/1957 will be

mounted to a 3/16″ bent plate which will be mounted to RTGB-102. The weight of each relay is approximately 5 lbs, and the weight of the bent plate is approximately 4 lbs, for a total of 14 lbs to be added to RTGB-102. Comparing the addition of 14 lbs to the weight of RTGB-102, it can be concluded that the addition of the two relays and the bent plate will have an insignificant impact on the natural frequencies and the structural capacity of RTGB-102. Therefore the existing RTGB-102 is acceptable for the mounting of the 2 ABB MG-6 relays.

The two ABB MG-6 relays are NNS; however, there is existing safety-related (SR) equipment mounted in RGTB-102; therefore the mounting of the two ABB MG-6 relays and bent bracket will be seismic II/I. Per STD-C-004 (Pg. 1118 through 1132), the maximum horizontal and vertical accelerations for 2% damping is 1.7g and 1.2g, respectively. Therefore the horizontal seismic loading on each relay is 1.7g x 5 lb = 8.5 lbs and, the vertical seismic loading including self weight of the relay is (1+1.2)g x 5 lb = 11 lbs. Per the relay configuration and installation details, the maximum dimension of the relays are 5.438″ (W) x 5.563″ (D) x 7.438″ (H) and the spacing of the mounting screws is 4.75″. Based on the above dimensions, screw spacing and the seismic loadings the tension and shear loads in the screws are judged to be insignificant compared to the allowable tension load of 0.032 in^2 x 20 ksi = 640 lbs and the allowable shear load of 0.032 in^2 x 10 ksi = 320 lbs (ASTM A307, AISC 9th Edition) of the (2) ¼″-20 screws, therefore are acceptable. The 3/16″x8 3/8″ x 0′-11″ bracket is secured to the side channel with (2) ¼″-20 A307 bolts with spring nuts spaced 9″. The horizontal and vertical seismic loads due to the relay and bracket are 1.7g x (5 lbs+4 lbs) = 15.3 lbs and (1+1.2) g x (5 lbs+4 lbs) = 19.8 lbs. Based on the above loads and mounting configuration, the bending stress in the bent plate (bracket) is judged to be insignificant compared to the allowable bending stress of 0.75 x 36 ksi = 27 ksi (ASTM A36, AISC 9th Edition), and is acceptable. The shear and tension forces in the (2) ¼″-20 bolts are judged to be significantly less than the allowable shear and tension loads calculated for (2) ¼″-20 screws previously, and are acceptable.

The thickness of the RTGB-102 plate to which relay 94AZ/1957 is to be mounted, is approximately ¼″ per walkdown. The thickness of the bracket to which relay 94BZ/1957 is mounted to is 3/16″. Per Pg. 2 of Appendix D of Spec-M-004, the basic dimension for ¼″-20 screws (class 1A/B, worst one) are: $D_{s.min}$ = 0.2367 in, $E_{n.max}$ = 0.2248 in, As = 0.0318 in^2, Sst = 60 ksi (ultimate tensile strength of ASTM A307 for screws, conservative), Snt = 58 ksi (ultimate tensile strength of RTGB-102 mounting plate ASTM A36, conservative), n = 20 threads per inch Per Eq. (1) on Pgs. 1 & 2 of Appendix C of SPEC-M-004 the minimum required length of engagement is calculated as follows: Le = (Sst 2 As)/{Snt 3.1416

$n\ D_{s.min}\ [1/(2n) + 0.57735\ (D_{s.min} - E_{n.max})]\} = 0.139$ in which is less than the RGTB mounting plate thickness of 0.25" and the bracket thickness of 0.1875". Therefore, the threads of the screw and the holes in the RTGB-102 mounting plate and bracket will not be stripped. Therefore the mounting of the new ABB relays (Type MG-6) is acceptable.

RTGB-101 / RTGB-102 / RTGB-106

Diodes and fuses are classified as "seismic insensitive" in Standard STD-C-009, "Seismic Technical Evaluation - Replacement Items and New Designs," as it is (a) of negligible mass and does not affect the dynamic properties of the host, and (b) performs a passive safety related function (i.e., does not change state). The suppression diodes installed across the coils of the SIAS relays have a negligible increase in weight (2.73 grams) and therefore do not affect the dynamics of the relays. Fuses, fuseblocks and diodes are solid passive elements which do not change state.

These devices and the seismically qualified new relays, breakers, and CLRs will be installed in an envelope containing other seismically qualified or seismic II/I devices and, as such, no seismic interaction with non-seismically qualified SSCs is introduced.

Impact on Engineered Safety Features Actuation Signal

The SIAS function is a part of ESFAS, which is safety related. The SIAS function is not affected by the addition of Agastat EGPD isolation relays, which maintain electrical separation from NNS circuits.

Because of the effect on the plant operation by the addition of the SIAS trip signals in operational components such as Feedwater Pumps, these trips have been designed as energize-to-trip in the component control circuit. The energize-to-trip design ensures stable plant operation and helps to prevent a transient caused by a single spurious relay action.

Impact to Operating Procedures

The addition of new SIAS trip signals will change how the plant responds to a SIAS only event, including the loss of the feedwater pumps. These effects have no impact on equipment relied upon for safe shutdown, accident mitigation, or fission product barrier integrity. The effects would be added steps for emergency operating procedures used during recovery and start up from the event that generated the SIAS.

- Procedure 1-EOP-99, "Appendices / Figures / Tables / Data Sheets," and 1-AOP-09.04, "Feedwater, Condensate, and Heater Drain Pump Abnormal Operations," will be revised for the addition of SIAS trips on Feedwater Pumps 1A and 1B and Heater Drain Pumps 1A and 1B.
- Procedure 1-ONP-100.01, "Response to Fire," will be revised to show HVS-4A and HVS-4B repowered from new breakers.
- Procedure 1-AOP-69.01, "Inadvertent ESFAS Actuation," will be revised to add steps to open MV-18-1 due to loss of Containment Instrument Air Compressor 1A.

These procedures will undergo minor change to reflect new restorative instructions after SIAS. A Human Factors evaluation in the EC concluded that the changes do not have an impact on nuclear safety under pre-EPU or EPU operating conditions.

Summary

The additional margin provided for the 480V buses to reach the degraded grid voltage setpoint helps to prevent an electrical transient from occurring, i.e., transfer of key safety components to diesel power. The addition of trip signals initiated by SIAS will change how the plant responds to a SIAS only event. These effects have no impact on equipment relied upon for safe shutdown, accident mitigation, or fission product barrier integrity.

There are no adverse effects on plant safety or operation. The effects of SIAS changes in this modification are bounded by Design Basis Accident (DBA) Loss of Offsite Power (LOOP) accident analyses. Repowering the HVS-4A/4B fans and replacement of the CLRs do not have any adverse affects on plant safety or operation. This modification introduces no new failure modes that could impact nuclear safety. No interaction with accident mitigation SSCs is introduced and no risk is posed to fission product barriers or other defense in depth design features of the plant.

PERMANENT MODIFICATION EC 246550

10 CFR 50.59 EVALUATION REVISIONS 1 & 2

UNIT 1 HEATER DRAIN / MSR / FWH DIGITAL LEVEL CONTROLS UPGRADE

Summary:

EC 246550 implements activities that prepare the plant for operation at Extended Power Uprate (EPU) conditions, as described in St. Lucie Unit 1 EPU LAR (L-2010-259). Specifically, the activities associated with EC 246550 replace pneumatic level control equipment with digital level control equipment for the:

- Moisture Separator Reheaters (MSR)
- High Pressure Feedwater Heaters (HPFWH)
- Drain Collectors

This activity is planned for SL1-24 in addition to other associated ECs that are identified in EC 246550. All physical modifications will be performed during the SL1-24 outage. The level control system will be fully functional for the pre-EPU period, defined as the interim operating period, as well as for EPU conditions. The level controller loop tuning constants may need adjustment at EPU conditions as required.

No aspects of EC 246550 are dependent upon NRC approval of the EPU LAR.

