9

Attachment 8 to PLA-6076

Startup Testing

Susquehanna Steam Electric Station

Extended Power Uprate

Attachment 8 to EPU NRC Submittal
<u>Startup Testing</u>

Table of Contents

Table of Contents (Continued)

1.0 Introduction

The following information supplements the Susquehanna Steam Electric Station ("SSES") Power Uprate Safety Analysis Report ("PUSAR") and provides additional information about startup testing as is required by SRP 14.2.1 – Generic Guidelines for Extended Power Uprate Testing Programs.

2.0 Purpose

2.1 Background

This attachment provides detailed information on the testing PPL intends to perform following the EPU implementation outages. The first implementation outage will be on Unit 2 in 2007 followed by Unit 1 in 2008. The first implementation outage on each unit will upgrade plant equipment and load fuel sufficient to support operation at 3733 MWt. The next implementation outage will be on Unit 2 in 2009 followed by Unit 1 in 2010. These outages will upgrade plant equipment and load fuel sufficient to support operation at 3952 MWt. During the startup following each of these implementation outages, PPL will conduct a comprehensive startup test program to ensure the safe operation of the plant. The tests that PPL intends to perform are described herein.

The Nuclear Regulatory Commission ("NRC") decides whether Large Transient Testing is necessary during power ascension to Extended Power Uprate ("EPU") on a plant by plant basis. SSES plans to perform a Constant Pressure Power Uprate ("CPPU") to 3,952 MWt. The planned CPPU is approximately fourteen percent (14%) above current licensed thermal power (3,489 MWt) and twenty percent (20%) above original licensed thermal power (3,293 MWt). The purpose of this report is to describe the startup testing SSES intends to perform in support of EPU and to supplement the SSES CPPU application to assist the NRC in making a final determination relative to Large Transient Testing at SSES.

The NRC endorsed the Licensing Topical Report (NEDC 32424P-A called ELTR1) for Extended Power Uprates. The NRC also accepted the test program of the CPPU Licensing Topical report (NEDC 33004P-A called CLTR) for CPPUs, but reserved the right to consider on a plant by plant basis the CLTR recommendation against Large Transient Testing. The CLTR is the controlling document for the SSES planned CPPU. SSES will comply with the startup test requirements of the CLTR and will take exception to performing Large Transient Tests.

ELTR1 stated MSIV Closure Events would be tested for EPU if the power uprate was more than 10% above any previously recorded MSIV closure transient. Similarly, ELTR1 stated a generator load rejection test would be performed if the uprate was more than 15% above any previously recorded generator load rejection transient. ELTR1 applies to extended power uprates whether constant pressure or otherwise. The CLTR on the other hand, applies directly to constant pressure power uprates.

With regard to these specific ELTR1 requirements, SSES recorded a MSIV closure event in Unit 1 on July 1, 1999 and a generator load reject event in Unit 2 on June 6, 2005 and. Based on these two events, the ELTR1 criteria apply to SSES as follows:

Event	Date	Power Level	CPPU Power Level	% Increase	Required by ELTR1
MSIV Closure Event	7-1-1999	3441 MWt	3952 MWt	14.9%	Yes—greater than 10%
Generator Load Reject	6-6-2005	3489 MWt	3952 MWt	13.3%	No—less than 15%

The CLTR states: "The same performance criteria (for CPPU) will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program. Because neither steam pressure nor core flow has been changed and because recirculation flows only slightly increase for CPPU, testing of system performance affected by these parameters is not necessary with the exception of the test listed above." No performance criteria have been replaced by updated criteria since initial testing at SSES.

2.2 Objective

This supplement is submitted to support the request to the NRC that Large Transient Testing not be required before CPPU at SSES. The supplement addresses all guidelines of SRP 14.2.1, even though the only ELTR1 event that would require testing is the MSIV closure event and in spite of the fact that the CLTR applies to SSES and the CLTR states testing is not required where core flow and steam pressure remain essentially unchanged.

3.0 Summary of Conclusions

PPL has determined per SRP 14.2.1 which of the original startup tests described in the FSAR need to be performed for EPU. The startup tests PPL intends to perform for EPU are described in Table 3. This includes a commitment to perform a condensate pump trip on one unit to verify continued feedwater capability.

PPL has also determined the post EPU modification tests that impact plant safety that will be performed. The post EPU modification tests are described in Table 2. Table 2 includes tests on modifications that do not impact plant safety, but are included for completeness.

As further detailed below, Large Transient Testing at SSES is not required for CPPU because: (A) SSES has already tested large transient events and has documented the results; (B) potential gains from further Large Transient Testing are minimal and are outweighed by the potential harm testing can cause; and (C) advanced analytical methods and advanced training facilities accurately and adequately simulate large transient events without the need to impose actual events. In view of previous test results and plant responses to prior documented events, the CPPU startup testing program as proposed in this document is considered sufficient to validate the continued ability of the plant to safely operate within required parameters and analytical limits.

A. <u>SSES has tested large transient events and has documented results.</u>

   Large Transient Testing performed during plant startup testing determined integrated plant response after reaching full power. Startup tests were required to baseline plant responses and to individualize system performances. Startup test results indicate Structures Systems and Components ("SSCs") perform their intended functions. SSES satisfied all Acceptance Criteria necessary at startup testing. During startup testing SSES uncovered potential equipment defects for DBA mitigation by deliberately placing the plant in transient events. Further Large Transient Testing for CPPU is not required because events have been baselined by startup testing, actual events, post modification testing, and by analytical techniques.

   Testing to gain information that is minimal to plant operation and that SSES has already established is cumulative and disruptive, and subjects the plant to unnecessary increased risk. Large Transient Testing challenges a limited number of systems and components, all of which have a history of safe performance at SSES. SSES has accumulated twenty (20) years of experience dealing with plant transient response. Therefore, the need to perform additional testing to demonstrate plant response at CPPU is not justified.

B. Gains from Large Transient Testing are minimal, and outweighed by the potential harm Large Transient Testing can cause.

No new transients occur as a result of CPPU. Transient analyses at CPPU resemble analyses at current plant conditions. Changes in plant conditions for CPPU are not expected to result in a significant change to current plant conditions and response. Therefore, SSES has already performed sufficient testing and any gains from further testing are minimal and would be outweighed by the potential harm Large Transient testing can cause.

No new thermalhydraulic phenomena or system interactions have occurred following actual turbine trip and load reject events at SSES. Plants responded as expected in accordance with their design features. No unexpected conditions were experienced and no latent defects were uncovered during these events, beyond the specific failures that initiated the events.

The proposed EPU test program tests the aggregate impact of plant modifications. Plant modifications to support CPPU have minimal safety significance. Modifications are implemented as needed in advance of CPPU implementation.

Benefits derived from Large Transient Testing may be achieved by safer means. CPPU has minimal affect on plant modifications. Correct and timely operator responses to plant transients and abnormal events (as well as DBAs) are assured and documented by simulator training.

The risk associated with a planned transient is on the same order of magnitude as the risk of an unplanned transient event. From a PRA perspective, Large Transient Testing should not be performed unless clear benefits are achievable and cannot be obtained through other methods. Large Transient Testing without significant need and well defined goals is unwarranted.

C. Advanced Analytical Methods and training facilities accurately and adequately simulate large transient events and system performance.

Advances in analytical techniques, methods, models, and simulators have created a high level of confidence in determining plant responses and are cost effective alternatives to actual testing. Analyses and simulator training demonstrate that plant shutdown is safely achieved under CPPU conditions.

The benefits from Large Transient Testing are outweighed by the potential affects Large Transient Testing has on plant equipment. Large Transient Testing has a negative impact on the station and power grid, for which the station supplies a significant base load. Large Transient Testing provides information on a limited number of plant systems. The scram and subsequent rapid reduction in power is controlled by normal operator actions. Therefore, the need to perform Large Transient Testing at SSES to demonstrate safe operation of the plant is unwarranted.

D. SSES plant simulator models BOP transients.

The SSES plant simulator provides accurate BOP modeling of transients such that operators will be well trained and experienced in potential EPU transients or events. Prior to EPU implementation, the simulator will be updated to model the EPU transient analyses. SSES operators will be trained on various plant upset conditions from postulated accident conditions to anticipated transients. In this way, plant operators will be prepared for the nature, timeline, and extent of the plant response to simulated transients. Initiating actual plant transient events for purposes of operator training will not be necessary. Simulator training has the advantage of exposing all operating shifts to the transients whereas only the on duty shift has the hands on experience of in-plant transients.

4.0 Testing Evaluations

4.1 Comparison to SSES Startup Test Program [SRP 14.2.1; III.A]

Power ascension startup tests performed at ≥ 80% of OLTP

Table 1 provides comparisons of initial startup tests and startup tests for the 4.5% uprate to 3441 MWt to planned testing for CPPU startup. As seen in Table 1, the following tests were performed at 80% of OLTP or greater: ST-1, ST-2, ST-5, ST-8, ST-9, ST-11, ST-12, ST-16, ST-17, ST-18, ST-19, ST-20, ST-21, ST-24, ST-29, ST-32, ST-33, ST-35, ST-36, and ST-37. Planned testing for CPPU is indicated in Table 1, with additional details provided in Table 3. Justifications for exemption from certain transient testing are provided in paragraph 4.3 below. A listing of transient tests performed at 80% or greater during initial startup testing is provided in the following paragraph.

Power ascension transient tests performed at ≥ 80% of OLTP

Table 1 to this supplement provides a complete comparison of initial startup tests to the startup tests performed for the uprate to CLTP (3,489 MWt) and the tests planned for CPPU (3,952 MWt). As seen in Table 1, the following table shows those startup transient tests performed at 80% of OLTP or greater. This table is provided in accordance with SRP 14.2.1, paragraph III.A.1 and III.A.2. Initial startup tests, along with test power levels, are also provided in Table 1 to this Attachment.

Initial Transient Test	Test Number	Power Level		UFSAR Page No.	Attachment 2 to SRP 14.2.1
		U1	U2		
Pressure Regulator	ST-22	97.5%	99%	14.2-81	Yes
Feedwater Pump Trip	ST-23.5	97%	97%	14.2-33	Yes
Loss of Feedwater Heating	ST-23.4	85%	82%	14.2-33	Yes
Turbine Valve Surveillance	ST-24	100%	100%	14.2-241	No
Closure of All MSIVs	ST-25	100%	100%	14.2-241	Yes
Turbine Trip/Generator Load Rejection	ST-27	98%/100%	97%	14.2-244	Yes
Recirculation Flow Control	ST-29	98%	96%	14.2-247	No
Recirculation Pump Trip (One Pump)	ST-30	70%/98%	72%/98%	14.2-248	Yes

Tests at lower power invalidated by EPU

In accordance with SRP 14.2.1, paragraph III.A.2, the startup tests of Table 1 were reviewed for potential tests that would be invalidated by EPU. No such testing was identified for the SSES CPPU.

Attachments 1 and 2 of the SRP 14.2.1

In accordance with SRP 14.2.1, paragraph III.A.2, Attachments 1 and 2 of SRP 14.2.1 were reviewed for consistency with the SSES startup testing program. The following tests, shown in Attachment 2 of SRP 14.2.1, were not performed during SSES startup at power levels greater than 80%. They are included here for completeness and are also discussed in the justifications of paragraph 4.3

Initial Transient Test	Test Number	Power Level		Applicable to SSES	Reference
		U1	U2		
RCIC Functional Testing	ST-14	<75%	<75%	No	Startup Report
HPCI Functional Testing [1]	ST-15	<75%	<75%	No	Startup Report
Relief Valve Testing	ST-26	45%	41%	No	Startup Report
Recirculation Pump Trip (Two Pumps)	ST-30	75%	72%	No	Startup Report

[1] HPCI testing is not listed in Appendix 2 to SRP 14.2.1 but is included here due to its similarity to RCIC testing.

4.2 Post Modification Testing Requirements [SRP 14.2.1, III.B]

Table 2 provides a listing of EPU implementation modifications that are currently anticipated and that are being prepared for implementation between 2006 and 2010. The SSES Units plan to implement EPU over two fuel cycles, as shown below. In view of this two step process, implementation of the DCPs of Table 2 will occur throughout the period.

SSES Unit	Uprate Step	Increase	Date
Unit 2	1st	~ 7% to 3733 MWt	Spring 2007
Unit 1	1st	~ 7% to 3733 MWt	Spring 2008
Unit 2	2nd	Up to 1300 MWe[2]	Spring 2009
Unit 1	2nd	Up to 1300 MWe[2]	Spring 2010

Modification Aggregate Impact

As can be seen from inspection of the modifications list of Table 2, the aggregate impact of most of these modifications on plant operations is minimal. The majority of the modifications are minor changes. The modifications that are more significant (e.g. HP turbine replacement, SLCS boron enrichment, and UHS modifications) are largely unrelated to each other, and therefore the aggregate impact of the changes is relatively insignificant. With some of the changes that are more interrelated (e.g. piping changes in main steam, feedwater, and extraction steam), the extent of the changes themselves are minor (drain piping changes or pipe support modifications). An overall aggregate impact of these changes is not anticipated.

Condensate system and feedwater system upgrades do represent significant plant modifications, such as replacement of condensate pump impellers, upgrade of RFP turbines and steam path, installation of an additional condensate filter and condensate demineralizer, and changes to RFP low suction pressure trips. These modifications will have an aggregate impact on BOP systems. However, these changes will be adequately addressed during post modification testing and the aggregate impact will be addressed by feed water system power ascension testing. Feed water system testing is described in Table 3 (ST-23). Also, the impact of EPU flow rates and condensate pump head (impeller changes) on RFP low suction trip set-points will be tested during power ascension on the first unit in order to demonstrate that sufficient margins are assured to preclude loss of all feedwater on loss of a condensate pump. The current sequential trip of RFPs on low suction pressure will be retained post EPU. The sequential trip feature assures that loss of a condensate pump can not credibly result in a loss of all reactor feedwater at SSES.

Aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes will be demonstrated by a test program established for BWR EPU in accordance with startup test specifications as described in PUSAR Section 10.4. The startup test specifications are based upon analyses and GE BWR experience with uprated plants to establish a standard set of tests for initial power ascension for CPPU. These tests, which supplement the normal Technical Specification testing requirements, are summarized below:

- Testing will be performed in accordance with the Technical Specifications Surveillance Requirements on instrumentation that is recalibrated for CPPU conditions. Overlap between the IRM and APRM will be assured.
- Data will be taken at points from 90% up to 100% of the CLTP RTP, so that system performance parameters can be projected for CPPU power before the CLTP RTP is exceeded.

[2] Full power during initial startup (Test Condition 6) was defined as 95% to 100% of rated thermal power and 100% +0 and minus 5% of rated core flow. The plant is expected to be generator limited to 1300 MWe on startup after EPU implementation, which falls within the TC 6 definition.

- CPPU power increases will be made in predetermined increments of ≤5% power. Operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows, and vibration will be evaluated from each measurement point, prior to the next power increment. Radiation measurements will be made at selected power levels to ensure the protection of personnel.
- Control system tests will be performed for the reactor feedwater/reactor water level controls, and pressure controls, as applicable. These operational tests will be made at the appropriate plant conditions for that test at each of the power increments, to show acceptable adjustments and operational capability.
- Steam dryer/separator performance will be confirmed within limits by determination of steam moisture content as required during power ascension testing.
- Testing will be done to confirm the power level near the turbine first stage scram bypass set point.

