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Docket No.: 50-389

Dr. Robert E. Uhrig, Vice President
Advanced Systems & Technology
Florida Power & Light Company
P. O. Box 529100
Miami, Florida 33152

Dear Dr. Uhrig:

SUBJECT: ST. LUCIE PLANT, UNIT 2 FSAR - REQUEST FOR ADDITIONAL INFORMATION

From the review of your application for an operating license by the Reactor Systems Branch, we find that we need additional information regarding the St. Lucie Plant, Unit 2 FSAR. The specific information (which was provided to Mr. Dotson on 6/9/81) required is listed in the Enclosure.

Responses to the enclosed request should be submitted by July 10, 1981. If you cannot meet this date, please inform us within seven days after receipt of this letter of the date you plan to submit your responses.

Please contact Mr. Nerses (301-492-7468), St. Lucie 2 Project Manager, if you desire any discussion or clarification of the enclosed report.

Sincerely,

Original signed by
Robert L. Tedesco

Robert L. Tedesco, Assistant Director
for Licensing
Division of Licensing

Enclosure:
As stated

cc: See next page.

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DATE	6/22/81	6/22/81	6/ 2/81				

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

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ST. LUCIE

JUN 24 1981

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REQUEST FOR ADDITIONAL INFORMATION - OL FSAR
DOCKET NO. 50-389

ST. LUCIE 2 JUN 24 1981

440.0 REACTOR SYSTEMS BRANCH

440.1 (5.2.2) Appendix 5.2A of the FSAR presents the overpressure protection system for the St. Lucie unit 2 plant. Certain aspects of the analysis presented in that section do not meet staff requirements. These deficiencies should be corrected and their correction incorporated in an amendment to this appendix. The deficiencies are described below:

1: On page 5.2A-3 it is indicated at a negative doppler coefficient of $-.8 \times 10^{5}$ is utilized in the bounding overpressure transient (loss of Load). It is the staff's position that overpressure protection of the system be demonstrated with no credit taken for either doppler or moderator temperature reactivity feedback (SRP 5.2.2, Section III.6). Reanalyze the bounding overpressure transient without credit for doppler feedback, demonstrating that primary system pressure does not exceed 110% of design.

2: On page 5.2A-4, last paragraph, it indicates that the overpressure analysis was conducted assuming reactor trip due to high pressurizer pressure trip. It is the staff's position that reactor trip must be initiated either by the high pressure signal or by the second signal from the reactor protection system, which ever is later. Since the above referenced page states that high pressure trip is the first signal, your analysis is not in compliance with staff requirements. Reanalyze the event using the second trip signal (steam generator low level) demonstrating that the acceptance criteria given in Part II of SRP section 5.2.2 are met.

3: Provide details of your proposed preoperational and initial startup test program to show that they are consistent with the intent of Regulatory Guide 1.68.

4: The FSAR does not present any details of your plan to install a system which will protect the RCS from water solid/low temperature overpressurization. The staff requires that a permanent low temperature overpressure mitigation system be provided to prevent reactor vessel pressures in excess of those allowed in Appendix G. Specific criteria for system performance are:

a) Operator Action: No credit can be taken for operator action for 10 minutes after the operator is aware of a transient.

b) Single Failure: The system must be designed to relieve the pressure transient given a single failure in addition to the failure that initiated the pressure transient.

c) Testability: The system must be testable on a periodic basis consistent with the system's employment.

d) Seismic and IEEE 279 Criteria: Ideally, the system should meet seismic Category 1 and IEEE 279 criteria. The basic objective is that the system should not be vulnerable to a common failure that would both initiate a pressure transient and disable the overpressure mitigating system. Such events as loss of instrument air and loss of offsite power must be considered.

5: An alarm must be provided to monitor the position of the pressurizer relief valve isolation valves to assure that the overpressure mitigating system is properly aligned for shutdown conditions.

In demonstrating that the mitigation system meets these criteria, the applicant should include the following information in his submittal:

1. Identify and justify the most limiting pressure transients caused by mass input and heat input.

2. Show that overpressure protection is provided (do not violate Appendix G limits) over the range of conditions applicable to shutdown/heatup operation.

3. Identify and justify that the equipment will meet pertinent parameters assumed in the analyses, (e.g., valve opening times, signal delay, valve capacity).

4. Provide a description of the system including relevant P&I drawings and electrical schematics.

5. Discuss how the system meets the criteria.

6. Discuss all administrative controls required to implement the protection system.

The following comments should be considered by the applicant in their response to this question:

1. The limiting design basis transients are not discussed in sufficient detail. Additionally, the design basis energy input case assumed an inactive coolant loop delta T of 100°F. This selection must be defined as appropriately conservative, and administrative controls established to assure that this limit is not exceeded. This limitation should be included in the plant technical specifications. Also, consider the possibility of a transient initiated by the start of more than one RCP.

2. Provide details of and electrical diagrams for the PORV actuation circuitry, for situations when the system is aligned in the low temperature mode.

3. Provide details of the PORV relief rates assumed in the transient analysis, and document the tests and analysis used to verify these assumptions. The verification should encompass relief under both single phase and two phase conditions as well as steam relief. Address your participation in the EPRI valve test program.

440.2 Consider all structures, systems and components which are shared between the two units, and identify where this commonality exists. It is the staff's position per GDC 5 that structures, systems and components important to safety shall not be shared among units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions. Document your compliance with the above position.

440.3
(5.4.7) St. Lucie unit #2 must have the capability to take the plant from full power to a cold shutdown using only safety grade equipment, per the requirements of BTP RSB 5-1. Address your compliance with all provisions of that position and respond to the detailed questions below..

1. Describe the sequence for achieving a cold shutdown condition within 36 hours, assuming the most limiting single failure with only onsite power available. Identify all manual actions inside or outside containment that must be performed and discuss the capability of remaining at hot standby until manual actions (or repairs) can be performed.

   a. Describe the sequence for depressurizing the primary system using only safety-grade systems, assuming a single failure. Identify all manual actions inside or outside containment that must be performed.

   b. Discuss the boration capability using only safety-grade systems, assuming a single failure. Identify all manual actions inside or outside containment that must be performed. If the proposed boration method utilizes the charging pumps (assuming a letdown line failure is proposed), provide an evaluation of this approach with regard to concentration of boron source and liquid volume in primary system.