Section 5.2.2.2 of the, "FPL Nuclear Engineering Guidance Document for Performing 10 CFR 50.59 Evaluations," provides the following guidance:

- Procedure changes that fundamentally alter the existing means of performing or controlling design functions should be conservatively treated as adverse and should be evaluated under 10 CFR 50.59. Such changes include replacement of automatic action by manual action (or vice versa), analog to digital upgrades, changing a valve from "locked closed" to "administratively closed," and similar changes.

Based upon the above guidance, Question 3 in the 50.59 Screening regarding, "…a change to a procedure that adversely affects how UFSAR described SCC design functions are performed or controlled" is checked YES, thus requiring this Evaluation to be performed.

The 50.59 Screening Process, which included a review of the Design Change Checklist and a failure modes and effects analysis (FMEA), identified a proposed activity requiring a 50.59

Evaluation. An evaluation of the proposed activities produced the following conclusions:

FMEA

The proposed activity uses new control systems technology that introduces new failure modes and effects. Foundation Fieldbus communications Control In Field (CIF) technology is being introduced to replace the existing pneumatic level controllers, Guided Wave Radar technology is being introduced to measure vessel condensate levels, and Fieldbus capable Digital Valve Controllers are being installed to replace pneumatic valve positioners. The replacement instruments and respective bridles introduce several new possible failure modes. The most notable new failure modes are communications failures and electronic device failures (including loss of power). For each of the new device failure modes, a backup system is available to limit the worst case effects to a reduction in plant operating efficiency.

Therefore, the proposed activity is considered neutral to nuclear safety under the EPU configuration, and a net benefit under the current plant configuration.

- Cyber Security Program - The Heater Drain Fieldbus control system is being integrated into the PI Data Historian network. As a result, this new control system will take advantage of the security measures that have been built into the PI Network. These measures include internal and external firewalls. The new Fieldbus equipment will communicate with the existing PI Historian using the new Fieldbus Interface Modules (FIMs) added as a result of this EC via the Plant Data Network (PDN). The equipment to be added by this EC are not critical digital devices within the scope of the cyber security program. The modification has been reviewed for cyber security considerations and found acceptable. Therefore, the proposed activity is considered neutral to nuclear safety under the current plant and EPU configurations.
- Human Factors - The operators will have newly available data and control functionality available at the HMI screen which is being installed inside the MSR/FW Heater Drain Control Panel. Local manual control of the level control valves will now be available through the HMI screen. Additionally, operators will have continuously recorded data available via the site data historian (PI). The availability of these new control and operator functions represents an improvement over current conditions. The availability of historical data will offer the opportunity to trend and analyze operating conditions that were previously unavailable. This

will provide an enhancement to the current condition and also represents an improvement. Therefore, the proposed activity is considered neutral to nuclear safety under the current plant and EPU configurations.

- Instrument Setpoints - The proposed activity revises level switch setpoints for the replacement MSRs and HP FWHs. New setpoints for alarms and the digital valve controllers are required because higher capacity equipment for the Heater Drain and Vents system is being installed in anticipation of operation at EPU conditions. The Drain Collector vessels will not be changed for EPU. The setpoints associated with Drain Collector high levels will not change. These setpoint changes have been reviewed and approved by Operations. Therefore, the proposed activity is considered neutral to nuclear safety under the current plant and EPU configurations.
- Electromagnetic and Radio-Frequency Interference, Surge or Electromagnetic Discharge - The new electronic equipment being introduced as a result of this plant modification has been tested and certified to be in compliance with International Electrotechnical Commission (IEC) industry standards for susceptibility to EMI/RFI.
    - The Fisher DVC6200F valve positioners have been qualified to IEC61326-1 (First Edition), "Electrical equipment for measurement, control and laboratory use - EMC requirements - Part 1: General Requirements," and meets IEC61000-4-2, -3, -4, -5, -6, and -8 Electromagnetic compatibility (EMC) standards.
    - The Magnetrol Model 705 Series Guided Wave Radar Instruments have been qualified for both emissions compatibility as well as immunity in accordance with the Electromagnetic compatibility (EMC) IEC61000-Part 6-2: Immunity for industrial environments and Electromagnetic compatibility (EMC) IEC61000-Part 6-4: Emission standard for industrial environments, and meets IEC61000-4-2, -3, -4, -5, and -6 standards.
    - The Proface AGP3600-T1-D24 new HMI screen being added has been tested to the IEC61000-4-2 Electromagnetic compatibility standard.

PERMANENT MODIFICATION EC 246552

10 CFR 50.59 EVALUATION REVISION 2

UNIT 1 LEADING EDGE FLOW METER (LEFM) - MEASUREMENT UNCERTAINTY RECAPTURE (MUR)

Summary:

EC 246552 is limited to installing Leading Edge Flow Meter (LEFM) System components and does not result in connection to the plant's Distributed Control System (DCS). Thus, once installed, the LEFM will remain disconnected from other plant systems and will not provide Control Room operators with actionable feedwater flow information.

The LEFM is a highly sophisticated volumetric FW flow-rate measurement system that, when operational and connected to the DCS, supports determination of secondary calorimetric thermal power with an accuracy of approximately ± 0.3% of rated thermal power (RTP) when PSL Unit 1 is operating between 0% RTP and 100% RTP. The LEFM System includes two metering sections (one on each FW stream) welded into the main FW piping, four transmitter enclosures locally mounted near the LEFM metering sections, two CPU enclosures wall mounted in the Control Room, and four pressure transmitters mounted on the same racks as the transmitter enclosures.

EC 246552 provides the design details necessary for installing the new LEFM System as part of a Measurement Uncertainty Recapture (MUR) effort for the Extended Power Uprate (EPU) at St. Lucie Nuclear Power Plant (PSL) Unit 1 Station. The scope of EC 246552 includes:

- Installation of LEFM 1A/1B metering sections in feedwater (FW) piping
- Installation of power supply cabling for transmitters and Control Room central processing units (CPUs)
- LEFM communication media provisions for integration with existing systems
- Mounting of local transmitter enclosures
- Installation of pressure transmitters and connection of resistance temperature detectors (RTDs) for LEFM flow calculations
- Installation of raceway, new cables, and data cabling to instrument racks and the Control Room
- Installation of LEFM CPU cabinets in the Control Room
- Reroute of secondary wet layup piping to accommodate access

area to LEFM System

The Screening performed for EC 246552 resulted in the following Phase 1 activities Screening in. These are summarized below and are the subject of the 50.59 Evaluation.

The LEFM System is a new system and is not described in the current UFSAR. However, based on a UFSAR review of SSCs impacted by LEFM installation, the 50.59 Screen process identified several adverse effects, including:

- Seismic II/I interactions for mounting the CPUs in the Control Room
- Addition of heat load to the Control Room during Station Blackout conditions

The UFSAR (PSL Unit 1 UFSAR Amendment 24) was reviewed to determine for the adverse effects from LEFM installation noted above, impacts to the Current Licensing Basis (CLB) design basis functions, design functions that support design based functions, and design functions that could initiate transients or accidents.

With respect to Seismic II/I, per Unit 1 UFSAR Section 3.1.2 General Design Criterion 2, Design Bases For Protection Against Natural Phenomena:

- Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes ... without loss of capability to perform their safety functions.... Structures, systems and components vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including the DBE.

With respect to Control Room (CR) ventilation and heat load, per UFSAR Section 9.4.1.2.2, Emergency Operation, in response to an outstanding NRC component design basis inspection (CDBI - September 28, 2007) issue, an analysis was performed to determine both personnel habitability and equipment operability in the CR during a station blackout (SBO) event:

- Until the SBO cross-tie is completed (at 25.3 minutes after SBO occurs) none of the three CR AC units will be operating. After 25.3 minutes one AC unit will be energized. In this scenario the maximum probable ambient temperature is 94.4 °F, which ensures that the Control Room remains habitable, and all safe shutdown equipment in it remains operable.

PERMANENT MODIFICATION EC 246554

10 CFR 50.59 EVALUATION REVISIONS 1 & 3

LOW PRESSURE (LP) TURBINE ROTOR REPLACEMENT

Summary:

One high pressure turbine element and two low pressure turbine elements convert thermal energy of steam into kinetic energy in the form of the rotating torque on the shaft. The shafts of the high pressure and two low pressure turbines are coupled to the shaft of the main electrical generator.