The same performance criteria will be used as in the original power ascension tests, except where they have been replaced by updated criteria since the initial test program. Because steam pressure and core flow have not changed and recirculation flow may only slightly increase for CPPU, testing of system performance affected by these parameters is not necessary with the exception of the tests listed above.

The CPPU testing program at SSES, which is based on the SSES specific initial CPPU power ascension and Technical Specifications, has been reviewed and is confirmed to be consistent with the generic description provided in the CLTR.

Multiple Structure Systems and Components ("SSC")

Functions important to safety and that rely on integrated operation of multiple SSCs following plant events (such as plant load swings and loss of feedwater heating) are adequately addressed for SSES, as further described in Section 4.3 below.

4.3 Justifications for Elimination of Power Ascension Tests [SRP 14.2.1, III.C]

Guidelines of SRP 14.2.1, Paragraph III.C.2

Paragraph III.C.2 of SRP 14.2.1 provides specific guidance to be considered in order to justify elimination of large transient testing. The following table provides a cross reference between the guidance of paragraph III.C.2 and this Attachment to the SSES CPPU application. The table is provided to assist Staff reviewers in locating or identifying the appropriate information.

Paragraph III.C.2	Guidance/Criteria	Discussion/Location in This Document
(a)	Previous operating experience	Contained in paragraph 4.3 where applicable to specific tests and in paragraph 7.0 for post EPU industry experience.
(b)	New thermalhydraulic phenomena or system interactions	No new thermalhydraulic phenomena or new system interactions were identified as a result of SSES CPPU. No further discussion is provided.
(c)	Conformance with limitations of analytical methods	SSES has no unique limitations associated with conformance to analytical methods. No further discussion of this subject is provided.

(d)	Plant staff familiarization with facility operation and EOPs	Provided in paragraph 5.0
(e)	Margin reduction in safety analysis for AOOs	Provided in paragraph 4.3 for specific tests, where applicable. Discussed in the section on EPU analyses results.
(f)	Guidance in Vendor topical reports	Discussed in paragraph 2.1 above
(g)	Risk implications	Provided in paragraph 6.0

Based upon paragraph 4.1 above, the following large transient tests are discussed below along with justifications for why further Large Transient Testing is not required before CPPU. These tests include Pump Trip, Loss of Feedwater Heating, Closure of MSIV, Turbine Trip/Generator Load Reject, Recirculation Pump Trip, Relief Valves, RCIC Functional Testing, and HPCI Functional Testing.

Feedwater /Condensate Pump Trip

The Feedwater Pump Trip startup test checks the recirculation system's ability to prevent a low water level scram from occurring following the trip of one Feedwater Pump operating at EPU. The startup test Feedwater Pump Trip at SSES established this occurrence and therefore further testing for Feedwater Pump Trip is not necessary.

Startup Test Objectives

The objective for the startup Feedwater Pump Trip test was to test the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump. The Acceptance Criteria and testing methods for Feedwater Pump Trip are described in FSAR 14.2.

Startup Test Results

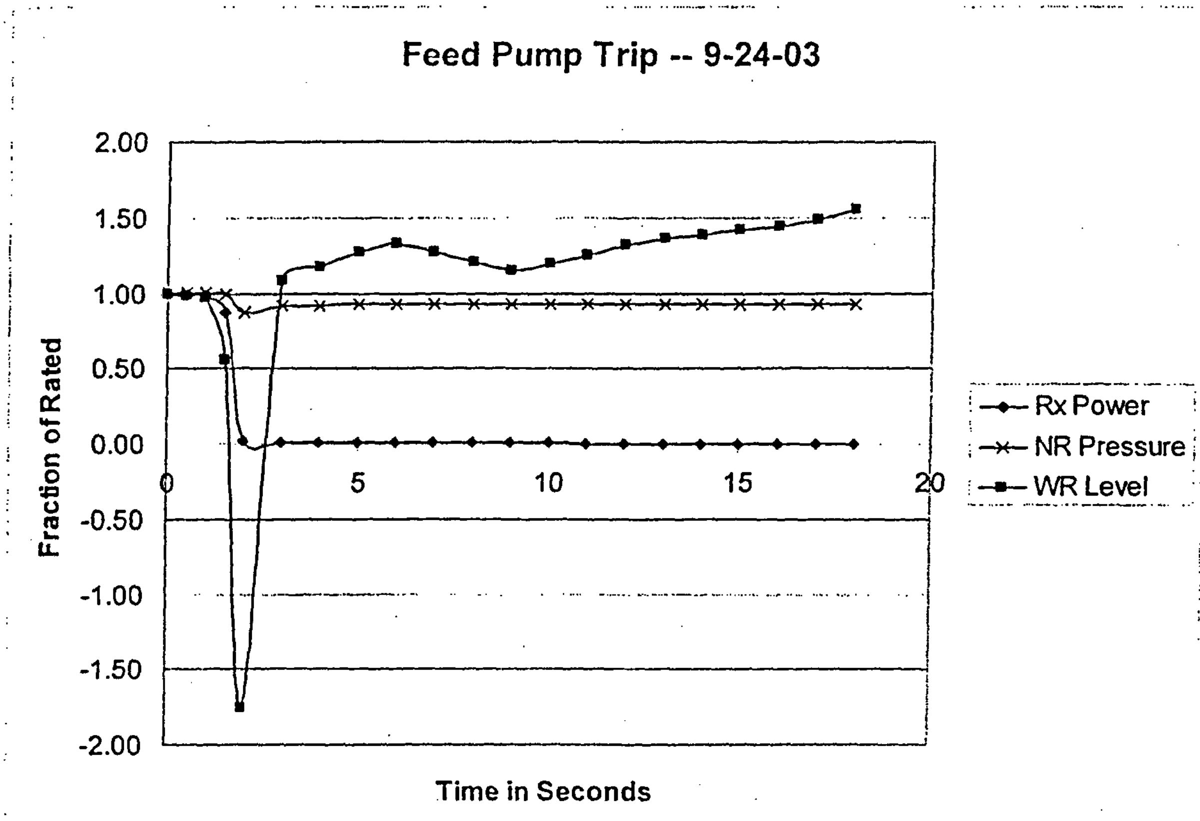
All Acceptance Criteria for startup Feedwater Pump Trip testing was satisfied for Unit 1 and Unit 2.
Demonstrate the Capability of the Automatic Core Flow Runback Feature to Prevent Low Water Level Scram Following the Trip of One Feedwater Pump.

- Unit 1: Startup testing was conducted at Test Condition 6 and with reactor power level at 97%. The "B" Feedwater Pump was tripped. The recirculation pump speeds ran back to the number 2 Limiter (approximately 46% speed) and this prevented a reactor scram from low water level.

- Unit 2: Startup testing was conducted at Test Condition 6 and with reactor power at 97%. The "B" Feedwater Pump was tripped to determine the resulting margin to scram. A scram did not occur and the resulting margin to the low reactor water level scram, extrapolated to 100% reactor power, was sixteen inches. Sixteen inches meets the Acceptance Criteria of greater than or equal to three inches.

Operational Experience Since Startup

On September 24, 2003, a feed pump trip occurred in Unit 1. As demonstrated in the following graph, a reactor trip occurred when reactor vessel level dropped below the trip set point. While the trip was subsequently attributed to inappropriate recirculation control system gain settings which inhibited the runback capability of the recirculation system (and was later corrected), the event does show that a feedwater pump trip could result in a reactor scram at current licensed thermal power (CLTP). EPU transient analyses (described below) shows that a reactor SCRAM will occur at EPU power levels on a feedwater pump trip. While this is not a desirable result from a power generation standpoint, there are no safety implications associated with this condition.



EPU Transient Analysis Results/CPPU Margins

Several single feed water pump trip (SFWPT) events were evaluated, originating from 3952 MWt and 3733 MWt with core flows ranging from 108% to 85%. The trips were simulated using GE transient code analyses. The analyses were performed at BOC conditions as GE states that this is the worst condition. Specifically, for the limiting case, water level results reached the Level 3 SCRAM setpoint

In view of the Level 3 SCRAM, SSES is changing its licensing basis for SFWPT to indicate that a reactor SCRAM on low water level may occur during this event, in which case there would be no need to test this result because a reactor SCRAM places the plant in a safe condition.

SRP 15.2.7 discusses loss of normal feedwater flow. The SRP states that main steam system pressure should remain below 110% of the design value. As shown in the plot of the 9-24-03 event (above), an increase in reactor or main steam pressure during this event is not an issue. Also, system design pressure margins are not affected by CPPU since, even though main steam and feedwater flows increase at CPPU, the numbers and setpoints of the SRVs are unchanged and therefore pressure peaks will be limited exactly in accordance with current design conditions.

EPU Power Ascension Testing

Planned EPU power ascension testing of the feedwater control system is described in Table 3 (Test #23). For example, feedwater control system responses to reactor water level set point changes (for level set point change tests) are evaluated in various control modes (i.e. three element, single element). However, power ascension testing of a feedwater pump trip is not planned since a reactor scram on low level is anticipated and therefore such a test is not meaningful.

At the same time, while not part of the initial feedwater trip startup test (ST-23) nor part of Appendix 1 or 2 of SRP 14.2.1 (which incorporates by reference RG 1.68, Section 5), SSES intends to conduct condensate pump testing to confirm that a condensate pump trip does not result in a loss of all feedwater, as further detailed below.

1. SSES will perform hydraulic analyses to demonstrate that a single condensate pump trip will not result in a loss of all feedwater. [Note: The SSES design incorporates time delays into the feedwater pump low pressure suction trips such that trip of the first feedwater pump on low suction pressure should restore the suction pressure to the other two pumps. These analyses will consider both steps of power uprate, namely the 7% increase to 3733 MWt and the remaining increase to 3952 MWt.

2. SSES will conduct a condensate pump trip at full power during the 7% increase to 3733 MWt on the first unit to attain this power level to confirm the capability of feedwater to supply water to the RPV after the condensate pump trip.

3. Assuming both the 3733 MWt analysis and the 3952 MWt analysis demonstrate that loss of a condensate pump does not result in a loss of all feedwater, and assuming that the results of the full power test at the 3733 MWt step are comparable to the 3733 MWt analysis, testing of this matter will be considered to be satisfactorily resolved and repeat testing of 3952 MWt will not be conducted.

4. If the results of the 3733 MWt test are not sufficient to reasonably confirm the analysis model used for the 3733 MWt step, the condensate pump trip test will be repeated at 3952 MWt on the first unit to attain this power level.

Conclusion

Power ascension testing does not anticipate actual testing of a feedwater pump trip, because a reactor scram on low level is anticipated and therefore such a test is not meaningful. However, condensate pump trip testing, as detailed above, will be conducted as part of the SSES power ascension testing. This testing will confirm that a condensate pump trip will not result in a loss of all feedwater flow.

Loss of Feedwater Heating

The loss of feedwater heating portion of the Feedwater System startup tests verifies that the maximum decrease due to a single failure case is less than or equal to 100 °F. The resultant MCPR must be greater than the fuel safety limit. The startup test for Loss of Feedwater Heating at SSES established this occurrence and therefore further testing is not necessary.

Startup Test Objectives

The objective for startup test Loss of Feedwater Heating is to determine stable reactor response to subcooling changes (i.e. Loss of Feedwater Heating) and to show that the actual change in final feedwater temperature is less than that assumed in the analysis. The Acceptance Criteria and testing methods for Loss of Feedwater Heating are described in FSAR 14.2.

Startup Test Results

All Acceptance Criteria for startup Loss of Feedwater Heating testing was satisfied for Unit 1 and Unit 2.

Determine Stable Reactor Response to Subcooling Changes (i.e. Loss of Feedwater Heating).

- Unit 1: Startup testing at 85% power, a simulated turbine trip signal to the extraction steam valves were initiated which would result in the most severe restriction of extraction steam to one feedwater heater string. Recordings of the transient were analyzed and compared to the predicted response and Acceptance Criteria. The decrease in final feedwater temperature was 44°F and all other acceptance criteria were met.

- Unit 2: Startup testing at 82% power, a simulated turbine trip signal to the extraction steam valves was initiated which resulted in the most severe restriction of extraction steam to one feedwater heater string. Recordings of the transient were analyzed and compared to the predicted response and Acceptance Criteria. The decrease in final feedwater temperature was 34 °F and all other acceptance criteria were met.

Based on plant historical data and EPU analytical results, the decrease in final feedwater temperature and the response of the feedwater system and the reactor to a loss of feedwater heating are well within the analysis, therefore a loss of feedwater heating startup test is not necessary.

EPU Transient Analysis Results/CPPU Margins

A loss of feedwater heating (LFWH) transient can occur in one of two ways:

- A steam extraction line to a feedwater heater is closed.
- Inadvertent opening of the turbine bypass valves.

The first case produces a gradual drop in the temperature of the feedwater. In the second case, the reduced steam flow through the turbine reduces extraction pressures and temperatures, resulting in a temperature reduction in the isolated heater string and overall feedwater heating is reduced. Both cases cause a decrease in the temperature of the feedwater entering the reactor vessel. This results in an increase in core inlet subcooling, which collapses voids and increases core average power and shifts the axial power distribution toward the bottom of the core. Because of this axial shift, voids begin to build up at the bottom again, acting as negative feedback to the void collapse process. This feedback moderates the core power increase.

A LFWH analysis was performed for the EPU equilibrium cycle core design using approved methodologies. An evaluation of the linear heat generation rate (LHGR) during a loss of feedwater heating transient for the EPU equilibrium cycle determined that the protection against power transients are not violated. The LHGR did not exceed 135% of the steady state value in any LFWH calculation.

SRP 15.1.1 provides acceptance criteria for loss of feedwater heating events. Loss of feedwater heating events at SSES, either under CLTP or CPPU conditions, do not challenge the criteria of SRP 15.1.1.

EPU Power Ascension Testing

Planned EPU power ascension testing of the feedwater control system is described in Table 3 (Test #23). For example, feedwater control system responses to reactor water level set point changes (for level set point change tests) are evaluated in various control modes (i.e. three element, single element). Level set point changes are tested at each test condition

EPU Power ascension testing does not anticipate tripping feedwater heaters, because this type of event is relatively common and typically results in mild transients that are well within the capability of the plant systems to handle.

Conclusion
Testing the loss of feedwater heating is not required because this type of event is relatively common and typically results in mild transients that are well within the capability of the plant systems to handle.

MSIV Closure Event

The MSIV Closure Event startup test functionally checks the Main Steam Isolation Valves for proper operation at selected power levels, determines reactor transient behavior during and following simultaneous full closure of all MSIVs, determines isolation valve closure time and determines the maximum power at which a single valve closure can be made without a scram. The startup test for MSIV Closure Event at SSES established this occurrence and therefore further testing is not necessary.

Startup Test Objectives
The objectives of the MSIV Closure Event startup tests are as follows: (1) functionally check MSIVs for proper operation at selected power levels; (2) determine reactor behavior during and following full and simultaneous closure of all MSIVs; (3) determine isolation valve closure time; and (4) determine the maximum power at which a single valve closure can be made without a scram. The Acceptance Criteria and testing methods for MSIV Closure Event are described in FSAR 14.2.