2. Discuss the provisions for collection and containment of RHR pressure relief valve discharge.

3. Describe tests which will demonstrate adequate mixing of the added borated water and cooldown under natural circulation conditions with and without a single failure of a steam generator atmospheric dump valve. Specific procedures for plant cooldown under natural circulation conditions must be available to the operator. Summarize these procedures.

4. Discuss the availability of a seismic Category I auxiliary feedwater supply for at least 4 hours at hot shutdown plus cooldown to the RHR system entry based on the availability of only onsite or only offsite power and assuming a single failure. If this cannot be achieved, discuss the availability of an adequate alternate seismic Category I water source.

5. What provisions for natural circulation cooldown methods have been made to account for possible upper head void formation. If these provisions result in a slower cooldown rate when in natural circulation, verify that sufficient quantities of seismic condensate water are still available.

440.4 (5.4.7) Provide detailed information on the sizing criteria used to determine the relief capacity of the SDCS suction line pressure relief valves. Did the version of the ASME Code that the SDCS relief valves were designed to require establishing liquid or two-phase relief capacity with testing? If so, describe in detail the test program and results. If the liquid or two-phase relief capacity was not established by test, show that the difference between the rated and maximum required relief capacity is more than sufficient to bound liquid and two-phase relief rate uncertainties.

440.5 (5.4.7) Provide details on the alarms and indications which would inform the operators that a SDC suction line isolation valve has closed while the plant is in shutdown cooling. Is there any common failure which would result in both valves being closed while in shutdown cooling.

When LPSI pump mini flow isolation valves are closed during shutdown cooling, what would prevent pump damage if a pressure transient were to occur which causes RCS pressure to exceed LPSI deadhead pressure? It is the staff's position that instrumentation and alarms be available to call for operator action prior to pump damage. When the plant is in the SDCS mode, is there any single failure which could cause the suction of both SDC pumps to be switched from the hot leg piping to the dry sumps?

440.6 (5.4.7) Indicate whether there are any systems or components needed for shutdown cooling which are de-energized or have power locked out during plant operation. If so, indicate what actions have to be taken to restore operability to the components or systems. It is the staff's position that all operator actions necessary to take the plant from normal operation to cold shutdown (SDCS entry) should be performed from the control room. If the present design does not meet this position, please commit to revise it accordingly.

440.7 (5.4.7) Provide the following information related to pipe breaks or leaks in high or moderate energy lines outside containment associated with the RHR system when the plant is in a shutdown cooling mode:

1. Determine the maximum discharge rate from pipe break for the systems outside containment used to maintain core cooling.

2. Determine the time frame available for recovery based on these discharge rates and their effect on core cooling.

3. Describe the alarms available to alert the operator to the event, the recovery procedures to be utilized by the operator; the time available for operator action.

A single failure criterion consistent with Standard Review Plan 3.6.1 and Branch Technical Position APCSB 3-1 should be applied in the evaluation of the recovery procedures utilized.

440.8 (15.0) Table 15.0-4 provides the staff no quantitative basis upon which to evaluate your plant. Modify this table to include the numerical values which are applicable to St. Lucie unit 2. Justify your quantification.

440.9 All events analyzed in chapter 15 are designed to challenge the capability of the protection and engineered safeguards systems to maintain the fuel, pressure, and radiological release within prescribed limits, dependent upon the event category. For each event analyzed in chapter 15 with a concurrent single active failure, justify why the single active failure selected is considered the worst case with respect to challenging the fuel, pressure, and radiological release limits.

440.10 (15.0) Confirm that during the preoperational or startup test phase you intend to verify the valve discharge rates and response times (such as opening and closing times for main feedwater, auxiliary feedwater, turbine and main steam isolation valves, and steam generator and pressurizer relief and safety valves) to show that they have been conservatively modeled in the Chapter 15.0 analyses.

440.11 (15.0) The method that you have used for calculating the amount of failed fuel after an accident has not been approved. It is our position that fuel failures be recalculated using the criteria that any fuel rod which has a CE-1 DNBR less than the minimum DNBR value determined in Section 4.4 fails. Radiological consequences should be calculated accordingly.

440.12 (15.0) Verify that for each transient analyzed in Chapter 15, if operator action is not discussed then no operator action is required. In particular, consider events in which the ECCS is actuated or RCP trip would be required based on present procedures.

If operator action is anticipated regardless of whether or not it is required, discuss this action and its impact on the consequences. Include a discussion of the potential for operator error.

440.13 (15.0) For each accident, discuss non-safety grade equipment which was assumed to operate and could result in the transient becoming more severe or verify that no non-safety grade equipment operating would produce a more severe transient. For example, the pressurizer heaters being energized for a transient resulting in high RCS pressures could tend to worsen the effects of the transient. Likewise, pressurizer spray could be detrimental for a transient resulting in low RCS pressure.

440.14 (15.0) For non-LOCA transients, minimum DNBR (departure from nucleate boiling ratio) is of primary importance. For those transients analyzed in Section 15 of the FSAR, provide graphical output of the DNBR as a function of time.

440.15 (15.2.1) Section 15.2.1.2.1 states that turbine isolation is the most limiting event of those shown on Table 15.2.1-1, since it results in the largest energy imbalance. Demonstrate that this event is limiting with respect to peak RCS pressure and minimum DNB, or provide separate analysis for each event in the Table. Provide the minimum DNB for the Turbine isolation event, and show where in the transient it occurs.

440.16 (15.2.1) Section 15.2.1.2.4 indicates that the turbine isolation transient was evaluated at two percent power, while in section 15.2.1.2.2 (page 15.2-32) it states that the analysis was performed at 100 percent power. Which is correct? If the analysis was performed at 100 percent power, how does it account for possible instrument uncertainties in power level.