The low pressure turbines receive low pressure steam from the moisture separator reheaters via crossover piping connected to the inlet connection of the inner casing. The low pressure steam path consists of the inner casings with stationary blades, the rotors with blades attached, and the outer casings that house the inner casings and rotating assemblies.

The turbine bearing lift oil system provides high pressure lube oil to the bottom of the rotor shafts to lift the shafts off the bearings to prevent metal to metal contact during low rotational speeds.

St. Lucie Nuclear Power Plant - Unit 1 will implement a Nuclear Steam Supply System (NSSS) power uprate which will increase the licensed NSSS power from nominally 2714 MW_t to 3034 MW_t. During the SL1-24 outage, the entire turbine-generator train is to be upgraded which involves the high pressure (HP) turbine rotor replacement, the low pressure (LP) turbine rotor replacement and the generator rotor replacement. The increased NSSS thermal power will result in a flow increase in the steam path through the HP and LP turbines which will result in an increased output of the generator from the existing 850 MW_e to 1080 MW_e as described in EC 246457. The existing LP turbine rotors reached their maximum steam flow capability during the stretch power uprate implemented in the early 1980s. Torsional vibration equipment was added to Unit 1 as the results of the Unit 2 torsional vibration testing proved beneficial. Due to the increased weight of the replacement LP rotors, the existing 15 HP bearing oil lift pump motor must be replaced with a 20 HP motor to provide the proper lift pressure. During SL2-19 outage of Unit 2, a torsional vibration test conducted by Siemens on Unit 2 rotor train consisting of the existing HP rotor, replaced LP rotors, replaced generator rotor and the existing exciter rotor showed the presence of a torsional mode with frequency close to 120 HZ. During startup, the frequency migrated through 120 HZ resonance as the load was increased and at full load it had a

frequency of 119.65 HZ. Considering this test on Unit 2 as indicative of the torsional behavior of the Unit 1 rotor train, torsional tuning of the Unit 1 rotor train by installing a redesigned jackshaft and mass rings on the turbine end coupling of the LP1B rotor is planned in order to shift the torsional natural frequency away from 120 HZ.

According to Siemens, the limited field data available for the 13.9m^2 rotors show a significant difference in the low pressure blade vibration under similar operating conditions on different units within the 13.9m^2 rotor fleet operating in the industry. The difference may have co-relation with the LP exhaust profile. A blade vibration monitoring (BVM) system when installed on the last row of blades can allow for on-line calculation of first and second mode blade vibration amplitudes for each blade of the row. The on-line data can be recorded continuously and used to provide annunciation of off-normal conditions during monitoring. The BVM requires installation of probes with sensors, instrument and optical cabling, fiber optic communication module (FOCM) and processing unit. The processing hardware (BVM Main Chassis and IO Expansion Module) are housed in a rack mounted cabinet, the FOCM will be mounted on top of this cabinet. The processing hardware requires 120/220 VAC power supply and will be configured for 120 VAC.

Installation of a Dynamic Pressure Measurement (DPM) system will allow for the LP turbine's exhaust profile to be analyzed. It is planned to install both blade vibration monitoring and dynamic pressure measurement systems on the LP turbine for historical record as well as to have co-relation data to facilitate root cause analysis. With both systems installed, data on the LP turbine's exhaust profile can be analyzed in conjunction with measured blade vibration responses. The dynamic pressure measurement system requires installation of four (4) pressure sensors in each end of the LP turbine rotors. Data from the pressure sensors are transmitted to a signal conditioner and then to a high speed data recorder.

The DPM system is planned to be temporary while the others will be permanently installed. The redesigned jackshaft and mass rings for torsional tuning, the BVM and the DPM systems are being procured from Siemens.

EC 246554 implements activities that prepare the plant for operation at Extended Power Uprate (EPU) conditions, as described in St. Lucie Unit 1 EPU License Amendment Request (LAR) (L-2010-259). Specifically, EC 246554:

- Replaces existing low pressure (LP) rotating assemblies, inner casings, outer glands and hood spray equipment with

newly designed and manufactured assemblies and components

- Rebabbit bearings and modify outer LP casing to accommodate the replacement inner casing
- Replace existing bearing oil lift pump motor with 20 HP motor, circuit breaker and thermal overload relay
- Install torsional vibration monitoring equipment
- Install blade vibration monitoring equipment (BVM) and dynamic pressure monitoring equipment (DPM)
- Replace the jackshaft located between LP1A and LP1B and install shrink ring on the LP1B coupling flange

Based upon the 50.59 Applicability Determination and Screen assessment, the changes proposed by EC 246554 that could adversely affect a UFSAR described design function is:

1. The Siemens BB281-13.9m2 LP turbine rotors were analyzed by Siemens using a new probabilistic turbine missile methodology. Therefore, this represents a new methodology used in analyzing the probability of missile generation.

Siemens Technical Report CT-27455, Revision 1, "Missile Report FPL St. Lucie Units 1 & 2," concluded that the probability of generating a turbine missile is equal to 1.88E-06, which is below the NRC recommended threshold value of 1.0E-05 for an inspection interval of 100,000 hours. This is consistent with the constraints and limitations identified in the NRC safety evaluation for TP-04124, which states the turbine can be safely operated for 100,000 hours between turbine disc inspections and quarterly turbine stop valve tests as long as no cracking is detected in the discs during inspections.

PERMANENT MODIFICATION EC 246556

10 CFR 50.59 EVALUATION REVISION 0

MAIN STEAM ISOLATION VALVE UPGRADE

Summary:

The Main Steam Isolation Valves provide the capability to isolate the safety related portion of the Main Steam Supply (MSS) system from the non-safety related portion of the MSS. The MSS system transports steam from the steam generator and delivers it to the main turbine, moisture separator reheaters (MSRs), steam jet air ejectors (SJAEs), hogging ejectors, gland seal steam and auxiliary steam systems during normal operation. It performs its decay heat removal function, with MSIVs closed, via the atmospheric steam dump valves and/or the steam driven auxiliary feedwater pump; or with MSIVs open, the steam bypass control system can be used.

This plant change upgrades St. Lucie Unit 1 Main Steam Isolation Valves (MSIVs) HCV-08-1A and HCV-08-1B, including redesign and replacement of internal sub-components. In addition, existing MSIV pneumatic actuators require replacement with hydraulic actuators. The new actuators have a nitrogen pressure closure system which replaces the spring closure mechanism of the existing actuators. This design change includes the re-design and replacement of sub-components internal to the MSIVs, the replacement of the existing spring assisted pneumatic MSIV actuators with a more robust design, which includes a hydraulic system for valve operation (pneumatically driven) with a nitrogen pressure assisted closure system.

As a result of the actuator replacement, the following changes are also required:

- Rotation of MSIV MOV equalizing valve actuators (MV-08-1A & 1B) along with field wire and conduit redesign
- Modification of the MSIV valve controls to accommodate the new hydraulic actuator
- Removal of existing MSIV solenoid valves and pressure switches, as well as redesign of the associated wiring/conduits for the new hydraulic actuator
- Redesign of the existing air piping to the new actuator air drive hydraulic pumps
- Changes to plant emergency operating procedures
- Installation of additional personnel access grating on the steam trestle adjacent to the MSIVs.

The 50.59 Screening Process, which included a review of the Design Change Checklist and a failure modes and effects analysis (FMEA), identified several proposed activities requiring a 50.59 Evaluation. An evaluation of these proposed activities produced the following conclusion.

The FMEA did not identify any new failure modes or event sequences that could result in a single active failure which would prevent the MSIVs from remaining open under normal operations or from closing when required. The failure modes / event sequences for loss of MSIV closure function remain applicable to the new actuator system. However, the new design is susceptible to loss of the MSIV closure function due to failure of pressure retaining components. The modified MSIVs will fail as-is for any single active failure associated with the redundant solenoid valves. The modified MSIVs will fail closed on a failure of the hydraulic control subsystem to maintain pressure on the underside of the actuator piston. Loss of hydraulic fluid pressure boundary is no more or less likely to occur than loss of Instrument Air (IA) pressure boundary and thus there is no impact to the likelihood of occurrence of an accident previously evaluated in the UFSAR or a malfunction of an SSC important to safety previously evaluated in the UFSAR.