Startup Test Results
All Acceptance Criteria for MSIV Closure Event startup testing was satisfied for Unit 1 and Unit 2. Proper MSIV operation was demonstrated and proper closure times, during testing, at selected power levels for Unit 1 and Unit 2. The highest power level at which a single MSIV could be tested and still yield acceptable margins to scram and isolation was extrapolated and demonstrated to be 88.5% for Unit 1 and 88% for Unit 2. A full MSIV isolation was initiated from 100% power and the parameters of heat flux and reactor pressure were recorded and compared to predicted values for Unit 1 and Unit 2. Finally, valve closure time was adjusted to within acceptable limits for Unit 1 and proper operation was demonstrated and closure times were within limits for Unit 2.

Functionally check MSIVs for Proper Operation at Selected Power Levels

- Unit 1: During startup testing MSIVs were closed and tested individually during initial heatup at rated pressure, and during TC-1 at approximately 19% power. Proper operation was demonstrated and closure times were within limits. Neutron flux, reactor pressure, heat flux, and steam flow margins to scram or isolation were calculated and results were within limits.

- Unit 2: Each MSIV was individually closed and tested during initial heatup at rated pressure, TC-5 at approximately 64% power, and TC-6 at approximately 89% power. Neutron flux, reactor pressure, heat flux, and steam flow margins to scram or isolation were calculated and results were within limits.

Determine Reactor Behavior during and following Full and Simultaneous Closure of all MSIVs

- Unit 1: A full MSIV isolation was initiated from 100% power and the parameters of heat flux and reactor pressure were recorded and compared to predicted values. The actual pressure rise experienced during this test was such that no safety/relief valves lifted. RCIC and HPCI auto started and restored water level to normal. The maximum water level experienced was +65". The results are shown in the table below and all Acceptance Criteria were met during the test.

- Unit 2: A full MSIV isolation was initiated from 100% power and the parameters of heat flux and reactor pressure were recorded and compared to predicted values. The actual pressure rise experienced during this test was such that no safety/relief valves lifted. RCIC and HPCI auto started and restored water level to normal. The maximum water level experienced was +76". The results are shown in the table below and all Acceptance Criteria were met during the test.

Test	Predicted Heat Flux Increase	Actual Heat Flux Increase	Predicted Pressure Increase	Actual Pressure Increase	Average Closure Time	Maximum Water Level
Unit 1 Test 25.3 100% RP	1%	0%	116 psi	50 psi	3.2 sec	64.6 in.
Unit 2 Test 25.3 100% RP	<1%	0%	109.3 psi	50 psi	4.0 sec	76.2 in

Determine Isolation Valve Closure Time

- Unit 1: During startup testing MSIVs were closed and tested individually during initial heatup at rated pressure, and during TC-1 at approximately 19% power. Proper operation was demonstrated and closure times were within limits.

- Unit 2: Each MSIV was individually closed and tested during initial heatup at rated pressure, TC-5 at approximately 64% power, and TC-6 at approximately 89% power. Proper operation was demonstrated and closure times were within limits.

Determine the Maximum Power at which a Single Valve Closure can be made without a Scram

- Unit 1: The highest power level at which a single MSIV could be tested and still yield acceptable margins to scram and isolation was extrapolated and demonstrated to be 88.5%.

- Unit 2: The highest power level at which a single MSIV could be tested and still yield acceptable margins to scram and isolation was extrapolated and demonstrated to be 88%.

Operational Experience Since Startup

On July 1, 1999, a full MSIV closure event occurred in Unit 1. The event occurred when the inadvertent closure of one MSIV resulted in an indication of high steam flow in the remaining 3 steam lines. The first MSIV closed at time zero, with the remaining 3 closing at time 8 seconds. Reactor pressure remained fairly stable throughout the event, with reactor vessel level varying from slightly below instrument zero to approximately +60 inches. Data recorded during the event demonstrated that the plant responded as expected and that resulting parameters were well within guidelines and requirements.

The July 1999 event is not exactly the same as the startup tests (test #25.3), since there was an 8 second difference between closure of the first MSIV and closure of the other three. Nevertheless, a comparison of the July 1999 data with the startup testing data shows that the results are comparable.

	Unit 1 Startup Test	Unit 2 Startup Test	July 1999 Event
Actual Pressure Increase	50 psi	50 psi	20 psi
Maximum Level	64.6 inches	76.2 inches	59.6 inches

EPU Transient Analysis Results/CPPU Margins

The analysis of the closure of all MSIVs ("MSIVALL") was performed at EPU rated power and core flow conditions covering the full range of core flows at rated power. Comparing the limiting Delta CPRs for the MSIVALL transient with the results from other transients shows that the MSIVALL transient is not limiting with respect to Delta CPR at EPU rated power.

The following table lists the limiting Delta CPRs for the MSIVALL transient for the conditions analyzed.

Limiting Delta CPR Results for Closure of All MSIVs Event

Exposure (MWd/MTU)	ATRIUM-10 Delta CPR
	MELLLA
BOC to EOC	0.11

MSIV closure margins are discussed in SRP 15.2.4. Similar to the generator load reject event (GLR), the SRP states that reactor steam pressures should remain below 110% of the design value. As in the case of the GLR event, this is not an issue at SSES since the safety relief valves (SRVs) will easily maintain pressure below the design value. This was vividly demonstrated at SSES during a GLR event on June 6, 2005. This event is discussed (including a plot of RV pressure) in the GLR discussion below. As shown below, the RV pressure transient was limited to approximately 1100 psia by operation of two SRVs. Two SRVs operated during the 06-06-05 event. Even if a 3rd SRV were to operate at CPPU, there would be no change in pressure and no change in design margin.

EPU Power Ascension Testing / CPPU Modifications

EPU plant response during power ascension is tested and documented as described in the CTLR/ELTR. MSIV full closure testing at 100% core power during EPU power ascension testing is not required at SSES because the plant response at CPPU conditions is expected to be similar to the documented response during initial startup testing. The transient analysis performed for the SSES CPPU demonstrates that all safety criteria are met and that CPPU does not cause any previous non-limiting events to become limiting. However, deliberately closing all MSIVs from 100% power will result in an undesirable transient cycle on the primary system that can reduce equipment service life.[3] The transient loading provides no additional plant response information beyond that documented during startup testing and provides no benefit to safety equipment

Conclusion

Based on plant historical data and EPU analytical results, actual test results were well within expected limits. Actual pressure increase, in both Unit 1 and Unit 2 startup tests, were less than 50% of the expected values and further plant testing of MSIV Closure Event is not necessary.

[3] As demonstrated during startup and confirmed by analysis, all equipment responses to the transient are within component and system design capabilities. However, placing accident mitigation equipment into service, under maximum loading conditions, uses available service life. Equipment service life should be retained for actual events rather than for demonstration purposes.

Turbine Trip/Generator Load Rejection

The startup testing for Turbine Trip/Generator Load Rejection demonstrates the response of the reactor and its control systems to protective trips in the turbine and generator. The startup test for Turbine Trip/ Generator Load Rejection at SSES adequately demonstrated this response and further testing is not considered necessary.

Startup Test Objectives

The objectives of the Generator Load Rejection startup tests are as follow: (1) demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator; (2) demonstrate the capacity of the turbine bypass valves. The Acceptance Criteria and testing methods for Turbine Trip/Generator Load Rejection are described in FSAR 14.2.

Startup Test Results

All Acceptance Criteria for Turbine Trip/Generator Load Rejection startup testing were satisfied for Unit 1 and Unit 2 as further detailed below.

Demonstrate the Response of the Reactor and its Control Systems to Protective Trips in the Turbine and Generator

- Unit 1: This subtest was performed twice because the first test was invalidated when the transfer of the plant electrical loads did not occur. Test results follow.

  A generator load rejection was initiated by opening the Main Generator Breaker 230 KV OCB 1R101. This action initiates a fast closure of the Main Turbine Control Valves to limit the turbine overspeed. The load rejection was performed at 100% power. Fast transfer of the auxiliary bus from the unit auxiliary transformer to the startup transformer occurred. The plant responded as expected.

- Unit 2: All Acceptance Criteria were verified satisfactorily with exception of the two pump drive flow coastdown constants. The reactor operated at 97% power and the generator output breakers were opened causing a fast closure of the main turbine control valves and a subsequent reactor scram.

Demonstrate the Capacity of the Turbine Bypass Valves.

The objectives of the test were met and all Acceptance Criteria were satisfied for Unit 1 and Unit 2 except with the two pump drive flow coastdown time constant requirement, which was later evaluated and resolved.

- Unit 1: With the reactor operating at 25% of rated power level, so that the reactor scram signals on Turbine Control Valve Fast Closure and Turbine Stop Valve Trip were bypassed, the Main Generator Breaker was opened. This resulted in a Turbine Trip and Control Valve Fast Closure without causing a reactor scram. The bypass valves opened to control reactor pressure and the feedwater system maintained water level constant although a slight oscillatory response in water level was noted. The overall response was uneventful as anticipated.

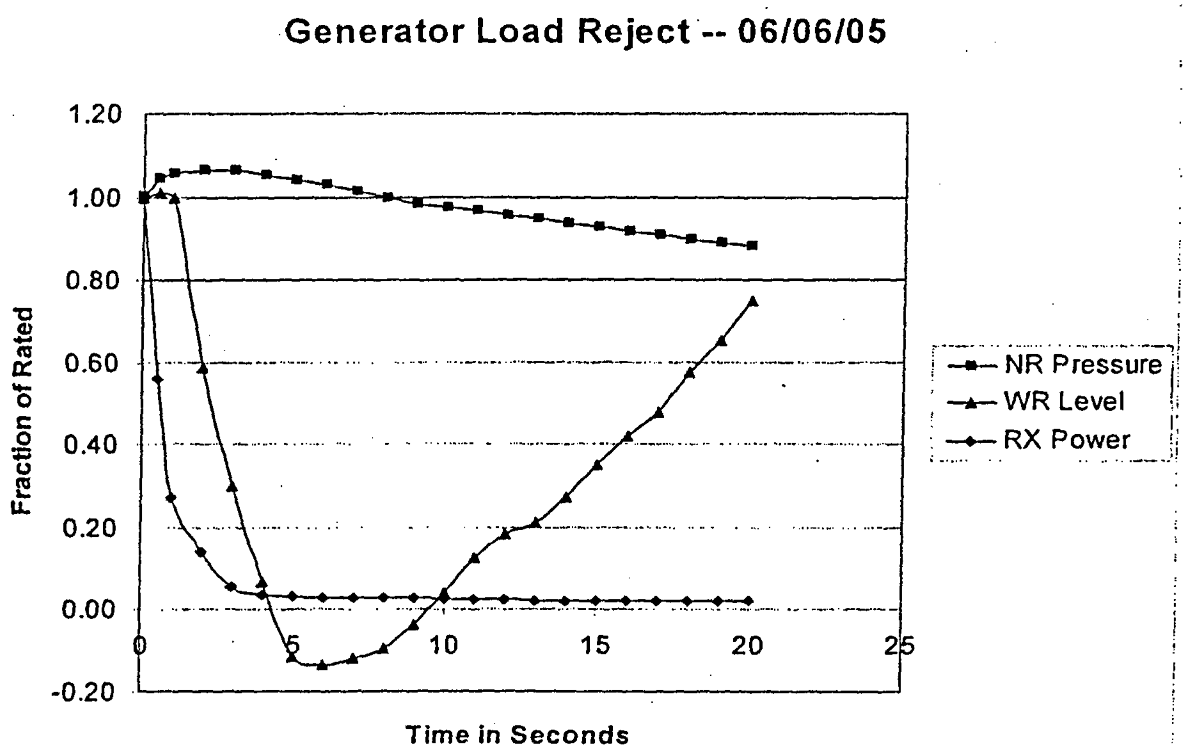
  A failure of the Level 1 Criteria which states that the bypass valves should be opened to a point corresponding to greater than or equal to 80% of full open within 0.3 seconds from the beginning of control or stop valve closure motion was encountered during this test. This failure resulted because power level at which the test was performed only required the bypass valves to open 73% to maintain pressure after the turbine trip. This response occurred in 0.2 seconds, which was determined to be acceptable.

Overall results confirm that conservative assumptions were made in the analysis of these events in Section 15 of the FSAR. The objectives of the test were met and All Acceptance Criteria was satisfied.

- Unit 2: Within the reactor operating at 20% of rated power level, so that the reactor scram signals on Turbine Control Valve Fast Closure and Turbine Stop Valve Trip were bypassed, the Main Generator Breaker was opened. This resulted in a Turbine Trip and Control Valve Fast Closure without causing a reactor scram. The bypass valves opened to control reactor pressure and the feedwater system maintained water level constant although a slight oscillatory response in water level was noted. The overall response was uneventful as anticipated. The delay time from the start of control or stop valve closure to the start of bypass valve opening was 0.05 seconds, which was less than the maximum allowed of 0.1 seconds.

Operational Experience Since Startup

A turbine trip/full load rejection event occurred in SSES Unit 2 on June 6, 2005. An electrical transient caused a trip of both recirculation pumps. As shown in the graph below, reactor vessel pressure remained fairly stable (after an initial peak to approximately 1100 psia) and level varied as expected. The feedwater system returned reactor water level to normal. Two SRVs opened and then closed. The bypass valves operated successfully and contributed to maintenance of steady vessel pressures. A recirculation pump was restarted to reestablish core flow. There were no challenges to the containment during this event.



EPU Transient Analysis Results/CPPU Margins

The Generator Load Rejection with bypass (LRWB) and the Turbine Trip with bypass (TTWB) events were conservatively combined as one event ("LRWB/TTWB"). The LRWB/TTWB event is identical to the Generator Load Rejection and Turbine Trip without bypass except the turbine bypass valves (TBV) are allowed to operate to help mitigating the pressurization event.

The LRWB/TTWB analyses were performed at EPU rated power and core flow conditions covering the full range of core flows at rated power. The following table lists the limiting change in Critical Power Ratios ("CPR") for the LRWB/TTWB transient for the conditions analyzed.

Limiting Delta CPR Results for Load Rejection/Turbine Trip With Bypass

Exposure	ATRIUM-10 Delta CPR
(MWd/MTU)	MELLLA
BOC to EOC	0.22

GLR margins requirements are given in SRP 15.2.6 (Loss of Non-Emergency AC Power). The SRP states the steam system should be maintained below 110% of the design value. As shown in the generator load reject event of 06-06-05 (above), RV pressure and steam pressure peak in the 1100 psia range due to operation of the SRVs. Two SRVs operated in the 06-06-05 event. Even if a 3rd SRV were to open at EPU conditions, the pressure profile would remain essentially the same. There would be no challenge to system design pressure. In addition, there would be no changes in pressure margins between CLTP and CPPU conditions.

EPU Power Ascension Testing

Turbine trip/generator load rejection testing at 100% core power during EPU power ascension testing is not required at SSES because plant responses at CPPU conditions are expected to be similar to the documented response seen during initial startup testing and the recent Unit 2 load reject on June of 2005. The transient analysis performed for the SSES CPPU demonstrates that all safety criteria are met and that CPPU does not cause any previous non-limiting events to become limiting. However, deliberately causing a load reject and subsequent scram from 100% power results in an unnecessary transient cycle on the primary system that can cause undesirable effects on equipment and grid stability. The transient loading provides no benefit to safety equipment. Therefore, additional load reject / turbine trip testing causing a scram from high power levels is not expected to result in plant response that has not been previously observed nor provide new insights into SSC performances.