440.17 (15.2.2.1) For the turbine trip transient discussed in this section, what are the consequences if the operator does not manually trip the reactor at 600 seconds? How would the scenario change?

440.18 (15.2.2.1) Discuss the system used to provide pressurizer heater cutoff on low level. Is there any single failure that could result in the heaters remaining energized while uncovered? If so, discuss the consequences of this occurrence. In your answer, you may wish to consider the event which occurred at the Spert III facility in Idaho, where a pressurizer was heated to a point where it lost integrity.

440.19 (15.2.2) In this section, you have provided the loss of condenser vacuum with a fast transfer failure and technical specification steam generator tube leakage as the limiting RCS pressure and the limiting radiological release event for the limiting fault event category in the decreased heat removal by secondary system group. Although these limiting cases may be the candidates for the limiting cases for the infrequent event category in the group, they were not selected by a qualitative comparison of similar initiating events plus a single failure specified in SRP 15.2.1 through 15.2.7. Provide a qualitative analysis in the FSAR for each of the initiating events plus a single failure in the same group per the SRP, and identify the limiting cases for the group. Provide a detail quantitative analysis for each of the limiting cases including the limiting RCS pressure, limiting fuel performance, and the limiting radiological release. Confirm that the results of the analyses meet the acceptance criteria for these events per SRP 15.2.1.

440.20 The event analyzed in Section 15.2.3.2, Loss of Condenser Vacuum results in a peak pressure which is above the 110 percent of design (2485 psi) pressure. Since you state that loss of offsite power is a consequential failure for this event, we find the results inconsistent with the criteria of the SRP for anticipated transients and, therefore, unacceptible. We require that this event, analyzed with all consequential failures, and including a stuck rod assumption per GDC 26, results in a calculated peak primary system pressure less than 110 percent of the design pressure.

440.21 (15.2.3) On page 15.2-116 it states that charging control valves are to be manually closed to divert flow to the auxiliary sprays. Are these valves power actuated? If so, can they be operated following loss of offsite power?

440.22 (15.3) Provide tabulations of the sequence of events, disposition of normally operating systems, utilization of safety systems, and a transient curve of primary system pressure for the total loss of primary coolant flow event. Also provide an analysis of the total loss of primary coolant flow with a single failure event. Confirm that the results of these analyses meet the acceptance criteria for these events per SRP 15.3.1.

440.23 (15.3.2) For loss of AC or other events where charging pumps are needed, how are the charging pumps loaded onto safety buses? Can this be accomplished from the control room; if not, how much time is required to perform necessary actions?

440.24 (15.3.2) Describe all auxiliary functions such as lubrication, cooling and control air which are lost upon loss of offsite power. Demonstrate that their unavailability will not compromise plant safety. If RCP component cooling or thermal barrier water is lost in this situation, evaluate the ability of the RCPs to maintain seal integrity for extended periods of time.

440.25 (15.3.3) Provide a detailed analysis of the consequences of a RCP shaft seizure event. Justify your selection of limiting single failures, per the concern expressed in 440.9. The time at temperature studies which justify your claims of peak clad temperature being limited to 1300°F are not accepted by the staff. In assessing fuel failures, any rod which experiences a DNBR of less than 1.19 must be assumed failed. Confirm that the results of the analysis meet the acceptance criteria of SRP 15.3.3. Provide your assumptions on flow degradation due to the locked rotor in the faulted loop, and reference appropriate studies which verify these assumptions. Also indicate whether Tech Spec SG tube leakage was assumed, and if loss of offsite power was postulated for the event. Also provide a similar analysis for the locked rotor event presented in section 15.3.4.1, and show that acceptable consequences result.

440.26 (15.3.3) Provide results of an analysis of the reactor coolant pump shaft break as required by SRP 15.3.4 for staff review. The event should consider loss of offsite power following turbine trip and with technical specification steam generator tube leakage. The criteria stated in Question 440.11 should be used for the calculation of the amount of failed fuel for this event. State the amount of failed fuel in the results of the analysis. Radiological consequences should be calculated accordingly. Confirm that the results of the analysis meet the acceptance criteria for these events per SRP 15.3.4 which classifies this event as an infrequent event.

440.27 (15.4.2) In discussing boron dilution events, section 15.4.2.4.3 assumes a minimum RCS water volume of 9777 ft^3 and boron criticality value of 845 ppm. Justify the selection of these values. What procedures assure that a 2% shutdown margin is maintained during mode 5?

440.28 (15.4.2) Your FSAR indicates that operational procedures allow detection of a boron dilution event 15 minutes prior to criticality. This is not acceptable. The staff will require that alarms be available to alert the operator to a boron dilution transient 15 minutes prior to criticality (30 minutes when in refueling mode). Show that the plant is protected for all postulated boron dilution events assuming the worst single active failure. In particular, consider the failure of the first alarm. If a second alarm is not provided, show that the consequences of the most limiting unmitigated boron dilution event meet the staff criteria and are acceptable. Also, indicate for all six modes what alarms would identify to the operators that a boron dilution event was occurring. Confirm that the results of these analyses meet the acceptance criteria for these events per SRP 15.5.1.

440.29 (15.5.3) Section 15.5.3 discusses transients which result in RCS inventory increases. These rely on operator action following high pressurizer level alarm. Provide information on the high pressurizer level alarm. Is this a safety grade alarm? What are the consequences if the operator does not terminate charging flow within 21 minutes for the increasing RCS inventory transient discussed in this section? In addition, provide a detailed quantitative analysis for each of the limiting cases of RCS inventory increase, including the limiting RCS pressure, limiting fuel performance and the limiting radiological release. Confirm that the results of the analysis meet the acceptance criteria for these events per SRP 15.5.1.

440.30 (1.9A) Your response to NUREG-0737 item II.B.1 indicates that the design for the reactor coolant system vents will be provided later. When will this information be available? This system must be in place prior to license issuance, and your license will be conditioned if necessary.