A failure to maintain the nitrogen charge pressure will prevent the MSIV from satisfying its safety function of closing upon an ESFAS or operator initiated demand signal. This is a passive failure. Passive failures are not postulated to be initiated during the initial phase of accident events consistent with NRC guidance on Single Failure Criteria. Failure of the MSIV mechanical actuator spring in the current design would also result in loss of the MSIV closure function. Therefore the safety function of the MSIVs is maintained to the same level of safety as the current design.

In any event, the potential loss of nitrogen charge pressure is ameliorated by the addition of the LO and LO-LO Nitrogen Pressure alarm signals which are being incorporated into Annunciator Windows Q-47 and Q-49 to prompt an appropriate operator manual response to the MSIV actuator nitrogen subsystem failure.

Thus this change is considered neutral to nuclear safety under the EPU configuration, and a net benefit under the current plant configuration.

- Environmental qualification, including seismic qualification of new and replacement components was performed and found to be acceptable for their operating conditions. Thus this change is considered neutral to nuclear safety under the EPU

or the current plant configuration.

- Emergency Operating Procedure 1-EOP-99 Attachment I describes MSIV local closure. These instructions will be revised to utilize the new local equipment to close the Enertech actuator. This change is considered neutral to nuclear safety under the EPU or the current plant configuration.
- With respect to electro-magnetic compatibility (EMC) and radio frequency interference, the MSIV upgrade introduces new electrical switches that actuate only in response to mechanical forces, and solenoid valves that respond only to the application of DC voltages in excess of 90 VDC. Existing components that interface electrically with the new components consist of relays, selector switches, lights, fuses and annunciator, all of which operate at a common voltage of 125 VDC. New electrical components in RTGB-106 (located in the Control Room) consist of two 125 VDC relays, which are equivalent to some of the existing relays in that area. Therefore, the equipment installed per this EC are not expected to introduce any new EMC concerns, nor are they expected to be any more susceptible to EMC issues than the existing equipment. The new solenoid valves require significantly less power (14 W) than the existing ones, and produce negligible back-EMF when de-energized. Therefore, the new solenoid valves are not expected to reduce the service life of the existing MSIV tripping relays, control switches and other contacts within the MSIV control circuits. As a result, these changes are considered neutral to nuclear safety under the EPU or the current plant configuration.
- With respect to thermal-hydraulic conditions associated with the EPU, all MSIV internal parts have been re-designed to withstand the operating conditions of the main steam system per Kalsi Design Report 2916C. The actuator manufacturer has demonstrated through calculation - and will demonstrate through factory testing - that the performance of the hydraulic resistance of the valve is unchanged from the original valve. Therefore, the modifications do not impact the hydraulic performance of the valve or Main Steam System. As a result, these changes are considered neutral to nuclear safety under the EPU or the current plant configuration.

PERMANENT MODIFICATION EC 246557

10 CFR 50.59 EVALUATION REVISIONS 1, 2, 3, 4, & 5

POWER UPRATE - HYDROGEN PURGE AND CONTAINMENT PRESSURE CONTROL SYSTEM

Summary:

The Containment Hydrogen Purge system draws gas from the dome of the containment via penetration P-57, through the filter train and to the vent stack using the purge fans HVE-7A/7B. This is a post-Loss of Coolant Accident (LOCA) manually controlled function used to reduce hydrogen accumulating in containment when the accident conditions reach a phase where hydrogen generation takes place. The outside air cooling is used to reduce temperature from the filter train.

The pressure control function (new) will replace the existing local controls to reduce containment pressure as needed (during normal operation) and controlled by operators in the Control Room.

Due to accident analysis for EPU, the maximum operating atmospheric pressure in containment is decreasing from 2.4 psig to 0.5 psig (based on the License Amendment Request (LAR L-2010-259) and thus the Control Room operators need a way of relieving pressure build up via a pressure control function. Containment integrity will require auto isolation of the penetration making local manual operation of the valves unacceptable during operation. Therefore, the purge isolation valves, flow control valves, and purge fans require modifications to be remotely operated from the Control Room. This modification is limited to installing the equipment and does not change the allowed operating pressure inside containment.

EC 246557 implements activities that prepare the plant for operation at Extended Power Uprate (EPU) conditions, as described in St. Lucie Unit 1 EPU LAR (L-2010-259). The proposed activities install the hardware necessary for operations of the Hydrogen Purge System in a containment pressure control function capacity. The ability to achieve a lower Containment operating pressure will support future uprated power operations, which require a lower initial Containment pressure. This 50.59 Evaluation addresses the period between modification implementation during the SL1-24 outage and approved operations at EPU conditions. Implementation of EC 246557 is not dependent upon EPU LAR approval by NRC. Specifically, EC 246557 will:

- Replace normally closed manual operated Hydrogen Purge

System isolation valve (V-25-14) with remote controlled air operated valves (FCV-25-20, FCV-25-21) with Containment Isolation Signal (CIS) logic,

- Replace existing differential pressure indicating switches PDIS-25-1A and -1B,
- Relocate local push button stations to the Control Room,
- Relocate instrument recorders to the Control Room, add instrument air isolation valves,
- Change V-25-17 from normally closed to normally open,
- Change V25013 from normally locked closed to normally open,
- Change FCV-25-10 from normally closed to throttled,
- Adjust setpoint for relative humidity (RH) on moisture indicator MI-25-3,
- Add new alarm setpoints (High Containment Pressure and High Containment Vacuum),
- Remove HVE-7A/B interlock from FCV-25-10,
- Remove HVE-7A/B interlock to FS-25-17A/B.

The 10 CFR 50.59 Screening for EC 246557 resulted in the following activities Screening In. These are summarized below and are the subject of the 50.59 Evaluation.

- Remote Manual Valve Operation: The design function of Hydrogen Purge System will be adversely affected because the system is changing from manual to remote manual control with the manual isolation valves being replaced with air operated valves and the components in the system having their local pushbutton stations moved to the Control Room.
- Operating Procedures: The changes to the operating mechanism for the Hydrogen Purge System Containment isolation valves, i.e., going from passive to active control, adversely affects how UFSAR described SSC design functions are to be performed as a result of implementation of EC 246557. The necessary operating procedure revisions adversely affect how the UFSAR SSC design functions are controlled as a result of implementation of this modification.

The Containment Hydrogen Purge System isolation valves are being changed from manually operated to air operated actuation. This change in actuator type increases the probability of a malfunction. However, the NRC's Resolution to Generic Safety Issues: Issue 158, "Performance of Safety-Related Power-Operated Valves under Design Basis Conditions," states that their analysis of "data for AOVs determined a demand failure probability of 1.1 x 10^{-2} for AOVs in risk significant systems and 4.2 x 10^{-2} for all AOVs." Therefore, the change to AOVs does not represent a more than minimal increase in the likelihood of occurrence of a

malfunction. Additionally, the system alignment of the valves is single failure proof and any cause for valve malfunction results in a fail-safe state. Thus, a malfunction of these valves would not preclude accomplishing their safety functions.

The proposed activity will reduce the radiological consequences that have been analyzed by replacing manual isolation valves with remote controlled air operated valves. The new Hydrogen Purge System isolation valves are designed to have a closure time of 5 seconds based on similar Containment isolation valve response times. This value is well below the 4.75 minutes (285 seconds) assumed for manual operator action that has been evaluated in NAI-1101-033, "St. Lucie 1 LOCA Radiological Analysis with Alternate Source Term." The 5 seconds is below the 285 seconds which is the amount of time credited in the alternate source term (AST) calculation NAI-1101-033 for release time until isolation is complete. The Hydrogen Purge System Containment isolation valves will close well in advance of damaged fuel releases of fission gases, which is assumed to occur as early as 30 seconds into a design basis LOCA event in the AST calculation. Implementation of EC 246557 will not result, either directly or indirectly, in an adverse effect to any safety functions required for analyzed accidents and do not increase any radiological hazards.