Conclusion

In view of the above, transient mitigation capability is demonstrated by post modification testing and by Technical Specification required testing. In addition, the limiting transient analyses are included as part of the reload licensing analysis. From a safety significance standpoint, turbine trip/load reject testing cannot be justified in that the transient cycle on the primary plant is undesirable and the potential benefits from such a cycle are not safety significant. The potential for hidden defects or latent problems that might be uncovered (such as potential hanger failures or potential snubber failures) are not justified on the basis of safety significance, compared to the potential negative aspects of the transient. The response of the reactor and its control systems following trips of the turbine and generator has been demonstrated by numerous plant events and shown by EPU analysis to be acceptable. Therefore the objective of this test is satisfied without requiring actual plant transient testing.

Finally, full load reject testing is not required under the guidelines of ELTR1 as shown below:

Event	Date	Power Level	CPPU Power Level	% Increase	Required by ELTR1
Generator Load Reject	6-6-2005	3489 MWt	3952 MWt	13.3%	No—less than 15%

Recirculation Pump Trip

Information gathered during startup Recirculation Pump trip testing is used to (1) obtain recirculation system performance data during pump trip, flow coastdown and pump restart; (2) verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip and associated scram; (3) record and verify acceptable performance of the recirculation two pump circuit trip system; (4) verify the adequacy of the recirculation runback to mitigate a scram, and (5) verify that no recirculation system cavitation will occur in the operable region of the power-flow map. The Recirculation Pump Trip startup test satisfied acceptance criteria and therefore further testing is not necessary.

Startup Test Objectives

The Recirculation Pump Trip startup test objectives are: (1) obtain recirculation system performance data during pump trip, flow coastdown, and pump restart; (2) verify that the Feedwater Control System can satisfactorily control water level without a resulting turbine trip and associated scram; (3) record and verify acceptable performance of the recirculation two pump circuit trip system; (4) verify the adequacy of the recirculation runback to mitigate a scram: (5) verify that no recirculation system cavitation will occur in the operable region of the power-flow map. The Acceptance Criteria and testing methods for Recirculation Pump Trip are described in FSAR 14.2.

Startup Test Results

The overall Acceptance Criteria and objectives for the Recirculation Pump Trip test were satisfied for Unit 1 and Unit 2.

Obtain Recirculation System Performance Data during Pump Trip, Flow Coastdown, and Pump Restart and Verify that the Feedwater Control System can Satisfactorily Control Water Level without a Resulting Turbine Trip and Associated Scram and R ecord and Verify Acceptable Performance of the Recirculation Two Pump Circuit Trip System

- Unit 1: RPT breakers were simultaneously tripped using a temporary test switch while the power was at 75% and core flow was at 100%. Flow coast down times were acceptable.

  MG Set breakers were tripped from the control room at 70% power and 100% core flow and an unexpected MG Set breaker trip occurred due to a circuit board failure at 98% power and 98% core flow. For each trip, recordings of reactor parameters were made during the ensuing transient and these recordings were analyzed to verify non-divergence of oscillatory responses, adequate margins to RPS set points and capability of the feedwater system to prevent a high water level trip. The restart capability of the recirculation pump at high power level was also demonstrated. The margins to scram that were measured during the pump trip and pump restart were found to be acceptable.

- Unit 2: RPT breakers were simultaneously tripped using a temporary test switch while the power was at 72% and core flow was at 99%. Flow coast down times were acceptable.

  Breakers were tripped from the control room at 72% power and 96% core flow and again at 98% power and 99% core flow. During each trip recordings of reactor parameters were made during the ensuing transient and these recordings were analyzed to verify non-divergence of oscillatory responses, adequate margins to RPS set points and capability of the feedwater system to prevent a high water level trip. The restart capability of the recirculation pump at high power level was also demonstrated. The margins to scram that were measured during the pump trip and pump restart met acceptance criteria.

Verify the Adequacy of the Recirculation Runback to Mitigate a Scram

- Unit 1: Runback occurred producing a smooth transient for all parameters measured. A circulating water pump trip was simulated while running at 75% power and 100% core flow causing a runback to the number two Limiter setting of 45%..

- Unit 2: Runback occurred producing a smooth transient for all parameters measured. A feedwater pump was tripped and reactor water level allowed to drop below level 4 causing a runback of both recirculation pumps to the number two Limiter setting of 45% of rated speed. The feedwater pump was tripped while running at 71% power and 98% core flow.

Verify that no Recirculation System Cavitation Occurs in the Operable Region of the Power-Flow Map.

- Unit 1: This test demonstrates that the Feedwater Flow interlocks with the Recirculation Pump Number 1 Limiter are set such that cavitation will not occur in the Recirculation Pumps or Jet Pumps. The absence of pump cavitation is verified by observation of normally installed instrumentation to monitor the differential pressure across each recirculation pump, loop flow elbow tap and double tap jet pumps.

With reactor power at 57% and core flow at 100% of rated, the No. 1 Limiter was bypassed so the actual runback would not take place and control rods were inserted until the No. 1 Limiter actuated. This occurred at 20% of Total Feedwater Flow for each limiter. Cavitation was not observed.

- Unit 2: This test demonstrates that the Feedwater Flow interlocks with the Recirculation Pump No. 1 Limiter are set such that cavitation will not occur in the Recirculation Pumps or Jet Pumps. The absence of pump cavitation is verified by observation of normally installed instrumentation to monitor the differential pressure across each recirculation pump, loop flow elbow tap and double pumps.

  With reactor power at 51% and core flow at 95% of rated, the No. 1 Limiter was bypassed so the actual runback would not take place and control rods were inserted until the No. 1 Limiter actuated. This occurred at 20% of Total Feedwater Flow for each limiter. Cavitation was not observed. Acceptance Criteria 7 was verified in this subtest.

EPU Transient Analysis Results

Recirculation pump trip events were not analyzed since they have been dispositioned as non-limiting events. In addition, in a CPPU, core flow remains essentially unchanged. Therefore recirculation pump testing is not necessary.

EPU Power Ascension Testing/CPPU Margins

Core flow does not appreciably change in a CPPU. The results from startup testing and also from the events that have occurred during plant operations indicate recirculation pump trip testing is not necessary.

Because The feedwater flow value used to initiate the recirculation runback to the #1 limiter is unchanged for EPU, protection against cavitation is assured.,

SRP 15.3.1 provides criteria for loss of forced RCS flow events. None of these criteria are challenged at SSES either under CLTP conditions or at CPPU.

Conclusion

Based on plant historical data and EPU analytical results, (1) recirculation system performance data was collected, (2) the feedwater control system satisfactorily controls water level without a resulting turbine trip and scram, (3) the recirculation two pump circuit trip system performed acceptably, (4) the recirculation runback mitigated scrams, and (5) no recirculation system cavitation occurred in the operable region of the power-flow map and therefore further plant testing of Recirculation Pump Trip is not necessary.

Relief Valve Testing

This startup test Relief Valve Testing verifies that the relief valves function properly, reseat properly after operation, and contain no major blockages in the relief valve discharge piping. Startup testing showed that all relief valves functioned properly and reseated properly after operations. Testing demonstrated plant pressure control system stability during relief valve operation and showed that no blockages existed in relief valve discharge piping. Therefore further testing is not necessary.

Startup Test Objectives

The objectives for Relief Valve startup testing are: (1) verify that the relief valves function properly and can be manually opened and closed; (2) verify that the relief valves reseat properly after operation; (3) verify that there are no major blockages in the relief valve discharge piping; and (4) verify the proper operation of the relief valve actuation logic system. The Acceptance Criteria and testing methods for Relief Valve are described in FSAR 14.2.

Startup Test Results

Acceptance Criteria for Relief Valve startup testing was satisfied overall for Unit 1 and Unit 2.

Verify that the Relief Valves Function Properly, Can be Manually Opened and Closed, and Reseat Properly after Operation

- Unit 1: Relief Valve Rated Pressure Testing was implemented at 45% rated thermal power with a dome pressure of 944 psig. Each relief valve was manually cycled to verify proper operation at rated pressure. Pressure control system related variables were again observed for stability during relief valve actuation and the relief valve tail pipe temperatures were monitored after actuation to verify that each relief valve had properly reseated. All Acceptance Criteria were met during the test.

- Unit 2: Relief Valve Rated Pressure Testing was implemented at 41% rated thermal power with a dome pressure of 930 psig. Each relief valve was manually cycled to verify proper operation at rated pressure. Pressure control system related variables were again observed for stability during relief valve actuation and the relief valve tail pipe temperatures were monitored after actuation to verify that each relief valve had properly reseated. All Acceptance Criteria were met during the test.

Verify that there are No Major Blockages in the Relief Valve Discharge Piping

- Unit 1: Each relief valve was manually cycled to verify proper operation at rated pressure. The decrease in main generator electric output during each relief valve actuation was compared to the generator electric output average change, calculated after all relief valves had been actuated, to verify that no major blockages in valves or tailpipes existed. Relief Valve Rated Pressure Test was implemented at 45% rated reactor thermal power with reactor dome pressure at 944 psig during. All Acceptance Criteria were met during the test.

- Unit 2: Each relief valve was manually cycled to verify proper operation at rated pressure. The decrease in main generator electric output during each relief valve actuation was compared to the generator electric output average change, calculated after all relief valves had been actuated, to verify that no major blockages in valves or tailpipes existed. Relief Valve Rated Pressure Test was implemented at 41% rated reactor thermal power with reactor dome pressure at 930 psig. All Acceptance Criteria were met during the test.

Operational Experience Since Startup

Relief valves are inspected and tested in accordance with Technical Specification requirements.

EPU Transient Analysis Results

Relief valve operations were not analyzed. Inadvertent relief valve openings have been determined to be non-limiting events.

EPU Power Ascension Testing
Relief valves will continue to be tested in accordance with Technical Specifications. Since relief valve setpoints are not changed and relief valve operations are not impacted by CPPU, there is no need for any additional testing beyond the testing already required by Technical Specifications.

Conclusion
Technical specification testing demonstrates that relief valves function properly. Plant pressure control system stability has been consistently demonstrated during relief valve operation showing no blockages existed in relief valve discharge piping. Further in-plant testing of relief valves is not necessary.

RCIC Functional Testing

The RCIC Functional Testing startup test verifies the proper operation of the RCIC system at the minimum and rated operating pressures and flow ranges and demonstrates reliability in automatic mode starting with cold standby when reactor is at power conditions. The test is demonstrated by two methods: (1) by flow injection into a test line that leads to the Condensate Storage Tank (CST) and (2) by flow injection directly into the reactor vessel. Acceptance Criteria was satisfied for the RCIC Functional Test during startup testing and therefore further testing is not necessary.

Startup Test Objectives
The objectives for RCIC functional testing startup tests are: (1) demonstrate the proper operation of the Reactor Core Isolation Cooling (RCIC) System over its expected operating pressure and flow ranges; and (2) demonstrate RCIC reliability in automatic starting from cold standby when the reactor is at power conditions. The Acceptance Criteria and testing methods for RCIC Functional Testing are described in FSAR 14.2.

Startup Test Results
All Acceptance Criteria for startup RCIC Functional testing was satisfied for Unit 1 and Unit 2.

Demonstrate the Proper Operation of the Reactor Core Isolation Cooling (RCIC) System over its Expected Operating Pressure and Flow Ranges

- Unit 1: All Acceptance Criteria was satisfied. The RCIC system demonstrated its reliability by never tripping or isolating during testing and by always achieving rated flow within the allowed 30 seconds. The few minor problems that did occur were Level 2 Acceptance Criteria failures and were adequately dispositioned.

- Unit 2: All Acceptance Criteria was satisfied. The RCIC system demonstrated its reliability by always achieving rated flow within the allowed 30 seconds, and by never tripping during auto start tests. The turbine did trip once during a manual start, which was attributed to air in the servo control valve following maintenance to the control valve. The other minor problems that did occur were all Level 2 Acceptance Criteria failures and were adequately dispositioned.

Demonstrate RCIC Reliability in Automatic Starting from Cold Standby when the Reactor is at Power Conditions

- Unit 1: All Acceptance Criteria was satisfied. The RCIC system demonstrated its reliability by never tripping or isolating during testing and by always achieving rated flow within the allowed 30 seconds. The few minor problems that did occur were all Level 2 Acceptance Criteria failures and adequately dispositioned.

- Unit 2: All Acceptance Criteria was satisfied. The RCIC system demonstrated its reliability by always achieving rated flow within the allowed 30 seconds, and by never tripping during auto start tests. The turbine did trip once during a manual start, which was attributed to air in the servo control valve following maintenance to the control valve. The other minor problems that did occur were all Level 2 Acceptance Criteria failures and were adequately dispositioned.

Conclusion

Based on plant historical data and EPU analytical results, proper operation of the RCIC system at the minimum and rated operating pressures was achieved and flow ranges demonstrated reliability in automatic mode starting with cold standby when reactor is at power conditions and therefore further plant testing of RCIC Functional Testing is not necessary.

EPU Reactor Core Isolation Cooling System Evaluation

The RCIC system does not change for CPPU. Pressures, flow rates, and response times are virtually identical. Consequently, the RCIC system is not evaluated other than as it contributes to mitigation of other anticipated transients and events.

Operational Experience Since Startup

During operational events since startup, RCIC has provided acceptable performance when required to function by operational events.

EPU Power Ascension Testing

RCIC testing during EPU power ascension testing is not required because the CPPU changes do not have a significant impact on the RCIC system. Specifically, system pressures, temperatures, flow rates, and timing requirements remain unchanged from CLTP requirements. Therefore, RCIC testing would not provide any new data, particularly with regard to overall plant safety significance. RCIC testing in accordance with Technical Specification requirements remains a sufficient demonstration of RCIC capability.

HPCI Functional Testing

The High Pressure Coolant Injection ("HPCI") Functional Testing startup test verifies the proper operation of the HPCI system at the minimum and rated operating pressures and flow ranges and demonstrates reliability in automatic mode starting with cold standby when reactor is at power conditions. The test is demonstrated by two methods: (1) by flow injection into a test line that leads to the Condensate Storage Tank (CST) and (2) by flow injection directly into the reactor vessel. Acceptance Criteria was satisfied for the HPCI Functional Test during startup testing and therefore further testing is not necessary.

Startup Test Objectives

The objectives for HPCI functional testing startup tests are: (1) demonstrate the proper operation of the HPCI system over its expected operating pressure and flow ranges; and (2) demonstrate HPCI reliability in automatic starting from cold standby when the reactor is at power conditions. The Acceptance Criteria and testing methods for HPCI Functional Testing are described in FSAR 14.2.

Startup Test Results
All Acceptance Criteria for startup HPCI Functional testing was satisfied for Unit 1 and Unit 2.

Demonstrate the Proper Operation of the High Pressure Coolant Injection (HPCI) System over its Expected Operating Pressure and Flow Ranges.