440.31 (1.9A) Your response to NUREG-0737 item I.K.1 is not sufficient. Procedures dealing with all safety related systems and components must require independent verification of all valve operations and breaker positions, both for operational safeguards readiness and for realignment for the performance of maintenance or tests. At the completion of maintenance or tests, the same independent verification must be performed for the restoration portion of the procedure to assure the operability status. Periodic tests and checks must also be performed to verify continued operability status. Modify your response to I.K.1 to include these commitments.

440.32 (1.9A) Your responses to items II.K.2.13 and II.K.2.17 of NUREG-0737 indicates that generic evaluations performed by CE "may" be prepared. You must commit to submitting a suitable generic analysis, or a plant specific analysis prior to fuel loading. The present commitment is too ambiguous in nature.

440.33 (1.9A) You have not provided the information required by NUREG-0737 items II.K.3.1 and II.K.3.2. Until such information is provided, the staff is unable to make any evaluation upon the St. Lucie PORV isolation system. Please provided the necessary information.

440.34 (1.9A) You have not responded to NUREG-0737 item II.K.3.17. Please provide this information.

440.35 (1.9A) In your response to NUREG-0737 item II.I.3.25, you indicated that FP&L has conducted tests of RCP seals under simulated loss of AC power. Provide details regarding the test. Were the seals tested new or at expected wear limits? Were post test inspections of the seals conducted? What were the results?

440.36 (1.9A) Your response to NUREG-0737 item II.K.3.30 does not provide the necessary commitment to submit a report justifying the adequacy of the present small break LOCA model. Provide this commitment and your submittal schedule.

440.37 (1.9A) Your response to NUREG-0737 item II.K.3.31 should include a commitment to submit, within one year after staff approval of the SBLOCA models discussed above, a revised small break ECCS analyses.

440.38 (6.3) Discuss the provisions and precautions for assuring proper system filling and venting of ECCS to minimize the potential for water hammer and air binding. Address piping and pump casing venting provisions and surveillance frequencies.

440.39 (6.3) Identify all ECCS valves that are required to have power locked out confirm they are included under the appropriate Technical Specifications, with surveillance requirements listed.

440.40 (6.3) Consideration should be given to the possibility that local manual valves (handwheel), could go undetected in the wrong position until a postulated accident occurs. Appropriate administrative controls or valve position indication are examples of methods to be considered to minimize this possibility. Provide a list of all critical manual valves and address the actions that will be implemented to assure all critical valves are properly positioned.

Identify all manual valves which have locking provisions.

It is our position that limit switches which enable valve position to be indicated in the control room should be installed on all manually operated and normally locked ECCS valves.

In addition a recent event (Docket 50-320, LER 78-20/3L, 4/21/78) has brought to our attention that the automatic operation of some motor operated valves can be disabled when the manual handwheel pins are engaged. Identify all critical motor operated valves associated with the St. Lucie design that have this design feature and describe the controls and procedures utilized to prevent the inadvertent disablement of the automatic operation of these valves.

440.41 (6.3) Identify the plant operating conditions under which certain automatic safety injection signals are blocked to preclude unwanted actuation of these systems.

Describe the alarms available to alert the operator to a failure in the primary or secondary system during this phase of operation and the time available to mitigate the consequences of such an accident.

440.42 (6.3) The information in the St. Lucie 2 regarding post-LOCA passive failures is not complete. It is the Reactor Systems Branch position that detection and alarms be provided to alert the operator to passive ECCS failures during long-term cooling which allow sufficient time to identify and isolate the faulted ECCS line. The leak detection system should neet the following requirements:

(1) Identification and justification of maximum leak rate should be provided.

(2) Maximum allowable time for operator action should be provided and justified.

(3) Demonstration should be provided that the leak detection system will be sensitive enough to initiate (by alarm) operator action, permit identification of the faulted line, and isolation of the line prior to the leak creating undesirable consequences such as flooding of redundant equipment or excessive radioactive fluid. The minimum time to be considered is 30 minutes.

(4) It should be shown that the leak detection system can identify the faulted ECCS train and that the leak is isolatable.

(5) The leak detection system must meet the following standards:

a. Control Room Alarm
b. IEEE 279-1971. except single failure requirements

440.43 (6.3) The acceptance criteria in the Standard Review Plan for Section 6.3 states the ECCS should retain its capability to cool the core in the event of a single active or passive failure during the long-term recirculation cooling phase following an accident. Demonstrate that St. Lucie 2 ECCS design has this capability.

440.44 (6.3) A reported event has raised a question related to the conservatism of NPSH calculations with respect to whether the absolute minimum available minimum available NPSH has been considered. In the past, the required NPSH has been taken by the staff as a fixed number supplied through the applicant by either the architect engineer or the pump manufacturer. Since a number of methods exist and the method used can affect the suitability or unsuitability of a particular pump, it is requested that the basis on which the required NPSH was determined be branded (i.e., test, Hydraulic Institute Standards) for all the ECCS pumps and the estimated NPSH variability between similar pumps including the testing inaccuracies be provided.

440.45 (6.3) Provide the basis for ECCS lag times. Are these times calculated or verified by test? If calculated, are they verified during preoperational tests, and periodically reverified?

440.46 (6.3) Provide in the Technical Specifications, (1) the range of nitrogen cover gas pressure for the SIT, and (2) the ECCS pump discharge pressures.

440.47 (6.3) Provide a time reference for each action in the sequence of action included in the changeover from injection to recirculation. Indicate the time required to complete each action and what other duties the operator would be responsible for at this point in the accident. How much time does the operator have to assure that the system is realigned to the recirculation mode before RWST water is exhausted if the RWST isolation valves are not closed? Consider the required pump NPSH in your response.

If the operator fails to close the RWST isolation valves, demonstrate that the HPSI will continue to adequately cool the core during the recirculation mode.

440.48 (6.3) Recently, another plant has indicated that a design error existed in the sizing of their RWST. This error was discovered during a design review of the net positive suction head requirements for the containment spray and residual heat removal pumps. The review showed that there did not app ear to be sufficient water in the RWST to complete the transfer of pump suctions from the tank to the containment sump, before the tank was drained and ECCS pump damage occurred.