PERMANENT MODIFICATION EC 246559

10 CFR 50.59 EVALUATION REVISIONS 1, 2, & 3

POWER UPRATE - IMPROVE HOT LEG INJECTION FLOW

Summary:

Extended Power Uprate (EPU) conditions will result in an increase to the boil-off rate in the reactor core following certain accidents as described in the UFSAR. The impact of this increased rate, as well as Nuclear Regulatory Commission (NRC) imposed accident analysis methodology changes, requires that when EPU is implemented that the required flow rate for Hot Leg Injection be increased from its current value of 190 gpm to the new EPU required flow rate. An initial EPU target flow rate of 250 gpm was established. It was demonstrated that the flow paths through the 1B warm-up line and the HPSI 1A/Pressurizer Aux Spray piping could not support this target flow rate. It was also demonstrated that all flow paths could meet the current 190 gpm flow requirement without modification.

To mitigate against boron precipitation within the reactor vessel at EPU conditions, EC 246559 increases the hot leg injection flow capabilities to the Reactor Coolant System (RCS). In addition, this increase in flow capability will ensure that the current licensing basis (CLB) requirement of 190 gpm remain satisfied. This Applicability Determination and Screen (Phase 1 of EC 246559) will not address hot leg injection flow requirements at EPU conditions, which will be considered in a subsequent (Phase 2) of EC 246559 and associated 50.59 Screen. Specifically, EC 246559:

- Increases Low Pressure Safety Injection (LPSI) pump delivery capability (preferred path) and Containment Spray (CS) pump (alternate path) hot leg injection flow rate via the hot leg suction flow path
  - Replace LPSI globe valve MV-03-1B with a gate valve
- Increases High Pressure Safety Injection (HPSI) pump hot leg injection flow rate delivery capability via the pressurizer auxiliary flow path (alternate path)
  - Add line 2-CH-1002 as a parallel flow path that bypasses the regenerative heat exchanger
  - Install a pipe support on 2-CH-1002
  - Modify existing pipe supports on line 2-CH-109
  - Add local flow indicator FI-2212 with a 0-350 gpm range
  - Add check valve V02359 to pressurizer auxiliary spray line I-2-CH-346 to prevent unheated water from

entering the RCS

- Change MV-02-1 (renamed the regenerative heat exchanger bypass valve) to a remotely operated, normally open isolation valve, with indicating lights powered from 120V AC Power Panel PP-102A, and remove interlocks with MV-02-2
- Change MV-02-2 to a normally open valve, with its 480V MCC breaker procedurally controlled open, indicating lights on the RTGB disabled, and remove interlocks with MV-02-1 (the throttling function for RCP seal injection is being abandoned by EC 249576)
- Add flow restriction orifice SO-02-2 to limit flow diversion during hot leg injection.

Based upon the 10 CFR 50.59 Applicability Determination and Screen assessment, the changes proposed by EC 246559 that could adversely affect a UFSAR described design function is:

1. Current hydraulic analyses of the HPSI pump hot leg injection flow rate via the pressurizer auxiliary spray flow path show that the regenerative heat exchanger shell-side specified design condition flow of 132 gpm is exceeded.

A flow induced vibration analysis of higher than design flows through the regenerative heat exchanger shell-side was performed. The results show that the regenerative heat exchanger will be able to handle the increased flow requirements for operation at the Current Licensing Basis conditions.

PERMANENT MODIFICATION EC 246560

10 CFR 50.59 EVALUATION REVISIONS 0 & 1

PSL1 STEAM BYPASS CONTROL SYSTEM REPLACEMENT

Summary:

This modification replaces the Steam Bypass Control System (SBCS), monitoring and display system with new Distributed Control System (DCS) equipment and software. This modification interfaces with the following ECs: EC 246497 PSL-1 ERDADS Replacement, EC 236119 SBCS Valves Positioner Replacement, EC 246545 DEH Control System Upgrade, EC 246561 NSSS Setpoints and Scaling, EC 246544 BOP Setpoints and Scaling, and EC 246553 Power Uprate - DCS Mods for LEFM and FW Ctrls. The SBCS controls will be replaced with DCS equipment and software for use at EPU conditions. Per UFSAR Section 7.7.1.3.2, the existing SBCS bypasses up to 29% of the steam to the condenser, however, the bypass flow capability will be increased as discussed under EC 236119. The effects of the increased bypass flow capability and the impact on the Excess Load Class 1 Accident discussed in UFSAR Section 15.2.11.1 will be covered by EC 236119, the EPU LAR and/or Interim Cycle Evaluation.

The SBCS Master Controller PIC-8010, and M/A stations (HIC-8801/8802/8803/8804) located on RTGB-102 will be replaced with two (2) DCS compatible touch screen M/A stations (PIC-8010 and HIC-8801/02/03/04). The open/close status for the valves will be incorporated into the M/A displays and graphic displays. The SBCS calculator and test panel located in back of RTGB 104 cabinet will be replaced with DCS compatible components. The new SBCS will interface with SBCS steam dump to Condenser valves (PCV-8801, PCV-8802, PCV-8803, PCV-8804 and PCV-8805) positioner components which will be replaced with DCS compatible (HART protocol) digital valve positioners under EC 236119. To accommodate the installation of the above mentioned M/A stations (SBCS), the existing LPFWCS/FWRS M/A stations (LIC-9005/9006 & FIC-9011/9021) will be remounted on a hood along with the new SBCS M/A stations.

The existing Condenser 1A Vacuum Pressure indicator (PI-10-07) located on RTGB 101 will be replaced with Versatile (VMI) Model 2000-01/Otek Model HI-Q2000 similar to the Unit 2 indicator and a revised scale/range to match the pressure transmitter PT-10-07 is being rescaled by EC 246545. This signal will only be used on the SBCS displays and does not impact the SBCS design and is not used for control.

This modification is implemented as a phase of the DCS

installation at Plant St. Lucie (PSL), which is a part of the Extended Power Uprate (EPU) project. This modification is scheduled to be installed in the Cycle 24 refueling outage (Modes 5 and 6 and defueled). The reason for this modification is to reduce the instability (oscillations) of the SBCS Steam Dump to Condenser Valve controls and to upgrade this control system by replacing it with a DCS. The SBCS Steam Dump to Condenser Valve pneumatic positioners are also being replaced with digital positioners to enhance tuning and diagnostic capability, under a separate modification.

A 10 CFR 50.59 Applicability Determination and Screening has been performed and has identified the upgrade from analog to digital controls and the way that the SBCS is controlled and monitored is being fundamentally altered. Therefore, as discussed in the 10 CFR 50.59 Resource Manual Guidance Document, this attribute of EC 246560 is subject to a 10 CFR 50.59 Evaluation.

The replacement Unit 1 SBCS equipment has design features and performance characteristics that, when compared to the existing equipment, do not increase the frequency of occurrence of an accident. The new Foxboro DCS is fault tolerant, and can sustain internal module failure without the loss of system functionality due to the redundant architecture. The changes associated with this modification improve the reliability of the system and will therefore not increase the frequency of failures that may result in an Excess Load Class 1 Accident (UFSAR Section 15.2.11.1) due to the inadvertent opening of the SBCS steam dump and bypass valves.

All new equipment will replace equipment performing similar control and monitoring functions. No new or different failure modes have been identified that will result in a different type of accident. The changes associated with this modification will also not impact or increase the severity of any scenarios associated with the Excess Load Class 1 Accident discussed in UFSAR Section 15.2.11.1. Human Factors have been evaluated for the human-machine interfaces and the graphic displays and been found acceptable. The graphic displays will mimic existing displays for user familiarity. However, operator interface device will change and operator training will enhance that interface. The modifications performed are within established engineering and implementation criteria (e.g. Seismic Interaction, Fire Protection, electrical separation, Control Room Habitability) and will be implemented in accordance with plant approved procedures. EMI/RFI emissions will not affect the installed environment as all new equipment is either located in grounded metal cabinets or is housed in industry compliant enclosures. The changes made to the electrical system as a result of this modification do not create a possibility for an

accident of a different type than those previously analyzed for the power system. The systems affected by this modification, SBCS, FWRS/LPFWCS and ERDADS/DCS, do not perform any safety related function and are not required by the accident analyses to play a role in mitigating the consequence of a malfunction. The bounding failure to open or inadvertent opening of all SBCS steam dump and bypass valves malfunctions as described in UFSAR Sections 10.4.4, 15.2.7 and 15.2.11.1 are not impacted by this modification.