- Unit 1: The HPCI system demonstrated its reliability by never tripping or isolating during testing and by achieving rated flow within the allowed 25 seconds in nine out of ten tests. In the tenth test, ST 15.1 on 1-1-83, the system started in 25.1 seconds with flow exceeding the 4900 gpm during the interval between 17 and 25 seconds. Evaluation by General Electric determined that the results were acceptable.

  Some problems were experienced in tuning the HPCI flow controller. Difficulty was experienced in trying to find the optimum controller settings so that the system would start in 25 seconds but not trip, yet would still be stable for step changes in flow demand. As a result, ST 15.1 and 15.2 had to be repeated.

- Unit 2: Testing of the HPCI system can be divided into two phases, before and after pre-commercial outage. Prior to the pre-commercial outage the HPCI system demonstrated its reliability by never tripping or isolating during testing and by achieving rated flow within the allowed 25 seconds in five out of six tests. In the sixth test, ST 15.3 on 9-25-84, the system required 26.3 seconds to achieve rated flow. The Tech Spec limit of 30 seconds was not violated. Investigation into the problem resulted in an Environmental Upgrade Modification and a replacement of the mechanical overspeed trip mechanism. The Environmental Upgrade Modification involved replacing the EGR, the servo on the control valves, the temperature control valve on the lube oil cooler and the turbine trip solenoid valve and was done during the Pre-commercial Operations Outage.

  The two other problems that did occur were both Level 2 Acceptance Criteria failures. The initial run of ST 15.1 yielded a subsequent speed peak of 4440 rpm, which was above the limit of 4336 rpm. The HPCI flow controller was tuned, and since ST 15.1 at 150# had already been run, ST 15.1 was repeated at both 150# and rated pressure. The other problem which also surfaced during the initial test concerned a low NPSH value caused by the startup strainer never being removed from the suction line. Upon removal, the NPSH value was acceptable.

  All acceptance criteria were satisfied except for the time to rated flow failure mentioned previously.

Conclusion
Based on plant historical data and EPU analytical results, proper operation of the HPCI system at the minimum and rated operating pressures was achieved and flow ranges demonstrated reliability in automatic mode starting with cold standby when reactor is at power conditions and therefore further plant testing of HPCI Functional Testing is not necessary.

EPU High Pressure Coolant Injection System Evaluation
The HPCI system does not change for CPPU. Pressures, flow rates, and response times are virtually identical. Consequently, the HPCI system is not evaluated other than as it contributes to mitigation of other anticipated transients and events.

<u>Operational Experience Since Startup</u>
During operational events since startup, HPCI has provided acceptable performance when required to function by operational events.

<u>EPU Power Ascension Testing</u>
HPCI testing during EPU power ascension testing is not required because the CPPU changes do not have a significant impact on the HPCI system. Specifically, system pressures, temperatures, flow rates, and timing requirements remain unchanged from CLTP requirements. Therefore, HPCI testing would not provide any new data, particularly with regard to overall plant safety significance. HPCI testing in accordance with Technical Specification requirements remains a sufficient demonstration of HPCI capability.

5.0 Operator Training/Large Transient Simulations

For EPU, SSES plans to benchmark its simulator to conform to EPU transient analysis results and to subsequently perform certification tests to confirm the adequacy of simulation of the various transients. Once the simulator is benchmarked and certified, SSES operators will be trained on various plant upset conditions, from postulated accident conditions to anticipated transients. In this way, plant operators will be prepared for the nature, timeline, and extent of the plant response to simulated transients.

6.0 Large Transient Testing Risk Assessment

SSES conducted a risk assessment for performing two plant transient tests upon EPU implementation. The evaluated tests were a generator full load reject and an MSIV isolation event. The risk assessment indicated the proposed tests represented an increase in the risk of core damage and large early release. This assessment does not include the potential for equipment damage or challenges to the operators, which should be avoided.

<u>Method</u>
The calculations were performed with the FEB05RA version of the SSES PRA. The Conditional Core Damage Probabilities (CCDPs) were calculated by multiplying the random maintenance model Core Damage Frequency (CDF) from the pre-EPU model by the Fussell-Vesely of the initiator and dividing that product by the frequency of the initiator. The Fussell-Vesely represents the fractional contribution to the damage state from the event occurring.

<u>PRA Results</u>
Below are the data extracted from the cut set file. The LOOP frequency is from the Initiating Event Note Book.

	CDF	LERF
Base	2.95E-06	1.18E-06

	Fussell-Vesely * CDF (FV)	Fussell-Vesely * LERF (FV)	Initiating Event Frequency / year
Non-isolation event	1.88E-01	8.64E-02	8.90E-01
Isolation event (MSIVC)	2.80E-02	4.47E-02	1.36E-01
Recirc Suction side LOCA	5.90E-02	1.33E-02	3.81E-04
LOOP	5.56E-01	6.28E-01	2.98E-02

CCDPa = CDFbase * FVa / Fa (similar formula for CLERPa)		
Initiator	CCDP	CLERP
Non-isolation event	6.24E-07	1.15E-07
Isolation event (MSIVC)	6.08E-07	3.88E-07
Recirc Suction side LOCA	4.57E-04	4.13E-05
LOOP	5.51E-05	2.49E-05

* FV is the fraction of core damage attributable to the specific event.

Conclusion

The Conditional Core Damage Probabilities (CCDP) and Conditional Large Early Release Probabilities (CLERP) for a turbine trip (%1NONISO) and for a MSIV closure event (%1ISO) are relatively small compared to events such as the LOOP or a suction side LOCA. However, they do have some risk significance.

The calculated CCDPs are 6.24E-7 and 6.08E-7 for the non-isolation (turbine trip) and isolation (MSIV closure), respectively. Also, the calculated CLERPs are 1.15E-7 and 3.88E-7 for the non-isolation (turbine trip) and isolation (MSIV closure), respectively. These CCDPs and CLERPs represent the additional probabilities of core damage and large early release, caused by performing the proposed tests (i.e., the initiating events occur). If both tests are performed, the total additional probabilities would, thus, be 1.23E-6 (CCDP) and 5.03E-7 (CLERP). [Note: The analyses do not credit compensatory measures that may reduce the risk of core damage given that extra operators may be staged for the proposed tests.]

In view of the foregoing and from a PRA perspective, Large Transient Testing should not be performed unless clear benefits can be achieved that cannot otherwise be obtained through an unplanned event.

7.0 Post EPU Industry Experience

Post EPU Steam Dryer Issues

Steam dryer failures have occurred at post EPU conditions. These failures have been attributed to high cycle fatigue stresses that result from acoustic and pressure pulses caused by the higher EPU main steam velocities. Problems that have occurred are the result of long term cyclic pulses that fatigue areas of high stress intensities. They do not result from transient events except to the extent that the lifting of safety relief valves can add to main steam velocities. In the case of Large Transient Testing; however, safety relief valves typically lift because the MSIVs have closed with the result being that steam velocities are actually lower and not higher. Also, with fatigue as the failure mechanism, even increased velocities are not significant in that they do not last for extended periods of time.

Stresses imposed on steam dryers by the higher steam flows are being addressed in Attachment 10 of the SSES EPU application, and therefore will not be repeated here. At the same time, it should be noted that steam dryer performance is not demonstrated by Large Transient Testing. Steam dryer stresses can be determined by finite element analyses using pressure and acoustic data developed from strain gauge and acoustic measurements in the main steam lines. Should dryer failures occur, they can be observed by changes in main steam flows, steam line pressure drops, and high moisture carryover content. Dryer failures would not be indicated in Large Transient Testing because even if abnormal measurements were to occur during a transient test, they would be masked by the transient and would not stand out as an indication of dryer problems.

Industry Post EPU Transient Events

A review of industry transient events that occurred at greater than original power levels at BWR-4 units that are similar in design to SSES resulted in the following examples of plant response to MSIV closure and load reject events. As indicated in the examples below, the plants responded as expected in accordance with their design features. No unexpected conditions were experienced nor were any latent defects uncovered in these events beyond the specific failures that actually initiated the events. These events provide further evidence that Large Transient Testing is unnecessary.

Edwin I. Hatch Nuclear Plant - 13% Approved Power Uprate
LER 99-05
On May 5, 1999, Hatch Unit 2 was at 98.3% of rated power (2,716 CMWT). At that time, the turbine tripped when the main generator tripped on a ground fault. The reactor scrammed and the reactor recirculation pumps tripped automatically on turbine control valve fast closure caused by the turbine trip. The reactor feed water pumps maintained water level higher than eight inches above instrument zero. No safety system actuations on low level were received nor were any required. Pressure reached a maximum value of 1,124 psig. Plant and system responses were as expected.

LER 2000-004
On July 10,2000, Hatch Unit 1 was at 99.7% rated thermal power (2,754 CMWT). At that time, the main turbine tripped when the vibration instrument on the main generator exciter outboard bearing failed and produced a false high bearing vibration signal. The reactor automatically scrammed and the reactor recirculation pumps automatically tripped on turbine stop valve fast closure caused by the main turbine trip. All systems functioned as expected and given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level never decreased to the Level 3 actuation setpoint. No safety system actuations were received nor were any required.

LER 2001-02
On March 28, 2001, Plant Hatch Unit 1 was at 100 percent rated thermal power (2,763 CMWT). At that time, the reactor automatically scrammed on turbine control valve fast closure caused by a main turbine trip. The main turbine tripped when actuation of phase two and phase three differential relays monitoring a unit auxiliary transformer resulted in actuation of a lockout relay. Actuation of this lockout relay generated a direct turbine trip signal and the main turbine tripped per design.

Reactor Feedwater Pumps recovered reactor vessel water level within 30 seconds of the scram. As a result, the HPCI and RCIC system low water level initiation signals cleared before either system could inject makeup water to the reactor vessel. Vessel pressure reached a maximum value of 1,127 psig after receipt of the scram. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient.

Brunswick Steam Electric Plant – 20% Approved Power Uprate

LER 2003-01

On January 12, 2003, Brunswick Steam Electric Plant Unit 1 was operating at 94% rated thermal power. Decreasing reactor coolant level due to a reactor feed water pump turbine trip resulted in the actuation of the reactor protection system, and a Group 2 and Group 6 primary containment isolation valves closures. After the plant trip, the (4) emergency diesel generators started due to an invalid signal generated by switchyard equipment. In addition, the Reactor Core Isolation Cooling system was manually operated to maintain coolant level in the reactor vessel. The loss of the reactor feed water pump was attributed to insufficient lube oil pressure margin in the bearing oil header.

The required equipment responded as designed and the Group 2 and 6 valves isolated. All control rods fully inserted into the core. However, a power circuit breaker in the 230 kV electrical power system did not open initially as designed to separate the main transformer and generator from the grid. This caused an invalid signal that resulted in the start of the emergency diesel generators after the turbine generator trip.

LER 2003-04

On November 4, 2003, Brunswick Steam Electric Plant Unit 2 was operating at approximately 96% of rated thermal power when a generator/turbine trip occurred due to loss of generator excitation. Approximately three seconds into the voltage transient, the Unit 2 generator/turbine tripped, resulting in RPS actuation. The voltage decrease also resulted in PCIS Valve Group 1 (Main Steam Isolation valves (MSIVs), Main Steam Line Drain valves, and Reactor Recirculation Sample valves), Group 3 (Reactor Water Cleanup isolation valves), and Group 6 (Containment Atmosphere Control/Dilution, Containment Atmosphere Monitoring, and Post Accident Sampling System isolation valves) isolations.

All control rods fully inserted into the core. Plant response to the transient also resulted in High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) System actuations on low reactor pressure vessel (RPV) coolant level, with injection into the RPV. All four Emergency Diesel Generators (EDGs) automatically started but did not load because electrical power was not lost to the emergency buses.

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-1	Chemical & Radiochemical: This test secures information on the chemistry and radiochemistry of reactor coolant and verifies that sampling equipment, procedures, and techniques meet specifications and requirements.	19% 27% 54% 69% 97% TC1-3 TC 5 TC-6	Y	Y	Secured information on chemistry and radiochemistry in the uprate condition.	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.			X	X	X	X	X
ST-2	Radiation Measurements: This test determines background radiation levels in plant environs prior to operation for base data on activity buildup and monitors radiation at selected power levels to assure the protection of personnel during plant operation.	17% 47% 100% TC 1 TC 3 TC 6	Y	Y	At the uprate power level, gamma dose and neutron dose rate measurements were made at pre-designated locations to identify and assess the impact of the SSES uprate.	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.			X	X	X	X	X
ST-3	Fuel Loading: The objective of this test is to achieve the full and proper core complement of nuclear fuel assemblies through a safe and efficient fuel loading evolution.	--	Y	Y	Fuel loading was performed in accordance with plant procedures.	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.	X						
ST-4	Full Core Shutdown Margin: The purpose of this test is to demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.	--	Y	Y	Shutdown margin checks were performed	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.	X						

[4] See the Notes at the end of Table 1 for definitions of Test Conditions

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-5	Control Rod Drive System: The objectives of this test are (1) demonstrate the system operates properly over the full range of primary coolant temperatures and pressures from ambient to operating and (2) determine the initial operating characteristics of the entire CRD system.	TC 1 TC 3 TC 6	Y	Y	CRD dynamic friction determined within limits and acceptable scram times verified.	Yes	CRD dynamic friction to be determined within limits and acceptable scram times verified.	X						
ST-6	SRM Performance and Control Rod Sequence: This test demonstrates operational sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe, efficient manner for each specific rod withdrawal sequence.	--	Y	N[5]	As in FSAR 14.2.12.6, testing originally contained in this test was merged into test 10.	None	This startup test was merged into Test #10							
ST-7	Reactor Water Cleanup System: This test is to demonstrate specific aspects of the mechanical operability of the Reactor Water Cleanup System.	TC 3	Y	Y	Not necessary to retest. Modifications were made to this system prior to power uprate. Post modification testing was successful.	None	Not necessary to retest.							
ST-8	Residual Heat Removal System: This test shows the ability of the Residual Heat Removal System to (1) remove heat from the reactor system for refueling and nuclear system servicing and condense steam while the reactor is isolated from the main condenser.	96% TC 6	Y	Y	Not necessary to retest. Satisfied by verifying the RHR HX capacity was greater than or equal to design. Steam condensing mode of the RHR system has been eliminated.	None.	Not necessary to retest.							

[5] By the time of Unit 2 startup testing, ST-6 had been merged into ST-10. Hence the test was accomplished with ST-10.