It was reported that in addition to the water volume required for injection following a LOCA, an additional volume of water is required in the RWST to account for:

(1) Instrument error in RWST level measurements.

(2) Working allowance to assure that normal tank level is sufficiently above the minimum allowable level to assure satisfaction of technical specifications.

(3) Transfer allowance so that sufficient water volumne is available to supply safety pumps during the time needed to complete the transfer process from injection to recirculation.

(4) Single failure of the ECCS system which would result in larger volumes of water being needed for the transfer process. In this situation, the worst single failure appears to be failure of a single ECCS train to realign to the containment sump upon low RWST signal. This result in the continuation of large RWST outflows and reduces the time available for the manual recirculation switchover, before the tank is drawn dry and the operating ECCS pumps are damaged.

(5) Unusable volume in the tank is present because once the tank suction pipes are reached, the pumps lose suction and any remaining water is unusable. Additionally, some amount of water above the suction pipes may also be unusable due to NPSH considerations and vortexing tendencies with the tank.

Preliminary indications are that approximately an additional 100,000 gallons of RWST capacity were needed to account for these considerations. It is our understanding that the design parameters for instrument error, transfer allowance and single failure have changed since the original sizing of the tank.

In light of the above information, discuss the adequacy of your Refueling Water Storage Tank. Provide a discussion of the necessary water volumes to accommodate each of the five considerations indicated above. Justify your choice of volumes necessary to account for each consideration. Provide drawings of your RWST, showing placement and elevation of tank suction lines, and level sensors. Also, provide operator switchover procedures for aligning to the recirculation mode, with estimates of the time required for each action.

440.49 (6.3) Provide a discussion on specific methods of detecting, alarming and isolating passive ECCS failures during long term cooling to include valve leakage. Show that there is sufficient time for the operator to take corrective action and maintain an acceptable water inventory for recirculation. Justify the basis for the assumed leak rates. Describe how the contaminated water would be handled if one ECCS train must continue to operate with a leak.

440.50 (6.3) Assume a maximum passive failure flow rate of 50 GPM in each ECCS pump room and discuss the effects of the passive failure to each ECCS pump operation and demonstrate that adequate protection is provided for ECCS pumps from possible flooding.

440.51 (6.3) In the event of early manual reset of the safety injection actuation signal (SIAS) followed by a loss of offsite power during the injection phase, operator action may be required to reposition ECCS valves and restart some pumps. The staff requires that operating procedures specify SIAS manual reset not to be permitted for a minimum of 10 minutes after a LOCA. Provide the administrative procedures to ensure correct load application to the diesel generators in the event of loss of offsite power following an SIAS reset.

440.52 (6.3) Describe the instrumentation for level indication in the containment emergency sump. Also, provide detailed design drawings of the containment emergency sump including the design provisions which preclude the formation of air entraining vortices during recirculation cooling. Confirm that the containment emergency sump design meets the requirements of Regulatory Guide 1.82.

440.53 (6.3) Recent plant experience has identified a potential problem regarding the operability of the pumps used for long-term cooling (normal and post-LOCA) for the time period required to fulfill that function. Provide the pump design lifetime (including operational testing) and compare to the continuous pump operational time required during the short and long term of a LOCA. Submit information in the form of tests or operating experience to verify that these pumps will satisfy long-term requirements.

440.54 (6.3) Describe the means provided for ECCS pump protection including instrumentation and alarms available to indicate degradation of ECCS pump performance. Our position is that suitable means should be provided to alert the operator to possible degradation of ECCS pump performance. All instrumentation associated with monitoring the ECCS pump performance should be operable without offsite power, and should be avle to detect conditions of low discharge flow.

440.55 Describe the instrumentation available for monitoring ECCS performance during post-LOCA operation (injection mode and recirculation mode).

440.56 (6.3) Provide a commitment that St. Lucie 2 will perform preoperational and startup tests to meet the requirements of Regulatory Guide 1.68,1.79.

440.57 (6.3) Provide a commitment that St. Lucie 2 will perform tests of ECCS as installed to confirm that the actual ECCS flow rates are greater than the values assumed in the LOCA analyses.

440.58 (6.3) List all ECCS valve operators and controls that are located below the maximum flood level following a postulated LOCA or main stream line break. If any are flooded, evaluate the potential consequences of this flooding both for short and long-term ECCS functions and containment isolation. List all control room instrumentation lost following these accidents.

440.59 (6.3) If it is our position that the SIS hotleg injection valves should be locked closed with power removed during normal plant operation in order to prevent premature hotleg injection following a LOCA.

440.60 (6.3) Your sump test program described in Section 6.2.2 is not in sufficient details. The experimental program must demonstrate that there is sufficient margin in available NPSH over that required for each pump with all pumps at runout or maximum post-LOCA flow.

The test must demonstrate that the design precludes conditions adverse to safety system operation. Test parameters must include: (1) minimum to maximum containment water level, (2) minimum to maximum safety system flow range in various combonations (this includes transients associated with start-up, shutdown, or throttling of a train or pump), (3) random blockage of up to 50 percent of the screens and grids, (4) approach flow for each dominant direction and combinations thereof, and (5) simulation of break flow or drain flow impinging or originating withing line of sight of the sump and its approaches.

If adverse conditions are encountered, the model configuration must be revised until an acceptable configuration is developed and demonstrated to perform over the full range of variables.

Since you choose to conduct a model test, provide details of the test program. Include information on the model size, scaling principles utilized, comparison of model parameters to expected post-LOCA conditions, and a discussion on how all possible flow conditions and screen blockages will be considered in the model tests. Whenever a reduced scale model is tested all tendencies for vortex formation must be suppressed. Rotational flow patterns and surface dimples which might be acceptable in full scale tests, probably would not be accepted in a model program. Model testing must include some in-plant testing to demonstrate experimentally that NPSH margin exists for each pump.

440.61 (6.3) During our reviews of license applications we have identified concerns related to the containment sump design and its effect on long term cooling following a Loss of Coolant Accident (LOCA).