PERMANENT MODIFICATION EC 246594

10 CFR 50.59 EVALUATION REVISION 3

REPLACEMENT OF RCP 1B1 ROTATING ASSEMBLY

Summary:

To allow for future maintenance of the reactor coolant pump the RCP 1B1 whip (cable) restraints shall be permanently removed. In addition to removing an interference that impedes the disassembly of the pump and it will also reduce the radiological dose required to reinstall the 4-inch cables.

The St. Lucie Unit 1 Construction Permit was issued on July 1, 1970 and an Operating License was issued in March 1976. Prior to 1986, General Design Criterion (GDC) 4, "Environmental and Missile Design Bases," required that systems and components important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharge fluids that may result in equipment failures. In accordance with NRC Branch Technical Position ASB 3-1, plants for which construction permits were tendered before July 1, 1993, and operating licenses were issued after July 1, 1975, should follow the guidance of Appendix B of ASB 3-1 (letter by A Giambusso, December 1972, General Information Required for Consideration of the Effects of a Piping System Break Outside Containment") and also provide moderate energy piping failure analyses in accordance with Branch Technical Position ASB 3-1. Accordingly, the original St. Lucie Unit 1 design bases considered all dynamic effects (missile generation, pipe whipping, pipe break reaction forces, jet impingement forces, compartment, sub-compartment and cavity pressurizations and decompression waves with the ruptured pipe) and all environmental effects (pressure, temperature, humidity, and flooding) resulting from arbitrary intermediate pipe ruptures.

Circa ~ 1986, GDC 4 was revised to read:

> "Environmental and dynamic effects design bases. Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accident. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe

ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping."

Consistent with the revision to GDC 4, on June 19, 1987, the NRC issued Generic Letter 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements which finalized a revision to Branch Technical Position (BTP) MEB 3-1 of Standard Review Plan (SRP) Section 3.6.2 in NUREG-0800. The revisions to BTP MEB 3-1 and SRP 3.6.2 eliminated all dynamic effects and all environmental effects resulting from arbitrary intermediate pipe ruptures. This action allows the elimination of pipe whip restraints and jet impingement shields placed to mitigate the effects of arbitrary intermediate pipe ruptures, and other related changes.

On October 30, 1990, the NRC accepted Topical Report CEN-367, "Leak-Before-Break Evaluation of Primary Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems," which was submitted for staff review by Combustion Engineering Owners Group (CEOG) letter dated November 20, 1987. FPL was a participating CEOG member and St. Lucie Units 1 and 2 were included in the bounding analyses submitted.

By letter to the NRC dated August 26, 1992, FPL proposed to eliminate the dynamic effects associated with high energy pipe rupture in the reactor coolant system piping from the licensing and design bases of St. Lucie Units 1 and 2 by the application of leak-before-break (LBB) technology. This change to the licensing and design bases is permitted by revised GDC-4 of Appendix A to 10 CFR 50.

By NRC letter dated March 5, 1993, the staff concluded that since the St. Lucie Units are bounded by the CEOG analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie Units.

The Unit 1 UFSAR was updated to incorporate the effects of the staff's approval. Section 3.1.4 was revised to read:

> Due to the application of leak before break methodology to the RCS hot and cold leg piping, the dynamic effects of a loss of coolant accident do not have to be considered. A technical evaluation was performed to demonstrate that the probability or likelihood of large pipe breaks occurring in the primary coolant loops is sufficiently low that they need not be a design basis.

UFSAR Section 3.6.2 was revised to include the following acceptance criteria:

It should be noted that circumferential (guillotine) and longitudinal (slot) breaks in RCS hot and cold leg piping are no longer considered a design basis for GDC 4. The primary loop piping is not susceptible to failure from the effects of corrosion, water hammer, fatigue, brittle fracture or indirect causes such as missiles or failure of nearby components. As a result, the mechanical/structural loadings associated with the dynamic effects of a large hot or cold leg break need not be considered.

The proposed permanent removal of the upper two 4-inch reactor coolant pump RCP 1B1 whip (cable) restraints meets the acceptance criteria found in Generic Letter 87-11. Also as documented in NRC letter dated March 5, 1993, the NRC staff has concluded that since the St. Lucie Units are bounded by the CEOG analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie Units. The permanent removal of the upper RCP 1B1 whip restraints meets the acceptance criteria of BTP 3-1, as contained in SRP Section 3.6.2, in that absent the whip restraints the primary coolant system piping continues to meet the applicable ASME Code design requirements.

PERMANENT MODIFICATION EC 249576

10 CFR 50.59 EVALUATION REVISION 0

RCP 1B1 SEAL FLEXIBLE HOSE INSTALLATION

Summary:

Seal injection will be removed from RCP 1B1 and disabled on the other three RCPs. A blind flange will be placed over the seal connection for seal injection for RCP 1B1. On all four pumps the isolation valve outside the pump shroud will be closed.

During operation of St. Lucie Unit 1 in 1977 and 1980, component cooling water (CCW) to the reactor coolant pump (RCP) seal heat exchangers was lost resulting in damage to the seals and requiring the replacement of the RCP seals. As a result, an independent seal injection system was added.

UFSAR Section 9.3.4.2.1 states, "A reactor coolant pump (RCP) seal injection system is provided from the chemical and volume control system (CVCS). This system, which was originally designed as a backup system for seal cooling, may be used to inject water into the RCP seals during RCS fill and vent in order to prevent foreign material from entering the seals. According to JPN-PSL-SENJ-93-001, the RCP seal injection was added as a backup to CCW seal cooling, but no credit was taken in the safety analysis for its operation following a loss of CCW or a Station Blackout. Its use is no longer needed."

The evaluation JPN-PSL-SENJ-93-001 Revision 1, "Safety Evaluation for Deletion of RCP Seal Injection," also stated that, "although seal injection is not required, it should continue to be used for the fill and vent operations."

Based upon above, the only intent of RCP seal injection as currently used is as a precautionary measure to limit floating debris from entering the lower RCP seal cavity during RCS flood-up from elevation below 33′ to above 33′. The RCP seal is not expected to fail catastrophically as a result of expected debris entering the seal and based upon the Operational Decision Making (ODM) Bulletin, the RCP seal injection is being abandoned. Therefore, this 10 CFR 50.59 evaluation is prepared to evaluate the permanent removal of seal injection from RCP 1B1 and elimination of seal injection from RCPs 1A1, 1A2, and 1B2.

To remove seal injection from RCP 1B1, the seal injection line is removed from the seal to an existing flange connection outside the shroud. A blind flange is bolted to the seal injection connection on the seal. A blind flange is bolted to the existing

flange connection outside the shroud. Valves V2302 and V01108 are closed. The blind flange will meet the design requirements.

To eliminate seal injection from the other pumps the following valves are closed:

RCP 1A1 - V02300 and V01102
RCP 1A2 - V02301 and V01105
RCP 1B2 - V02303 and V01111

Seal injection that was originally designed to serve as a backup system for seal cooling has been evaluated as no longer needed as stated in UFSAR Section 9.3.4.2.1. Leakage from the reactor coolant pump past the pump shaft is controlled by the shaft seal assembly and reactor coolant entering the seal chambers is cooled and collected in closed systems so that reactor coolant leakage to containment is essentially zero. There is sufficient instrumentation on the reactor coolant pump to detect seal degradation and leakage. All these reactor coolant pump control grade instruments have appropriate high or low range alarms to alert the operator to seal malfunction. Thus, in the event of a seal malfunction, instrumentation in the form of pressure transmitters, a flow meter, and a temperature detector is provided to alert the operator to a potential problem. Therefore, the removal/isolation of seal injection does not physically alter RCPs, RCS performance or operator action that could affect the seal leakage and the current UFSAR analyses remain bounding.

The use of seal injection into the RCP seals during RCS fill and vent in order to prevent foreign material from entering the seals has marginal value. RCP seal injection is in service for only approximately one hour during RCS flood up from below 33 feet to above 33 feet elevation.