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-9	Water Level Measurement: This test determines actual reference leg temperature and recalibrates instruments if necessary and to verify consistent response of the upset range, narrow range and wide range level instrumentation.	TC1-6 21% 40% 44%* 73%* 69% 99%	Y	Y	Not necessary to retest. The small, correction for the small increase in drywell temperature was negligible.	None.	Not necessary to retest.							
ST-10	IRM Performance: The objective of this test is to adjust the Intermediate Range Monitor System to obtain the desired overlap with the SRM and APRM systems.		Y	Y	Not necessary to retest. Operational sources have been removed from the core. Several startups have been successfully completed. IRM overlap with SRMs and APRMs are routinely performed per procedures..	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.	X						
ST-11	Local Power Range Monitoring System Calibration: The objective of this test is to calibrate the LPRM System.	TC 2 TC 3 TC 6	Y	Y	LPRMs were calibrated	Yes EPU M515	None. Test will be performed. See Table 3 for details.	X						
ST-12	Average Power Range Monitoring System: The objective of this test is to calibrate the APRM system.	18.2% 39% 71.4% 69% 97% 99.9% TC 1 TC 2 TC 3 TC 5 TC 6	Y	Y	APRMs were calibrated per the weekly schedule	Yes EPU task T1005	None. Test will be performed.	X						

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-13	<u>NSSS Process Computer</u>: The objective of this test is to verify the NSSS performance of the process computer under plant operating condition.	TC 2 TC 3	Y	Y	Further testing unnecessary since computer functions were not changed.	None.	Not necessary to retest.							
ST-14	<u>Reactor Core Isolation Cooling System:</u> This test verifies the proper operation of the RCIC system at the minimum and rated operating pressures and flow ranges and demonstrates reliability in automatic mode starting with cold standby when reactor is at power conditions.	TC 2 TC-3	Y	Y	RCIC manual start at 150 psig reactor pressure	Testing beyond normal surveillance not required	Test is not required. CPPU does not cause any changes to RCIC system. Pressures, temperatures, flow rates, and timing requirements are unchanged. See PUSAR Supplement Section 4.3 for further justification.							
ST-15	<u>High Pressure Coolant Injection</u>: This test verifies the proper operation of HPCI system at the minimum and rated operating pressures and flow ranges and demonstrates reliability in automatic mode starting from cold standby when the reactor is at rated pressure conditions.	TC 2 TC 3 TC 4	Y	Y	HPCI slow manual start followed by an auto quick start at 150 psig reactor pressure	Testing beyond normal surveillance not required	Test is not required. CPPU does not cause any changes to HPCI system. Pressures, temperatures, flow rates, and timing requirements are unchanged. See PUSAR Supplement Section 4.3 for further justification.							
ST-16	<u>Selected Process Temperatures</u>: This test establishes the proper setting of the low speed limiter for recirculation pumps to avoid coolant temperature stratification in the reactor pressure vessel bottom head region.	TC 3 TC 4 TC 6	Y	Y	Not necessary to retest. The low speed limiter is not being changed,. No recirculation pump trips planned. Reactor pressure vessel bottom head regions temperature data during recirculation pump trips are routinely collected and analyzed per existing plant procedures.	None	Not necessary to retest. The low speed limiter is not being changed,. No recirculation pump trips planned. Reactor pressure vessel bottom head regions temperature data during recirculation pump trips are routinely collected and analyzed per existing plant procedures.							

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-17	<u>System Expansion</u>: This test demonstrates that reactor recirculation, main steam inside containment, and the piping systems in Table 3.9-33 respond to thermal expansion consistent with stress analysis results.	TC-2 TC-3 TC 6	Y	Y	Not necessary to retest. Power uprate increases the temperature of primary system piping by 5°F. The increase is negligible with respect to the thermal expansion of piping that ranges from 70° to 550°F.	None	Not necessary to retest. Power uprate temperature increases of primary system piping is negligible with respect to the thermal expansion of piping that ranges from 70° to 550°F .(there are no changes in primary system temperature except for a FW temp increase of 10°F).							
ST-18	<u>TIP Uncertainty</u>: This test determines the uncertainty of the TIP system readings.	TC 3 TC 6 65.8% 97.4%	Y	Y	This test is performed after each refueling outage at 100% power	Yes	This test is normally performed after each refueling outage after attaining 100% power.							X
ST-19	<u>Core Performance</u>: This test (1) evaluates the core thermal power and (2) evaluates the following core performance parameters: (i) maximum linear heat general rate, (ii) minimum critical power ratio, and (iii) maximum average planar linear heat general rate.	TC 1 thru TC 6 65.5% 46% 69% 95% 99%	Y	Y	Steady state core thermal power measurements at 90% and 100% of original power and then at 3% power intervals up to new rating	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.		X	X	X	X	X	X
ST-20	<u>Steam Production Verification</u>: This test demonstrates that NSSS is providing steam sufficient to satisfy all appropriate warranties.	99.7%	Y	N	Not necessary to retest. There are no warranties associated with steam production for power uprate. Power uprate warranties are tested in Test 50.	None	Not required. Power uprate warranties will be tested elsewhere							
ST-21	<u>Core Power-Void Mode Response</u>: This test verifies the stability of the core power-void dynamic response.	TC4 TC-6	Y	Y	Not necessary to retest. Operation in regions of high core power-void dynamic response is governed by the plant technical specifications.	None	Operation in the instability region is governed by the plant technical specifications.							

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-22	Pressure Regulator: This test demonstrates the takeover capability of the backup pressure regulator upon failure of the controlling pressure regulator and to demonstrate smooth pressure control transition between the control valves and bypass valves when reactor steam generation exceeds steam flow used by the turbine.	43% 60% 63% 75% 97% 100% TC1-6	Y	Y	Step changes and simulated regulator failures were demonstrated	Yes EPU task T1005	None. Test will be performed. See Table 3 for details.	X		X		X		X
ST-23	Feedwater System: The objectives of this test are: (1) demonstrate acceptable response to the feedwater control system for reactor water level control, (2) to demonstrate stable reactor response to subcooling changes, (3) to demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of the one feedwater pump, and (4) to demonstrate the maximum feedpump runout capability is compatible with licensing assumptions.	45% 75% 97% TC1-6	Y	Y	Feedwater testing was performed but not loss of feedwater heating, feed pump trip, or feed runout testing	Yes EPU task T1005	Test will be performed. See Table 3 for details. However, feedwater pump trip and loss of feedwater heating will not be performed. See PUSAR Supplement, Section 4.3, Justification for Elimination of Power Ascension Tests		X	X	X	X	X	X
ST-24	Turbine Valve Surveillance: This test shows acceptable procedures and maximum power levels for periodic surveillance testing of the main turbine control, stop, intercept and bypass valves without producing a reactor scram.	TC 3 TC 5 TC 6 56% 69% 100%	Y	Y	Turbine control valve testing was performed	Yes EPU task T1005	None. Test will be performed. See Table 3 for testing details.		X	X	X	X	X	X

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-25	Main Steam Isolation Valves: This test functionally checks the main steam isolation valves for proper operation at selected power levels, determines reactor transient behavior during and following simultaneous full closure of all MSIVs, determines isolation valve closure time and determines the maximum power at which a single valve closure can be made without a scram.	56% 69% 86% ST-5 ST-6	Y	Y	MSIV surveillance testing was performed. Closure of all MSIV transient event was not tested	All MSIV closure event will not be tested	See PUSAR Supplement, Section 4.3, Justification for Elimination of Power Ascension Tests [Note: MSIV surveillance testing (functionality and closure times of individual valves) will be performed. MSIV testing is performed during shutdown for a refueling outage or during an outage after MSIV maintenance.]							
ST-26	Relief Valves: This test verifies that the relief valves function properly, reseat properly after operation, and contain no major blockages in the relief valve discharge piping.	TC 2	Y	Y	New safety valve set points set and tested at an approved safety/relief valve test facility.	Normal surveillance testing	Safety relief valve set points will be tested in accordance with normal surveillance requirements							
ST-27	Turbine Trip and Generator Load Rejection: The objective of this test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator.	TC 3 TC 6 75% 75% 98% 100%	Y	Y	Test results proved that the analysis tools were conservative. Since the increase in power level is small, a repeat of the test is not warranted.	Testing Not Required	See PUSAR Supplement, Section 4.3, Justification for Elimination of Power Ascension Tests							
ST-28	Shutdown from Outside the Main Control Room: This test is to demonstrate that the reactor can be shutdown, maintained in a hot shutdown condition, and cooled down from outside the main control room. The adequacy of the Emergency Operating Procedures will be verified also.	TC 1 19%	Y	Y	Power uprate does not change the capability of the plant to shut down from outside the main control room, nor does it alter the function or intent of the emergency operating procedures.	None	Power uprate does not change the capability of the plant to shut down from outside the main control room, nor does it alter the function or intent of the emergency operating procedures							

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4] RTP	Startup Test Unit[4] U 1	Startup Test Unit[4] U 2	3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP) <90	90	100	103	107	110	EPU
ST-29	Recirculation Flow Control System: The tests objectives are: (1) demonstrate the flow control capability of the plant over the entire pump speed range including individual local manual and combined master manual operation and (2) determine that all electrical compensators and controllers are set for desired system performance and stability.	TC 2 TC 3 TC 5 TC 6 40% 70% 74% 98%	Y	Y	Recirculation flow control was tested	Yes	Recirculation flow control system was changed to a manual system. There is no special feedback loop. Control testing is not necessary. Scoop tube positioner HSS will be reset and tested					X		X
ST-30	Recirculation System: The tests objectives are: (1) obtain recirculation system performance data during pump trip, flow coastdown and pump restart; (2) verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip and associated scram; (3) record and verify acceptable performance of the recirculation two pump circuit trip system; (4) verify the adequacy of the recirculation runback to mitigate a scram, and (5) verify that no recirculation system cavitation will occur in the operable region of the power-flow map.	TC 3 TC 6 70% 75%	Y	Y	Power uprate has no effect that will alter the ability of the recirculation system to satisfy these objectives.	Testing Not Required	See PUSAR Supplement, Section 4.3, Justification for Elimination of Power Ascension Tests							

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-31	<u>Loss of Turbine Generator and Off-site Power</u>: This test determines that the required safety system will initiate and function properly without manual assistance, the electrical distribution and diesel generator systems will function properly, and the HPCI and/or RCIC systems will maintain water level if necessary during a simultaneous loss of main turbine generator and offsite power.	TC 2 45%	Y	Y	Not necessary to retest. Power uprate does not change the ability of the safety systems to initiate and function properly nor change the ability of the electrical distribution and diesel generator systems to function properly.	Testing Not Required	Not necessary to retest. Power uprate does not change the ability of the safety systems to initiate and function properly nor change the ability of the electrical distribution and diesel generator systems to function properly.							
ST-32	<u>Containment Atmosphere and Main Steam Tunnel Cooling</u>: This test verifies the ability of the drywell coolers/recirculation fans and the reactor building portion of the main steam tunnel coolers to maintain design conditions in the drywell and reactor building portion of the main-steam tunnel, respectively, during operating conditions and post scram conditions. This test also demonstrates that containment main steam-line penetrations do not overheat adjacent concrete.	97% TC 2 TC 3 TC 5 TC 6	Y	Y	Measurements were taken to assure temperatures remained below TS limits	Yes	Measurements will be taken to assure temperatures remain below TS limits. No EPU changes are being made that would affect drywell air distribution.			X		X		X
ST-33	<u>Piping Steady State Vibration</u>: The test demonstrates that steady state vibration levels on reactor recirculation and main steam inside containment are within acceptable limits. (*Note: This test includes piping* previously contained in ST-40. Dynamic transient vibration testing previously contained in this test have been merged into ST-39).	50% 75% 100% TC2 TC3 TC6	Y	Y	Not necessary to retest. The increase in flow for power uprate does not significantly change vibration levels of this piping.	Yes	Piping vibration measurements will be taken as appropriate to demonstrate piping adequacy.	X	X	X	X	X	X	X

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-34	<u>Control Rod Sequence Exchange</u>: The objective of this test is to perform a representative sequence exchange of control rod patterns at the power level at which such exchanges will be done during plant operation and demonstrate that core limits and PCIOMR threshold limits will not be exceeded.	70% TC-3	Y	N	Not necessary to retest. Plant personnel and procedures have demonstrated the capability of rod sequence exchange without exceeding limits.	None	Not necessary to retest. Plant personnel and procedures have demonstrated the capability of rod sequence exchange without exceeding limits.							
ST-35	<u>Recirculation System Flow Calibration</u>: The objective of this test is to perform a complete calibration of the installed recirculation system flow instrumentation.	TC3 TC6* 61% 75% 98% 100%	Y	Y	Recirculation flow data taken and flow instruments recalibrated	Yes	Recirculation flow data will be taken and flow instruments will be recalibrated as needed	X				X		X
ST-36	<u>Cooling Water Systems</u>: This test is to verify that the performance of the Reactor Building Closed Cooling Water, the Turbine Building Closed Cooling Water, and Service Water Systems are adequate with the reactor at rated temperature.	TC1 TC2 TC3 TC6	Y	N	Not necessary to retest. Heat loads do not change significantly for power uprate. The systems operate within their design.	Yes	Temperature measurements will be taken as necessary to confirm EPU analyses			X	X	X	X	X
ST-37	<u>Gaseous Radwaste System</u>: This test demonstrates that the Gaseous Radwaste System operates within the Technical Specification and design limits during a full range of plant power operation and to demonstrate the proper operation of the containment nitrogen inerting system during plant operation.	TC1 TC3 TC5 TC6 20% 60% 69% 97%	Y	Y	Secured information on offgas system effluents and demonstrated that gaseous and particulate effluents satisfied acceptance criteria.	Yes	Data will be recorded to confirm acceptance criteria			X	X	X	X	X

TABLE 1 – Comparison of SSES initial startup testing and planned EPU testing

Original Test No.	Original Test Description [UFSAR Section 14.2]	Startup Test Unit[4]			3441 MWt Uprate Testing [UFSAR 14.3]	Testing Planned for CPPU	Evaluation/ Justification/Notes	CPPU Test Conditions Percent of 3489 MWt (CLTP)						
		RTP	U 1	U 2				<90	90	100	103	107	110	EPU
ST-38	<u>BOP Piping System Expansion</u>: The system expansion testing previously contained in this test has been merged into ST-17.	--	N	N	N/A Test merged into ST-17	None	Test merged into ST-17. ST-17 is not necessary since. Power uprate temperature increase is negligible with respect to the thermal expansion of piping that ranges from 70° to 550°F .(there are no changes in primary system temperature except for a FW temp increase of 10°F).							
ST-39	<u>Piping Vibration During Dynamic Transients</u>: This test demonstrates that vibration levels on main steam inside containment and reactor meet acceptable limits during selected dynamic transients.	TC2 TC3 TC6 25% 38% 75% 100%	Y	Y	Not necessary to retest. The small increase in initial power level from power uprate does not significantly change the response of this piping to dynamic transients.	No	Dynamic transients are not being performed							
ST-40	<u>BOP Piping Steady State Vibration</u>: The steady state vibration testing previously contained in this test has been merged into ST-33.		Y	N	N/A. Test merged into ST-33	Yes	Merged into test ST-33							

<u>Notes for Table 1</u>

TC 1 Core thermal power between approximately 5% and 20% rated. Recirculation pump speed within +10% of minimum pump speed. Before and after main generator synchronization.
TC 2 Core thermal power between 45% power rod line and 75% power rod line. Recirculation pump speed between minimum and lowest pump speed corresponding to Master Manual Mode. Lower power corner is within Bypass valve capacity.
TC 3 Core thermal power between 45% power rod line and 75% power rod line. Total core flow between 80% and 100% rated.
TC 4 On the natural circulation core flow line within +0, -5% of the intersection with the 100% power rod line.
TC 5 Core thermal power within +0, -5% of the 100% power rod line. Recirculation pump speed within +5% of the minimum recirculation pump speed corresponding to Master Manual Mode.
TC 6 Core thermal power between 95% and 100% rated. Total Core flow +0, -5% rated core flow.