These concerns are related to (1) creation of debris which could potentially block the sump screens and flow passages in the ECCS and the core, (2) inadequate NPSH of the pumps taking suction from the containment sump, (3) air entrainment from streams of water or steam

which can cause loss of adequate NPSH, (4) formation of vortices which can cause loss of adequate NPSH, air entrainment and suction of floating debris into the ECCS and (5) inadequate emergency procedures and operator training to enable a correct response to these problems. Preoperational recirculation tests performed by utilities have consistently identified the need for plant modifications.

The NRC has begun a generic program to resolve this issue. However, more immediate actions are required to assure greater reliability of safety system operation. We therefore require you take the following actions to provide additional assurance that long term cooling of the reactor core can be achieved and maintained following a postulated LOCA.

1. Establish a procedure to perform an inspection of the containment, and the containment sump area in particular, to identify any materials which have the potential for becoming debris capable of blocking the containment sump when required for recirculation of coolant water. Typically, these materials consist of: plastic bags, step-off pads, health physics instrumentation, welding equipment, scaffolding, metal chips and screws, portable inspection lights, unsecured wood, construction materials and tools as well as other miscellaneous loose equipment. "As licensed" cleanliness should be assured prior to each startup.

   This inspection shall be performed at the end of each shutdown as soon as practical before containment isolation.

2. Institute an inspection program according to the requirements of Regulatory Guide 1.82, item 14. This item addresses inspection of the containment sump components including screens and intake structures.

3. Develop and implement procedures for the operator which address both a possible vortexing problem (with consequent pump cavitation) and sump blockage due to debris. These procedures should address all likely scenarios and should list all instrumentation available to the proper operator (and its location) to aid in detecting problems which may arise, indications the operator should look for, and operator actions to mitigate these problems.

4. Pipe breaks, drain flow and channeling of spray flow released below or impinging on the containment water surface in the area of the sump can cause a variety of problems; for example, air entrainment, cavitation and vortex formation.

   Describe any changes you plan to make to reduce vortical flow in the neighborhood of the sump. Ideally, flow should approach uniformly from all directions.

5. Evaluate the extent to which the containment sump(s) in your plant meet the requirements for each of the items previously identified; namely debris, inadequate NPSH, air entrainment, vortex formation, and operator actions.

The following additional guidance is provided for performing this evaluation.

(1) Refer to the recommendations in Regulatory Guide 1.82 (Section C) which may be of assistance in performing this evaluation.

(2) Provide a drawing showing the location of the drain sump relative to the containment sump.

(3) Provide the following information with your evaluation of debris:

(a) Provide the size of openings in the fine screens and compare this with the minimum dimensions in the pumps which take suction from the sump (or torus), the minimum dimensions in any spray nozzels and in the fuel assemblies in the reactor core or any other line in the recirculation flow path whose size is comparable to or smaller than the sump screen mesh size in order to show that no flow blockage will occur at any point past the screen.

(b) Estimate the extent to which debris could block the trash rack or screens (50 percent limit). If a blockage problem is identified, describe the corrective actions you plan to take (replace insulation, enlarge cages, etc.)

(c) For each type of thermal insulation used in the containment, provide the following information:

(i) type of material including composition and density,
(ii) manufacturer and brand name,
(iii) method of attachment,
(iv) location and quantity in containment of each type,
(v) an estimate of the tendency of each type to form particles small enough to pass through the tine screen in the suction lines.

(d) Estimate what the effect of these insulation particles would be on the operability and performance of all pumps used for recirculation cooling. Address effects on pump seals and bearings.

440.62 (6.3) The submittal for the LOCA analyses does not address the effects of steam generator tube plugging. The effect of a decrease in steam generator tube flow area is an increase in the peak cladding temperature (when the peak occurs during the reflood portion of the transient). If

the analyses provided are considered to support generators with plugged tubes, describe the extent of the plugging the analyses support and the method used to account for the plugging. If steam generator tube plugging was not considered, the applicant will be required to perform additional ECCS analyses prior to operation with plugged generator tubes. In either case, the applicant is required to include an interface requirement on the validity of the LOCA analyses (acceptance criteria of 10 CFR 50.46) and the Technical Specification limit for the number (or percentage) of allowable plugged steam generator tubes.

440.63 (6.3) The LOCA break spectrum submitted is incomplete. The large break spectrum does not include an analysis for the complete, double-ended guillotine break of the largest pipe in the primary coolant system (Appendix K, C.1, 10 CFR 50). The characteristic response of peak cladding temperature as a function of break size (Cd), presented by the applicant is not typical of other license submittals. In order to complete the spectrum, provide a large break LOCA analyses for a double-ended guillotine break in the hot leg and for a double-ended guillotine break in the pump section leg.

440.64 (6.3) The submittal does not provide analyses for the small break LOCA spectrum. Provide a failure modes effects evaluation of ECCS equipment for small break LOCAs. Provide the analyses for the small break LOCA spectrum, using an approved evaluation model which is in compliance with the acceptance criteria for ECCS given in 10 CFR 50.46 and Appendix K to Part 50. The analyses are to include the finding of the failure modes effects evaluation and cover a suitable range of break sizes to determine the limiting break. The spectrum is to also include breaks in the pressurizer steam region and in the reactor vessel lower head.

440.65 (6.3) For small break LOCAs, if the SIAS set point is reached, non-essential component cooling water (CCW) is isolated to containment, and CCW is no longer provided to the RC pumps. Demonstrate that the RC pump seals will remain intact and not result in an additional failure of the pressure boundary for the duration of the accident. Address the expected RC pump operations for the accident. If seal integrity cannot be maintained, seal failure must be assumed. Discuss the maximum seal leakage rate based on operating experiences. If the consequences of seal failure are assumed to be covered by the break spectrum, justify the differences in the leakage location from the locations analyzed.