PERMANENT MODIFICATION EC 250014

10 CFR 50.59 EVALUATION REVISIONS 0 & 1

DIESEL OIL STORAGE TANK OPERATING MARGIN

Summary:

This proposed plant change upgrades St. Lucie Unit 1 DOST overflow lines DO-1 and DO-2, adding a loop seal to increase the effective overflow height. The maximum fill limit is increased, and the low level alarm setpoint is increased.

As a result of the overflow line modification, the following changes are also required:

- Addition of vent lines to act as siphon breaks, with flame arrestors to maintain fire protection capability consistent with the existing DOST configuration
- Addition of stress loops in the overflow pipes
- Re-design and replacement of existing pipe supports
- Resetting the DOST level switches to new tank low level alarm setpoint

The 10 CFR 50.59 Screening resulted in one activity screening in. This activity is summarized below and is addressed in the 10 CFR 50.59 Evaluation.

> Seismic Design: The additional fuel capacity increases the static and dynamic (sloshing) loads on the seismically designed tank structure and its foundation.

The increase in the DOST maximum storage capability will increase the total weight that is transferred to the DOST foundations. The DOST foundations were designed to support a tank completely filled with water. Water is denser than diesel fuel and 2 inches of freeboard will be maintained at the maximum tank level. Therefore, the existing foundations can support the additional volume of diesel fuel. As a result, this change is considered neutral to nuclear safety.

The effect of the increased level of oil was shown to be acceptable for design basis seismic events in calculation 25486-166-CYC-0001-00002. The increase in fuel oil storage capacity has no adverse effect on the ability of the DOST to withstand design basis earthquake loads. Calculation 25486-166-CYC-0001-00002 confirms that the new overflow piping and loop seals do not introduce a seismic II/I concern.

As a result, this change is considered neutral to nuclear safety. The primary facts to support this conclusion are detailed below.

- The new DOST overflow lines and loop seals are supported from the tank foundation. The piping and additional oil volume loads and embedded plate qualification are provided in calculation 25486-166-PHC-FDT-00001 and are acceptable. No modifications to the embedded plates or foundation are required.
- The new DOST overflow lines and loop seals are analyzed for seismic II/I concerns. A failure of the overflow piping or support could potentially damage the safety related DOST or safety related drain lines (I-2-DO-3 and I-2-DO-4). The tank drain lines are below the overflow piping offset 15 degrees on the tank radius. Calculation 25486-166-CYC-FDT-00001 has evaluated/designed the overflow piping/loop seal and support to ensure that a failure will not occur during design basis conditions.
- The overflow lines will be connected to the tanks using a mechanical coupling. The overflow piping will be supported from the tank foundation. Piping and supports have been satisfactorily analyzed for seismic loading in calculation 25486-166-PHC-FDT-00001.

Unit 1 DOST was evaluated for an increase in oil level and found to have adequate seismic strength for the effects of OBE and SSE events. Note that a local shell evaluation for the overflow nozzle was performed and found to have adequate seismic strength for the effects of a OBE or SSE event.

SECTION 2

10 CFR 50.59 EVALUATIONS

EVALUATION SENS-10-026

REVISION 0

REVISION OF UNIT 1 HYDROGEN PURGE SYSTEM PROCEDURE 1-NOP-25.02 TO CONTROL CONTAINMENT PRESSURE

Summary:

The reliability of the 1A and 1B Instrument Air Compressors inside the Unit 1 Containment has degraded. These compressors supply Instrument Air to pneumatically operated valves, instruments and controls located inside containment and provide a means to reduce containment pressure. The outside Containment Instrument Air compressors 1C and 1D located outside containment can supply Instrument Air inside Containment via valve MV-18-1, which receives a CIS.

As a contingency, an alternative method is being pursued to supply Instrument Air inside Containment with outside Containment Instrument Air compressors and to use a hydrogen purge line with manual containment isolation valves to control containment pressure. Unit 1 procedure 1-NOP-25.02 has been revised to use the hydrogen purge system to control containment pressure within the limits established by Technical Specification 3.6.1.4. The procedure revision involves stationing an operator at the manual containment isolation valves V25013 and V-25-14 who will be in constant communication with the Control Room. If a CIAS, SIAS, or MSIS actuation occurs, then the operator will immediately close the assigned valves to isolate penetration P-57. One of the Containment Hydrogen Purge Fans (HVE-7A or HVE-7B), which have a capacity of 500 cfm, will be run while the containment isolation valves are open. The time for manual closure of the hydrogen purge system containment isolation valves is expected to exceed 30 seconds. The 10 CFR 50.59 Applicability Determination / Screening for the revision to 1-NOP-25.02 concluded that the proposed change involves a change to an SSC that adversely affects an UFSAR described design function by exceeding 30 seconds for closure of containment isolation valves following a LOCA. The 10 CFR 50.59 Applicability Determination / Screening also concluded that the proposed change replaces the completely automatic isolation of open containment penetrations with manual isolation of P-57, which constitutes a change to a procedure that adversely affects how UFSAR described SSC design functions are performed or controlled.

The current Unit 1 LOCA and MSLB inside containment radiological consequence analyses were used as a basis to evaluate the consequence (dose) of revising 1-NOP-25.02 to use a hydrogen

purge line with manual containment isolation valves to control containment pressure. The inputs and assumptions of the current licensing basis analysis of record for LOCA and MSLB inside containment are assumed for this analysis, except that the main containment purge system is assumed to be secured and the hydrogen purge system is assumed to be operating at the onset of the accident. 500 cfm purge flow is assumed to be provided by either the HVE-7A or HVE-7B Containment Hydrogen Purge Fans through the charcoal adsorbers (98% efficiency assumed) and HEPA filters (99% efficiency assumed).

The revised Unit 1 radiological consequence analyses of record assumed that there is no bypass of the hydrogen purge charcoal adsorbers and HEPA filters by the 500 cfm purge flow. With a dedicated operator at manual containment isolation valves V25013 and V-25-14 in constant communication with the Control Room, if a CIAS, SIAS or MSIS actuation occurs, then the operator will immediately close the assigned valves to isolate penetration P-57 within 225 seconds (3.75 minutes). This results in increasing the Unit 1 Control Room LOCA total dose of 4.69 rem TEDE by 0.029266 rem TEDE. For the MSLB inside containment, the reported 29% DNB case total dose and the 6.1% fuel centerline melt (FCM) case total dose remain the same with the only change being in the Non-Noble Gas dose term. This term decreases very slightly for the 29% DNB case and remains the same for the 6.1% FCM case.

Performance of revised procedure 1-NOP-25.02 to control containment pressure within the limits established by TS 3.6.1.4 does not significantly affect the ability of any SSCs to perform their safety related functions or significantly affect how UFSAR described SSC design functions are performed or controlled. The conclusion of this 10 CFR 50.59 Evaluation is that performance of revised procedure 1-NOP-25.02 to control containment pressure within the limits established by TS 3.6.1.4 does not require approval from the NRC prior to implementation.

EVALUATION SENS-10-027

REVISION 0

UFSAR CHANGE TO RENDER SPENT FUEL POOL FUNNELS OPTIONAL

Summary:

The use of spent fuel storage rack funnels, while assisting the insertion of fuel assemblies into the racks, has presented challenges in managing fuel moves in the pools as well as presenting interferences with fuel assembly withdrawals. As greater activity in the spent fuel pools has increased (e.g., Zero by 2010 fuel inspections, offloading fuel to the ISFSI, potential spent fuel rack inserts to support EPU, etc.), the use of funnels is likely to become a serious hindrance and potential safety and ALARA issue (i.e., longer times in the spent fuel pool, interferences with equipment, etc.).

To address these problems, the Units 1 and 2 UFSAR documents will be changed to ensure that use of the funnels is optional. As the current UFSAR language is ambiguous with respect to the need for funnel usage, the UFSAR change will clarify that the use of funnels is optional. This will safely provide the flexibility required to perform the increased amount of pool activities that have arisen.

The purpose of this 10 CFR 50.59 Evaluation is to determine if the activity can be implemented without the submittal of a license amendment to the NRC. This activity represents an adverse effect from a 10 CFR 50.59 Applicability Determination / Screening viewpoint because this activity consists of rendering the funnels as optional aids in spent fuel rack insertion which constitutes a change to a procedure that affects how UFSAR described SSC design functions are performed and controlled. Therefore, a 10 CFR 50.59 Evaluation is required.