TABLE 2 – Modification List

Title	Description	Unit 1 / Common Install	Unit 2 Install	Anticipated Post-Modification Testing
2005 - 2008 INSTALLATIONS				
I & C MODIFICATIONS				
Vibration/Acoustic Monitoring	• Install accelerometers on Main Steam, Reactor Recirculation, RHR and RWCU Lines for vibration monitoring • Install instrumentation on main steam lines for steam dryer acoustic wave monitoring	2006 U114RIO	2005 U212RIO	Instrument functional checks
Neutron Monitoring System Settings	• APRM Flow-biased SCRAM • APRM Flow-biased Rod Block • APRM Upscale Setdown SCRAM • RBM Power-based Rod Blocks	2008 U115RIO	2007 U213RIO	Instrument functional checks and surveillance tests
Power Range Neutron Monitor System	• Replace existing GE analog system with GE digital NUMAC system [Provided for completeness only. NRC approval has been requested in a separate, prior submittal]	2006 U114RIO	2007 U213RIO	Logic system functional checks
ARTS/MELLLA	• Revise the APRM flow-biased scram and rod block trip setpoints [Provided for completeness only. NRC approval has been requested in a separate, prior submittal]	2006 Post Outage	2007 U213RIO	Setpoint functional checks
EHC System	• Install accumulators on Turbine Control Valve EHC FAS lines • Install Steam Line Resonance Cards on pressure transmitter loops to dampen 3rd harmonic frequency • Modify Turbine Control Valve Digital Positioning Cards • Recalibrate the Power Load Unbalance circuit	2008 U115RIO	2007 U213RIO	EHC functional checks and Pressure Regulator Testing
MSIV High Flow Isolation Setpoint	• Revise setpoint for EPU conditions (this will require new switches)	2008 U115RIO	2007 U213RIO	Calibration and functional checks

TABLE 2 – Modification List

Title	Description	Unit 1 / Common Install	Unit 2 Install	Anticipated Post-Modification Testing
Reactor Recirculation Runback Limiter #2	•Logic change	2008 U115RIO	2007 U213RIO	Calibration and functional checks
HP Turbine Instrument Change	• RPS Scram Bypass • RWM Setpoints • RSCS Setpoints • Power Dependent Condenser High Pressure Alarm Power Signal	2008 U115RIO	2007 U213RIO	Calibration and functional checks
Reactor Feedpump Low Suction Pressure	• Revise setpoints for EPU conditions	2008 U115RIO	2007 U213RIO	Calibration and functional checks
Instrument Calibration and Computer Software Changes	• Recalibrate instruments and revise software for EPU conditions	2008 U115RIO	2007 U213RIO	Calibration and functional checks

TABLE 2 – Modification List

Title	Description	Unit 1 / Common Install	Unit 2 Install	Anticipated Post-Modification Testing
MECHANICAL MODIFICATIONS				
Reactor Feedpump Seal Water	• Revise Temperature Control Valve settings per vendor recommendation • Revise drain line vent piping for increased drain flow	2006 U114RIO	2007 U213RIO	Calibration and functional checks
Cross Around Relief Valve Set Point Change	• Revise setpoint for EPU conditions • Revise design pressure of associated piping for EPU conditions • Replace relief line expansion joints for EPU steam flow conditions	2006 U114RIO	2007 U213RIO	Relief valve lift/reseat testing
High Pressure Turbine	• Replace the High Pressure Turbine for increased steam flow at EPU conditions	2008 U115RIO	2007 U213RIO	125% rotor speed factory test Transient/steady state data recording Over-speed trip testing
Condensate Pump Impellers	• Replace Condensate Pump Impellers for increased flow at EPU conditions • Replace minimum flow valve internals to allow a larger minimum flow • Replace MOVs on pump discharge valves • Revise relief valve settings	2008 U115RIO	2007 U213RIO	Pump performance testing Head versus flow measurements, System Transient Testing.
#5 Feed Water Heaters	• Increase design pressure and increase shell relief valve setpoints	2008 U115RIO	2007 U213RIO	Pressure testing
Standby Liquid Control Boron Enrichment	• Replace existing sodium pentaborate solution • Modify system logic to allow for single pump initiation	2008 U115RIO	2007 U213RIO	Pressure/flow rate testing TS surveillance testing
Circ Water Box Vents	• Add automatic Circulating Water Box vent valves to prevent air binding of condenser tubes	2008 U115RIO	2007 U213RIO	Performance tests

TABLE 2 – Modification List

Title	Description	Unit 1 / Common Install	Unit 2 Install	Anticipated Post-Modification Testing
Ultimate Heat Sink	• Install a second isolation valve, manually operated, in each of two Spray pond Spray Header Bypass Lines to reduce the effects of a single bypass line isolation failure-to-close under accident conditions • Reduce number of large array nozzles to improve efficiency	2006 Post Outage	NA	Performance tests Piping pressure tests/leak tests Valve performance tests
Hydrogen Water Chemistry Flow	• Increase hydrogen, oxygen and zinc injection flows due to increased feedwater flow rate under EPU conditions.	2008 U115RIO	2007 U213RIO	Flow rate measurements
EPU Implementation	• Configuration modification for EPU implementation. No physical work involved.	2008 U115RIO	2007 U213RIO	As per EPU startup testing
Acid Injection	• Provide additional acid injection capability for the Cooling Tower basin.	2008 U115RIO	2007 U213RIO	Flow rate measurements
#3 FWH Emergency Dump Valves	• Replace valves for EPU conditions	2008 U115RIO	2007 U213RIO	Performance testing
Reactor Feed Pump Turbines	• Replace all three Reactor Feed Pump Turbines due to higher turbine speeds required at EPU conditions • Upgrade turbine speed controls and overspeed trip to digital controls	2010 U116RIO	2009 U214RIO	Functional performance tests Overspeed/trip testing Piping leakage and integrity testing, System Transient Testing.
Condensate Demineralizer	•Install an 8th Condensate Demineralizer to maintain Condensate water quality under increased EPU flow conditions	2010 U116RIO	2009 U214RIO	Flow rate testing; Hydrostatic Testing; Piping leakage and integrity testing
Condensate Filter	• Install a 7th Condensate Filter to maintain Condensate water quality under increased EPU flow conditions	2010 U116RIO	2009 U214RIO	Flow rate testing; Hydrostatic Testing; Piping leakage and integrity testing
ESW to Fuel Pool Check Valve	• Valve change to reduce mission dose for post-LOCA manual action	2006 Post Outage	N/A	Flow rate testing; Hydrostatic Testing; Piping leakage and integrity testing

TABLE 2 – Modification List

Title	Description	Unit 1 / Common Install	Unit 2 Install	Anticipated Post-Modification Testing
Feedwater Heaters	• Changes to manage velocity and tube vibration issues at EPU conditions	2010 U116RIO	2009 U214RIO	System flush and flow rate testing Hydrostatic Testing Piping leakage and integrity testing
Potential EQ Changes	• As required for EPU environmental conditions	2008 U115RIO	2007 U213RIO	As Required
Appendix R RHR Pump Logic Change	• Logic change and raceway protection to eliminate fire-induced failure mechanisms • Provide cross-divisional cooling to RHR pump motor coolers	2008 U115RIO	2007 U213RIO	Logic functional test
CIVIL / PIPING MODIFICATIONS				
RFP Suction Piping Modification	• Replace suction flanges, revise piping design pressure, revise relief valve setpoints	2008 U115RIO	2007 U213RIO	Non-Destructive Examination Piping integrity/pressure tests as required
Main Steam, Feedwater and Extraction Steam Piping Supports	• Revise piping supports as necessary for EPU conditions	2008 U115RIO	2007 U213RIO	Non-Destructive Examination Piping integrity/pressure tests as required
Gaseous Radwaste Recombiner Drain Piping	• Revise drain piping configuration for increased EPU flow conditions	2008 U115RIO	2007 U213RIO	Non-Destructive Examination Piping integrity/pressure tests

TABLE 2 – Modification List

Title	Description	Unit 1 / Common Install	Unit 2 Install	Anticipated Post-Modification Testing
ELECTRICAL MODIFICATIONS				
Power Distribution/Switchyard	• Install new switchyard capacitor banks to meet PJM reactive power requirements for generators • Replace Unit 1 Sync breaker and associated controls with a breaker having a higher amperage rating • Uprate Unit 2 main transformers and change tap settings to meet EPU conditions	<u>2008</u> U115RIO	<u>2007</u> U213RIO	Performance testing as required

TABLE 3 - Planned Tests

Title	Test Number	Test Description
Chemistry & Radiochemistry	Test No. 1	Samples are taken and measured at EPU power levels to determine the chemical and radiochemical quality of reactor water, thermodynamic steam quality (moisture carryover) feed water, and gaseous effluent.
Radiation Measurements	Test No. 2	Gamma dose rate and neutron dose rate measurements are taken at specific limiting locations (where appropriate) at various EPU levels. These measurements assess the effect uprate has on actual plant area dose rates. FSAR radiation zones are monitored for required changes.
Fuel Load	Test No. 3	Fuel loading shall be performed per plant procedures and the FACCTAS. The FACCTAS is prepared according to RE-081-042, FACCTAS Preparation Guidelines for Refueling Outages. Core Verification is performed according to RE-081-036, Core Post-Alteration Verification.
Full Core Shutdown Margin	Test No. 4	Full core shutdown margin demonstration shall be performed per reactor engineering surveillance procedures SR-100-008 (SR-200-008), In-Sequence Critical and Shutdown Margin Demonstration.
Control Rod Drive System	Test No. 5	CRD dynamic friction determined to be within limits prior to startup and acceptable scram times verified at normal TS surveillance intervals.
IRM Performance	Test No. 10	After the APRM calibration for EPU, the IRM gains are adjusted as necessary to assure the IRM overlap with the APRMs.
LPRM Calibration	Test No. 11	The LPRM channels are calibrated to make the LPRM readings proportional to the neutron flux in the LPRM water gap at the chamber elevation. Calibration factors are obtained through an offline or a process computer calculation that relates the LPRM reading to the average fuel assembly power at chamber height.
APRM / RBM	Test No. 12A Test No. 12B	<u>APRM</u>: Confirms the calibration of APRMs consistent with the rated thermal power, referenced to CLTP, as determined from the heat balance. Assures that the APRM flow-biased scram and rod block setpoints in the power range neutron monitors are consistent with MELLLA operation by confirming/adjusting the drive flow gain in neutron monitors during power ascension and at rated power, so that the drive flow normalization conditions (i.e. 100% drive flow is equal to 100% core flow at 100% power) is satisfied. Confirms all APRM trips and alarms prior to entering the MELLLA region. <u>RBM</u>: Confirms that the power range neutron monitor RBM power based setpoints have been changed to the ARTS values and the RBM has been calibrated consistent with Technical Specifications. Verifies that the RBM adjustments have been properly set for the RBM
TIP Uncertainty	Test No. 18	This test is normally performed at 100% power after each refueling outage upon reaching 100% power.
Core Performance	Test No. 19	Routine measurements of reactor parameters are taken near 90% and 100% of CLTP and extrapolated to the next power step up to maximum EPU power. Core thermal power and core performance parameters are calculated using accepted methods to ensure current licensed and operational practices are maintained. Power is increased using control rods and core flow in incremental steps of 5% or less to ensure a careful, monitored approach to maximum EPU power. Measured reactor parameters and calculated core performance parameters are utilized to project those values at the next power level step. Each step's actual values are satisfactorily confirmed with the projected values for that step before advancing to the next step and the final confirmation is at

TABLE 3 - Planned Tests

Title	Test Number	Test Description
		the maximum EPU power level.
Pressure Regulator	Test No. 22	The pressure regulator requires only the following changes for EPU: (1) Those settings identified in Task T0700, Turbine Generator Performance Evaluations (2) Task T0502, Pressure Control System, (i.e. Pressure Regulator Setpoint), (3) The EHC modification of Table 2, and (4) Confirming the dynamic tuning parameters. Before EPU, while the plant is shutdown, the pressure regulator system will tested and dynamically calibrated. GE Service Information Letter (SIL) No. 589 (Ref. 4.1) discusses the tuning of the dynamic parameters for the pressure regulator. Pressure control system response to pressure set point change is tested at various test conditions. Testing the system requires a 10 psi down set point change followed by a 10 psi up setpoint change when conditions stabilize. Pressure regulators are tested individually and sequentially.
Feedwater System	Test No. 23	Feedwater control system response to reactor water level set point changes (for level set point change tests) are evaluated in the indicated control mode (i.e. three element, single element).. Changes are made only after conditions stabilize in accordance with the following set point change sequence. (1) + 2 inches (3) + 3 inches (5) + 4(+ or –1") inches (2) – 2 inches (4) – 3 inches (6) – 4(+ or –1") inches The 2 and 3 inch level set point steps are informational and recommended to demonstrate the level control response prior to performing the formal level set point steps (i.e. 4(+ or –1) inch). The results from the informational level set point steps are utilized to anticipate the responses to the formal demonstration test steps, so that effects on the reactor may be anticipated (i.e. power increases, level alarms). The tolerance of the formal level step (i.e. 4(+ or –1) inch) permits adjustment to take into consideration the limit cycles of the control mode being tested. If the limit cycles are small enough to permit the formal steps to be at the lower end of the tolerance (i.e. 3 inches), then the informational 3 inch steps need not be performed. The normal feed water control system mode is three-element control, with single element control only being used for temporary backup situations. The feed water control system in three-element control mode should be adjusted, not only for stable operational transient level control (i.e. decay ratio), but also for stable steady state level control (i.e. minimize reactor water limit cycles). In single element control mode, the system adjustments must achieve the operational transient level control criteria, but for steady state level control the temporary backup nature of this mode should be considered. For tests calling for manual flow step changes, at each test condition the feed water control system is placed in a manual/auto configuration (i.e. one feed water pump in manual and the other in automatic). Flow step changes are made by inserting the step demand change into the feed water pump controller in manual or by changing the set point of that controller in accordance with the following set point change sequence (expressed in percent of rated EPU feed water flow). After completion of testing on one controller, the manual/auto configuration is switched and the sequence is repeated on the other controller.