440.66 (6.3) The analysis for the inadvertant opening of a pressurizer relief valve (PORV) is to be provided. The analysis is to be performed using the acceptance criteria provided in SRP 15.6.1. The results of the analysis are to be shown to be in compliance with the acceptance criteria of SRP 15.6.1. A DNBR graph is to provide in the response.

440.67 (6.3) In light of recent operating experiences (the St. Lucie Unit 1 natural circulation cool down event of June 11, 1980, and re-analyses of SAR Chapter 15 design bases events by St. Lucie in February 1981) a potential deficiency has been identified with the CESEC computer program and NSSS model. As the pressurizer cools down and the system pressure decreases, steam can form in the reactor vessel upper head due to flashing of the hot coolant in this stagnant region. The steam bubble in the reactor vessel upper head displaces coolant from the reactor vessel into the pressurizer and the steam in the vessel head will determine the system pressure. The CESEC model used for the steam generator tube rupture event does not account for this occurrence. Further, CESEC analyses which predict that the pressurizer will empty, or that the reactor coolant system saturates, do not appear to correctly calculate the system thermal-hydraulic response and are not justified for use. These events are to be re-analyzed with a suitable model or additional justification is to be provided to demonstrate that analyses performed with the CESEC computer program conservatively accounts for the formation of steam in the reactor coolant system.

440.68 (6.3) The analysis for a steam generator tube rupture does not address tube leakage in unaffected steam generator. Provide on interface requirement for the allowable steam generator tube leakage and reference the Technical Specification limit. Confirm the analyses were performed using this allowable limit, or provide justification why this leakage term can be excluded from the analyses.

440.69 (15.6.2) SRP 15.6.3 acceptance criteria requires that this event be analyzed with a concurrent loss of offsite power. Provide an analysis for the limiting case which includes a concurrent loss of offsite power.

440.70 (15.6.2) Provide the justification used to determine that the operator isolates the faulted steam generator in 22 minutes. Operational data should be cited as part of the justification. In particular, you should address the conclusions of NUREG-0651 (Evaluation of Steam Generator tube rupture events). If adequate justification cannot be provided, an assessment of the dose rates using a justifiable time for operation action is required.

440.72 (15.6.2) For the SGTR event, what prevents steam from the affected steam generator being used to drive the steam-driven auxiliary feedwater pump and exhausted to the environment? If operator action is required, confirm that no credit for operator action was given, consistent with your assumption of the time required for the operator to isolate the affected steam generator. If credit was given for the operator to secure the steam supply to the steam driven AFW pump in less than that assumed for operator action to isolate the faulted generator, provide justification why this credit can be given, or reanalyze the event assuming steam from the faulted steam generator is used to drive the steam-driven AFW pump and is exhausted to the environment.

440.73 (15.6.3, 15.6.4, 15.6.5) Provide a description of the analyses or the evaluations used to determine the limiting events for these categories. The events listed are not consistent with those presented by other licensees for the same categories, and appear to be less limiting than, for example, a break in the letdown line outside containment.

440.74 (15.6.3, 15.6.4, 15.6.5) Discuss the single failure assumed for these analyses. What analyses/evaluations were performed to justify that the single failures chosen were the most limiting?

440.75 (15.1.2) The overcooling transients analyzed in Chapter 15 (excluding the steam line break events) were assessed utilizing the CESEC-II computer program. This program does not properly account for steam formation in the reactor vessel and in the primary system after the pressurizer empties. CESEC-II is also incapable of evaluating asymmetric cooldown (i.e., independent hot leg temperature between the broken and intact loops). Neglecting these effects can result in the improper evaluation of the system pressure and hydraulic behavior. The modeling deficiency in CESEC-II has the potential for providing unacceptable results for depressurizing transients. As such, for transients which empty the pressurizer or result in saturated coolant conditions at other locations in the primary system, the CESEC-II computer program must be verified to correctly calculate system thermal - hydraulic responses. The staff requires that these events be reanalyzed with a suitable model or additional justification be provided in order to demonstrate the acceptability of the CESEC-II program to predict the thermal - hydraulic phenomena in question, and to demonstrate compliance with NRC regulations.

440.76 (15.1.2) The following questions relate to increased feedwater flow with a failure to achieve a fast transfer of a 4.16 KV bus:

(a) What was the minimum DNBR for this event?

(b) The analysis assumed nominal primary to secondary leakage through the steam generator tubes of 20 gallons/day. Reanalyze this event utilizing a leakage rate equal to the technical specification limits utilizing a suitable model.

(c) Reanalyze this transient assuming a stuck CEA, as required by the SRP and applicable GDC's (i.e., GDC-26).

(d) Section 15.1.2 states that the increase in main steam flow through the turbine will not cause a reactor trip, and therefore, will not result in steam releases to the atmosphere. This event was therefore not analyzed. Verify that this event will not exceed any fuel design limits as well.

440.77 (15.1) Section 15 addresses operator actions required to bring the reactor system to cold shutdown. Based on the St. Lucie Unit 1 natural circulation cooldown event of 1980, update the operator actions to include any precautions and modifications resulting from the St. Lucie Unit 1 event to prevent voiding in the upper head of the reactor vessel.

440.78 (15.1) It is our understanding that the majority of the Section 15 transients were evaluated without the assumption of a stuck CEA in the fully withdrawn position. If this is the case, then we require all analyses to be reevaluated with the most reactive CEA withdrawn, consistent with the requirements of General Design Criteria 26 and the SRP criteria.

440.79 (15.1) The loss of main steam with loss of offsite power event is predicted to result in 7.6 percent fuel damage for St. Lucie 2. This limiting analysis was for a 2.27 sq ft break area, versus a double-ended guillotine break (DEGB) of 6.3 sq ft. Address the reasons why this event is limited by a small steam line break for St. Lucie while the limiting break for Waterford was analyzed to be a DEGB. Also address the reasons for the St. Lucie clad failure predictions whereas the Waterford analyses did not predict clad damage.