The current Units 1 and 2 descriptions of spent fuel rack funnels state their capability to assist in the insertion of fuel assemblies into the spent fuel racks that do not have leading edges (i.e., Region 2 in Unit 1 and both Regions 1 and 2 in Unit 2). However, fuel assemblies cannot be withdrawn through racks that are covered by a funnel and the movement of funnels is time consuming and can increase crew dose should a large number of funnels require re-positioning. In addition to funnels, the spent fuel handling machine uses a J-hook design grapple with a shroud to ensure a sound grasp of the assembly and the spent fuel handling machine has underload settings which help prevent fuel assembly grids from catching on the rack edge or damaging the

rack itself. The fuel assembly designs include chamfered grid tabs to minimize the possibility of a grid catching the edge of a spent fuel rack cell. Further, funnels provide no additional protection for the fuel clad versus the fuel rack itself. These are the primary means to protect fuel assembly grids during insertion into the racks. A review of PWR industry best practices indicate that most utilities with high density spent fuel racks (i.e., no leading edges) no longer use funnels as the logistical and ALARA considerations outweigh the minimal amount of additional protection of the grid and the rack from a mis-positioned fuel assembly. The change of the status of the spent fuel pool rack funnels to optional use does not adversely affect the ability of any SSCs to perform their safety related functions or adversely affect how UFSAR described SSC design functions are performed or controlled. The 10 CFR 50.59 Evaluation demonstrated that no prior NRC review and approval is required.

SECTION 3

RELOAD EVALUATION

ENGINEERING CHANGE 273422

10 CFR 50.59 EVALUATION REVISION 1

ST. LUCIE UNIT 1 CYCLE 24 RELOAD

Summary:

This Engineering Change - Design Change Package (hereafter referred to as EC-DCP or EC), provides the reload core design of St. Lucie Unit 1 Cycle 24 developed by Florida Power & Light Company (FPL) with input from AREVA-NP. The Cycle 24 core is designed for a nominal cycle length of 12,216 EFPH, with an EOC boron concentration of ~ 155 ppm, based on an actual end of Cycle 23 length of 11,477 EFPH.

The primary design change to the core for Cycle 24 is the replacement of 100 irradiated fuel assemblies with 100 fresh Region FF fuel assemblies. All assemblies in the Cycle 24 reload core are of the debris resistant design. The fuel assembly design of Region FF fuel is the same as that of the previous cycle Region EE fuel design. This fuel design includes the use of high thermal performance (HTP) spacer grids, high mechanical performance (HMP) lower grids and the use of FuelGuard lower tie plate. The fuel assembly design for Region FF fuel utilizes radial enrichment zoning (REZ) similar to that used in previous regions, to gain margin in steaming rate to improve fuel performance with respect to fuel rod corrosion and crud deposition. The only physical change to the fuel in this cycle is related to the manufacturing where the fuel pellets are manufactured with chamfered bottom and top edges. The minimum RCS refueling boron concentration requirement is increased from 1720 to 1900 ppm to cover both pre-EPU and EPU conditions. An additional change included in this EC-DCP is the replacement of four type 3 CEAs with four equivalent type 3 CEAs in the Cycle 24 core. Changes in the safety analysis inputs with respect to Cycle 23 include: 1) A revised power measurement uncertainty at lower power levels; 2) The High Pressurizer Level Error Alarm decreased from 10% to 5%; 3) Increase in main feedwater (MFW) overcapacity from 10% to 25% to support EPU MFW modifications; 4) Increase in the total SBCS flow rate from 5.1×10^6 lbm/hr to 7.5×10^6 lbm/hr to support EPU modifications; 5) Modification to the SBCS Pressure Modulation Setpoint; 6) Modification of the SBCS Temperature Modulation Program; and 7) Changes to the containment spray (CS) pump maximum flow rates from 3450 gpm/pump to 4050 gpm/pump due to CS modifications. The decrease in the Containment Spray Pump Design Flow Rate and the increase in CS system fill times due to CS modifications do not impact the Chapter 15 reload analysis. The impact of these changes on

containment peak pressure/temperature analysis will be covered for EPU conditions in EC 250013 as appropriate.

As FPL plans to implement mid-cycle Extended Power Uprate (EPU) for Cycle 24, with a power level increase from 2700 MWth to 3020 MWth, there will be some major changes to be implemented which will impact Cycle 24 as it relates to safety analysis, licensing, fuel mechanical design, and operations considerations. These changes, which include several Technical Specifications (TS) changes, involve re-analysis/evaluation of all design basis events described in the Updated Final Safety Analysis Report (UFSAR). The changes are described in the License Amendment Request (LAR), submitted in L-2010-259 (and subsequent NRC submittals). As these changes have not been approved by the NRC prior to plant startup operations, this reload EC does not rely on these new design basis analyses. This EC will address operation of the plant through all modes for Cycle 24 assuming non-EPU conditions.

The implementation instructions provided in this EC-DCP, for core reconfiguration from Cycle 23 to Cycle 24, support a full core off-load only. This EC-DCP supports offload initiation as early as 145 hours after Cycle 24 shutdown if the temperature of the component cooling water (CCW) inlet flow to the spent fuel pool heat exchanger is ≤ 95 °F. If CCW inlet flow temperature exceeds 95 °F, initiation of core offload is restricted to ≥ 168 hours after shutdown.

The reload analysis for Cycle 24 reload design was performed by FPL and AREVA-NP using NRC approved methodologies. The analyses for Cycle 24 reload support a Departure from Nucleate Boiling Ratio (DNBR) limit at the 95/95 probability/confidence level, consistent with the applicable DNB correlation previously approved by the NRC. The analyses also support the linear heat rate limit corresponding to the fuel centerline melt. All analyses in support of this EC-DCP support a maximum steam generator tube plugging level of 15% average, with a maximum asymmetry of ± 7% about the average.

The reconfiguration of the core directly affects its behavior and the capability to assure integrity of the reactor coolant pressure boundary, the capability to shutdown the reactor and/or maintain it in a safe condition, and the capability to mitigate the consequences of design basis accidents. This EC-DCP is, therefore, classified as Safety Related. The implementation of this EC-DCP will not adversely impact the safety of the plant or its operation.

During the Unit 1 Cycle 20 refueling outage, it was discovered that excore detector #7 was not in its normal operating position.

The as-found position of detector #7 is approximately 10 degree azimuthal and 3 inch radial shift away from its normal operating position. The reload analysis for Cycle 24 supports plant operation with the linear range detector # 7 position in either the as-found or the normal operating position. As such, any change in the detector replacement strategy can be handled via a revision to this EC-DCP.

The Startup Test Activity Reduction (STAR) program for St. Lucie Unit 1 allows an option to eliminate rod worth measurements during zero power physics test, following refueling. The elimination of moderator temperature coefficient measurement at hot zero power is currently not implemented at St. Lucie Unit 1 as part of the STAR program. The objective of the STAR program is to reduce startup testing operations while ensuring that the core can be operated as designed, and startup evolution following STAR would use normal operating procedures. Cycle specific STAR implementation requires verification of compliance to the STAR applicability requirements for core design, fabrication, refueling, startup testing and CEA lifetime prior to implementation. If compliance is not verified, the performance of the rod worth measurement test during the zero power physics test (ZPPT), in accordance with the approved procedures, is required. Attachment 21 provides checklists for use in the verification. For Cycle 24, per completed core design verification checklist (contained in Attachment 21), rod worth measurements will be required at zero power during the startup.

The discussions within this EC, along with the 10 CFR 50.59 Screening and Evaluation justify that the design and operation of the Cycle 24 reload core will meet the 10 CFR 50.59 (c)(2) criteria. The core reload activities can be implemented with no changes to the St. Lucie Unit 1 Technical Specifications. The safety analyses results are within the acceptance limits provided by the USNRC regulatory criteria and within the criteria provided by 10 CFR 50.59. Therefore, prior NRC approval is not required for implementation of this EC-DCP for operation in all Modes.