440.80 (15.1) The following concerns address sections 15.1.4 and 15.1.5:

(a) Present operator guidelines require manual trip of the reactor coolant pumps upon ECCS initiation. Moreover, the Standard Review Plan requires the assumption of loss of off-site power during a postulated steam line break accident. These requirements, along with automatic initiation of the auxiliary feedwater system, have not been addressed in the FSAR. Reanalyze those transients and accidents for which the tripping of the reactor coolant pumps could influence the outcome of the event and assess the consequence of losing offsite power during the steam line break event.

(b) Address the consequences of steam line breaks at near zero or zero power conditions, whichever is limiting. SRP 15.1.5 requires this assessment.

(c) Figure 15.1.4.3-2 is a graph of core power versus time for the steam line break analysis. This figure lists "Core Power, Percent of 2560 MWT." Verify that the analysis was performed with a core thermal power of 2630 MWT, as listed in Table 15.1.4.3-4.

(d) The steam line break analyzed was a 2.27 ft^2 break opening, versus 6.3 ft^2 (DEGB). Verify, utilizing an appropriate analysis model, that a 6.3 ft^2 break would not be limiting when early auxiliary feedwater initiation is assumed.

(e) Figure 15.1.4.3.-12 indicates greater steam flow exiting the intact steam generator versus the broken steam generator line. Please explain

(f) For the steam line break analyses, provide individual plots of the ECCS flow rates for the HPI, Charging Pumps, the Safety Injection Tanks, and LPSI, if initiated.

(g) Loss of off-site-power should not be considered a single failure when assessing steam line breaks. It is our understanding that for the steam line break analyses, loss of off-site-power was assumed as the single failure. If this is the case, then we require a reanalysis of the steam line break event with the limiting break event with the limiting single failure, other than loss of off-site-power.

(h) The limiting Fault 2 event was a steam line break concurrent with a failure to achieve a fast transfer of 6.9 KV bus. This event resulted in a loss of power to two (2) reactor coolant pumps. Are these pumps located on the same loop? How was this modeled with CESEC and why is this single failure considered the most limiting?

(i) A steam line break inside containment results in a containment isolation actuation signal (CIAS). This, we understand, isolates the component cooling water from the RCP seals. Justify that loss of CCW would not result in damage to the RCP seals, which in turn could result in a primary system LOCA at all four pumps; otherwise, assume pump seal failure concurrent with the steam line break. Show that operator emergency procedures are sufficient to preclude operator misdiagnosis of this event and, consequently, incorrect actions.

(j) Provide a graph overlaying the intact and broken loop hot leg temperatures.

(k) The CESEC-SLB computer program (also known as CESEC-III) was utilized in evaluating the steam line break events. This code has not been reviewed by the NRC. The updating of CESEC-II to CESEC-III, as documented in Section 15D, indicates that considerable modifications have been made to CESEC-II. The documentation provided in Section 15D is not adequate for assessing this new code. The CESEC-III program appears to contain significant modifications and improvements from the CESEC-II program. We require full documentation of this program, comparative analyses with CESEC-II, integral experimental verification for evaluation of asymmetric transients, and verification with plant operational transient data. We also require detailed documentation of the following models:

(i) Steam generator heat transfer constant K_R as documented on page 15D-4, including data and equation of the experimentally determined constant.

(ii) New method for evaluating the steam generator heat transfer coefficient, as documented on page 15D-13.

(iii) Details of the pressure calculations (e.i., does CESEC-III evaluate pressure at each node? If not, how is the hydraulic influence of primary system voiding addressed?)

(iv) Cross flow model including verification with experimental and integral tests.

(v) Verification of the pump model, including natural circulation predictive capabilities.

(l) Page 15.1-80 states that a containment isolation results in loss of instrument air. Describe which instruments (and controls) are affected and the consequences of their loss.

(m) Why does the steam line break event, concurrent with loss of off-site power, result in an extended loss of pressurizer level when compared to the same break size concurrent with failure to load a 6.9KV bus? Extend both analyses to the point of the HPI termination criterion. Provide similar analyses for a double-ended guillotine break in the steam line.

440.81 The following concerns address Section 15.2.5:

(a) Describe how the SECES program accounts for the energy input by the reactor coolant pumps.

(b) CESEC-II was utilized in assessing the consequence of a feedwater line break. This program cannot properly assess asymmetry within the reactor vessel and the hot legs. Provide confirmatory analyses with a suitable code or otherwise justify that asymmetry has negligible influence on the pressurization of the primary system.

(c) Why was the auxiliary feedwater initiated 650 seconds into the postulated steam line break event, but for the feedwater line break event, the AFW was initiated 326 seconds into the transient? How are the consequences to these events changed for automatic initiation of AFW?

(d) Describe the single failure assumed for the feedwater line break events. Why is this failure considered the limiting one?

(e) Page 15.2-150 states: "Auxiliary feedwater was assumed to be activated by the plant operator within five minutes of the low steam generator level trip condition to prevent the pressurizer from filling solid." Compare the five-minute delay time for AFWS initiation to the time imposed by Action Item II.K.3.5, which requires automatic initiation of the AFWS. If the Action Item is in conflict with the five-minute delay assumed in the analysis, either justify the conservatism of this analysis or provide a new analysis of this event utilizing the appropriate AFW actuation time.

(f) The limiting feedwater line break was not a double-ended guillotine break (DEGB), but a 0.25 ft^2 small break.

The NRC will accept exceeding 110% design pressure for very low probability events, such as a double-ended guillotine break. However, for all break sizes less than a DEGB which result in the system pressure exceeding 110%, the applicant must demonstrate that the probability for these events is sufficiently low to satisfy the Level C Service categorization, as defined in Section 3 of the ASME Pressure Vessel Code.

We require the applicant to review all applicable data for justifying his position. We also require an assessment of the conservatism inherent in the analyzed events.

440.82 All Chapter 15 analyses assumed operator action for auxiliary feedwater initiation. NUREG-0737 requires the incorporation of an automatic initiation of the auxiliary feedwater system. Therefore, we require that the applicant reanalyze the depressurization transients accounting for auxiliary feedwater as it would be initiated without operator intervention. A detailed description of the auxiliary feedwater system, as modified for automatic initiation, should also be provided.