TABLE 3 - Planned Tests

Title	Test Number	Test Description
		(1) Increase 5% (2) Decrease 5% (3) Increase 10% (4) Decrease 10% The 5% flow step changes are informational and recommended to demonstrate the feed water turbine response prior to performing the formal test flow step changes (i.e. + or –10%). The results from the smaller informational flow steps are used to anticipate the responses to the formal demonstration tests and any effects on the reactor (i.e. level changes, power increases).
Turbine Valve Surveillance	Test No. 24	Initial tests are performed (using the original STS methodology) near and at two points below the power level at which each valve's surveillance has been performed in pre-EPU uprate tests. Maximum power test condition is determined by projecting the initial test's scram/trip set point margins to the highest power level where all the margins are acceptable. Final tests are performed at this maximum power test condition (within fuel preconditioning limits) to confirm acceptable test performance. Proximity to vessel pressure is closely monitored in neutron and heat flux scrams and also main steam line high flow isolation trip. Each test is manually initiated, valve stroked, and reset in accordance with the current valve surveillance procedure.
MSIV Surveillance	Test No. 25	Surveillance test performed during outage.
Recirculation Flow Control	Test No. 29	Scoop tube positioner high speed stops will be reset because more recirc pump flow will be needed to produce 108 Mlb/hr core flow. The new HSS will be tested.
Containment Atmosphere and Main Steam Tunnel Cooling	Test No. 32	Measurements will be taken to assure temperatures remain below TS limits.
Piping Steady State Vibration	Test No. 33	Piping vibration measurements will be taken as appropriate to demonstrate piping and support adequacy.
Recirculation Flow Control Calibration	Test No. 35	Recirculation system data will be recorded to calibrate core flow at EPU conditions
Cooling Water Sytems	Test No. 36	Temperature measurements will be taken as necessary to confirm EPU analyses
Gaseous Radwaste System	Test No. 37	Data will be recorded to confirm acceptance criteria.
MS & Feed Piping Vibrations	Test No. 100	During EPU power ascension, designated main steam and feedwater piping points (i.e. location and direction) are monitored for vibration. Vibration monitoring points are designated based on EPU piping vibration analysis and engineering judgment. Monitoring points may be coincidental with those in the initial startup piping vibration test or selected as those points with the highest predicted vibration. Vibrations monitoring points can be coincidental, with exposed piping attachments, provided that acceptance criteria is established for those points based on piping system vibration analysis. Vibration measurements taken above CLTP will permit a thorough assessment of the effect of the EPU in comparison to any previous piping vibration analysis or evaluation.

TABLE 3 - Planned Tests

Plant Parameter Monitoring	Test No. 101	Routine measurements of the power dependant parameters from systems and components affected by the EPU are taken near 90% and 100% of CLTP and extrapolated to the next power step up to maximum EPU power. Power is increased using control rods and core flow in incremental steps of 5% or less to ensure a careful and monitored approach to maximum EPU power. Power dependant parameters are calculated to ensure current licensed and operational practice is maintained by using accepted methods. Measured and calculated power dependant parameters are utilized to project those values at the next power level step prior to increasing to the next EPU test condition. Each step's projected values will be evaluated to have satisfactorily confirmed the actual values before advancing to the next step and the final increase to maximum EPU power.
Condensate Pump Trip	Test No. 102	One condensate pump will be tripped from a power level of 3733 MWt (+0, -5%) during the startup test program for the first uprate step on the first unit. If the results of that trip deviate significantly from the predicted results, a condensate pump trip will be repeated from the 3952 MWt (+0, -5%) power level during the startup test program for the second uprate step on the first unit.

10

Attachment 9 to PLA-6076

Flow Induced Vibration
Piping / Components Evaluation

Table of Contents

1. Purpose

The purpose of this attachment is to provide information in addition to that presented in the Power Uprate Safety Analysis Report (PUSAR) section 3.4, regarding the susceptibility review of plant system piping and components that might be affected adversely by Flow Induced Vibration (FIV) under Constant Pressure Power Uprate (CPPU) conditions.

Reactor Internal Components are not addressed in this attachment. PUSAR, section 3.4.2 provides a discussion of the FIV effects on Reactor Internal Components.

2. Background

PPL Susquehanna, LLC (PPL) intends to implement a 14% of Original License Thermal Power (OLTP) CPPU above the Current License Thermal Power (CLTP) of 1.06*OLTP. The implementation is planned in two increments that extend over two refueling outages for each unit. This conservative implementation plan minimizes the potential for significant changes in flow induced vibration (FIV) to cause degradation of plant components. This approach permits plant walkdowns and inspections of CPPU affected systems before and after each power increase.

In November 2004 the BWR Owners' Group (BWROG) issued NEDO 33159, "CPPU Lessons Learned and Recommendations," (Reference 1) to provide assistance to plants that are in the evaluation and implementation phases of a CPPU. As part of the CPPU implementation strategy, Susquehanna Steam Electric Station (SSES) is following the recommendations of the BWROG in order to minimize CPPU impacts on plant reliability. PPL intends to continue its involvement in industry efforts and consideration of on-going issues associated with FIV. Lessons learned will be evaluated and incorporated into the SSES implementation strategy as applicable.

The increase in flow resulting from CPPU is expected to result in higher vibration accelerations in some piping and piping components. The types of vibration that are of concern are structural resonance, acoustic standing waves, vortex shedding, rotating equipment excitation at the pump vane passing frequency, and fluid-elastic stability in heat exchangers. This attachment identifies those systems & components where CPPU is expected to increase the susceptibility to FIV, describes the methods to determine the CPPU effects and the actions to address potential problem areas.

3. Extent of Condition (EOC) Review

SSES has performed both an internal and external EOC review for vibration related issues to confirm that planned CPPU actions are adequate to address those issues already identified by either SSES maintenance or industry experience. The internal review involved a document review of SSES piping and attached components vibration history, including calculations.

The external review concentrated on a review of industry databases relating to piping and component vibration, and the BWROG generic recommendations for implementing CPPU with respect to increased FIV.

The following is the process that was used to identify systems affected by FIV:

A. Identified those SSES systems that are expected to see a flow change due to CPPU or as determined in the correlated review in paragraph E.
B. Determined expected maximum increase in flow rate due to CPPU. See Section 5 for more detailed discussion.
C. Identified those SSES systems, components, and documents with previous or existing vibration issues.
D. Reviewed the following external databases for systems and components with previous vibrations issues:
    a. INPO Significant Event Reports (SER's) and Operating Experience (OE's);
    b. NRC Information Notices;
E. Correlated SSES maintenance history documents to the BWROG recommended actions. Estimated the susceptibility of the SSES piping and components to FIV at CPPU conditions.

Table 1 - EOC Estimation of Susceptibility to FIV Using Plant Maintenance History, Industry Reviews, and BWROG Recommendations

A	B	C	D	E
SYSTEM	FLOW CHANGE	EXISTING VIBRATION	INDUSTRY VIBRATION	SUSCEPTIBILITY TO FIV AT CPPU
Circulating Water	0 %	X	X	X
Condensate	15 %	X	X	X
EHC	(2)	X	X	X
Extraction Steam	16 %	X	X	X
Feedwater (IC)	15 %	None	None	X
Feedwater (OC)	15 %	X	X	X
HPCI Steam	(2)	X	X	X
Main Steam (IC)	14 %	None	X	X
Main Steam (OC)	14 %	X	X	X
RCIC Steam	(2)	None	X	X
Recirculation/RHR	3 %	X	X	X
Turbine Piping	14 %	X	X	X
Sample Probes (1)	15 %	None	X	X
Snubbers (1)	15 %	X	X	X

(1) These components were found to be sensitive to FIV in numerous plant systems. See sections 12 and 13 of this attachment for an additional discussion.
(2) Flow change is 0 % but their attachment to the main steam line piping warranted investigating their susceptibility to FIV at CPPU conditions.
(3) X indicates the system has one, or more, piping/components susceptible to FIV.
(4) (IC) Inside Containment, (OC) Outside Containment

4. SSES Plant Personnel Vibration Inputs

PPL has placed an emphasis on involving plant and office personnel who are knowledgeable with FIV issues. In the fall of 2004, General Electric interviewed a number of SSES personnel. The discussions focused on system existing conditions, likely CPPU effects, and recommendations to improve both. PPL has evaluated these results.

In the fall 2005 key plant operations support groups listed areas where SSES might be vulnerable to FIV. In addition to the known issues, the following are representative of new topics identified:

- Main Turbine steam admission valve limit switches,
- Main Steam line vibration (broken support mounting bolts), and
- Rack Mounted Instruments (e.g. Reactor Protection System).

Both the known and the new topics are included in the CPPU FIV evaluation plan.

5. Review of CPPU System Changes as They Affect FIV

The Reactor Coolant Pressure Boundary (RCPB) and Balance of Plant (BOP) piping systems were reviewed, and the systems that have significant changes in flow as a result of CPPU are: Main Steam, Feedwater, Condensate, Feedwater Heater Drains, and Extraction Steam. CPPU maximum flows increase and the potential increases in FIV, which can increase by the square of the flow increase, are summarized as follows:

Table 2- SSES Piping Systems with Large Flow Changes

Item	Piping System	CLTP Flow (Mlb/hr)	CPPU Flow (Mlb/hr)	$\frac{\text{CPPU-CLTP}}{\text{CLTP}}$ (%)	Increase In Vibration Levels $[(\text{CPPU/CLTP})^2 - 1]$ (%)
1	Main Steam	14.84	16.98	14	30%
2	Feedwater/Condensate	14.85	17.03	15	32%
3	Extraction Steam	1.23	1.42	16	34%
4	FW Heater Drains	6.00	6.86	15	31%

6. Vibration Acceptance Criteria

ASME Codes associated with safety related nuclear power plant piping require vibration testing and monitoring of this important plant piping during initial operation at new and higher flow rates. The steady state level of piping FIV is expected to increase from current levels in proportion to the change in fluid density (ρ) and fluid flow velocity (V) squared or (ρV^2). The large diameter piping (>2 in) in the affected systems is reviewed for the impact of this increase on stresses. Small diameter branch piping also is susceptible to cracking at socket welded connections and is reviewed for changes in header flow velocity and the resulting vibration frequency change.

Vibration acceptance criteria are included in the CPPU power ascension program. The methodology of ASME O/M-S/G Part 3, "Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems," is used. The criteria in this industry standard are based on the material endurance limit, which assumes an unlimited number of load cycles. The piping systems expected to be impacted the most significantly by CPPU implementation are identified. For the portions of these systems inside the drywell, which will not be accessible during plant operation, detailed piping computer models were created. Response spectrum modal superposition analyses were run, which identified the natural frequencies, mode shapes, and resulting pipe displacements and accelerations. Locations and directions for the accelerometers were selected based on the locations of maximum vibration acceleration and displacement. Baseline vibration data was collected prior to CPPU implementation. Acceleration vs. frequency curves were developed from this data and extrapolated to expected CPPU levels. The piping analyses were then re-run using these curves, and the results scaled up until the endurance limit is reached. A number of conservatisms were incorporated in the process to allow for uncertainty and provide extra margin. The resulting vibration spectra are used as initial acceptance criteria.

For accessible systems outside containment, systems less affected by CPPU, and small bore piping; generic vibration screening allowables are used. Most of the piping outside containment will be screened for vibration by walkdown and measurement with portable equipment.

Vibration monitoring will be performed during startup at plateaus beginning with 75% of the CLTP and proceeding at varying increments to CPPU. This will allow trending of the data and will identify whether a condition other than final CPPU data results in the highest vibration levels. Direction is provided in the test program for plant personnel in the event that vibration limits are exceeded. If required, power will be reduced to the previous levels until further evaluation can be performed.

7. Types of Vibration Monitoring

The piping systems located inside containment are being monitored for vibration using accelerometers, and the data is collected on dedicated data acquisition computers. The piping systems located outside containment generally will be monitored using portable vibration instrumentation, with data collected during walkdowns of the piping, and with remote vibration monitoring sensors in inaccessible areas. Remote operated cameras are an alternative to pipe mounted vibration instrumentation to provide plant and engineering personnel with qualitative feedback on flow induced vibration of piping and associated components. Ongoing evaluations to determine whether additional monitoring is needed are in progress. Additional monitoring instrumentation will be installed if initial measurements indicate that screening criteria could be exceeded.

The following systems are monitored with remote vibration instrumentation:

1) Main Steam
2) Feedwater
3) Recirculation (for non-CPPU vibration issues)
4) RHR
5) Extraction Steam

Other Systems are monitored with localized, or portable vibration instrumentation:

1) Condensate
2) HPCI (outside containment)
3) Electro Hydraulic Control (EHC)
4) Feedwater Heater Drains

As previously described in section 6, the locations and directions of accelerometers are selected based on maximum analysis stress results at CLTP conditions and at known FIV susceptible locations such as the Safety Relief Valves (SRVs) that are discussed in section 11. Since the FIV monitoring is performed at CLTP conditions, CPPU flow simulated (during Main Steam Isolation Valve (MSIV) slow-closure testing) conditions, and CPPU conditions, any increase in FIV results will be clearly identified and evaluated.

The following table summarizes the instrumentation installed, or planned to be installed, to monitor FIV. See the Appendices of this attachment for additional details regarding sensor locations.

Table 3 - Monitoring Currently Installed & Planned For Installation

System	Unit 1 # Locations / # Accelerometers	Unit 2 (2) # Locations / # Accelerometers
Main Steam	**6 / 18**	**6 / 16**
Feedwater	**5 / 11**	5 / 11
Recirculation/RHR (Inside Containment)	**18 / 27**	**12** + 6 / **16** + 11
RHR (Outside Containment)	**4 / 20**	**4 / 20**
Extraction Steam 4th Stage	**3 / 8** (3)	Under Review

Notes:

1. **Bold items are currently installed**
2. Accelerometers not currently installed in Unit 2 will be installed by April, 2007.
3. These accelerometers were installed to address the expected increases in vibration due to the Turbine Replacement Project during 2002. They will be active through the CPPU startup program.

8. Vibration Monitoring Results to Date

Vibration data has been collected from the accelerometers installed in Unit 1 since Spring 2006 and in Unit 2 since Spring 2005. The data has been compared to the screening values for those lines and the results summarized in the table below.

The vibration data from the Unit 1 Extraction Steam accelerometers was also collected and evaluated prior to 2005 and the results summarized in the table below.

Table 4 - Measured Vibration Accelerations - % of Calculated Screening Criteria

System	Unit 1	Unit 2
Main Steam	40%	30 %
Feedwater	45%	(1)
Recirculation/RHR	60%	60%
Extraction Steam	40 %	(2)

Notes:
1. Accelerometers to be installed March, 2007. Data to be available later in 2007
2. System is being evaluated to determine if accelerometers are needed

The recirculation/RHR results are higher than those associated with the main steam & feedwater systems. These vibration levels reflect the system response to recirculation pump vane passing frequencies. Since the recirculation flow increases less than 3%, operation at CPPU is not expected to cause vibration levels to increase above screening criteria. Based on the existing system behavior, including the above measured accelerations, and experience at other plants, it is expected that the feedwater system vibration levels at CPPU will not exceed screening criteria.

In April, 2006 PPL performed MSIV slow closure tests for each of the A, B, C, D Outboard MSIVs at the 80% Power Level. During these tests, the main steam flow through each of the open MSIVs was equal to a flow that will exist at about the first implementation step of the CPPU (~ 1.13 OLTP). The Root Mean Square (RMS) and Peak accelerations were recorded. The maximum RMS value is listed below and compared to the maximum CLTP values and the increase is slightly smaller than the predicted ratio of 1.14 determined from the square of the velocity increase discussed in Section 6. For simplicity the velocity change is assumed proportional to the square of the Power Ratio, $[(1.13/1.06)^2]$.

Table 4A - Measured Vibration Maximum Accelerations (G's) - Unit 1 Main Steam Lines Comparison of CLTP to Simulated ½ of CPPU (MSIV Slow Closure Tests)

RMS at CLTP CONDITIONS = 1.06 OLTP	RMS at Test CONDITIONS = 1.13 OLTP	Measured Increase	Predicted Increase
.074	.081	1.10	1.14

The above results are considered relatively low for the main steam system, and the vibration levels after implementation of CPPU are not expected to exceed screening criteria.

9. Inspections and Walkdowns

Since vibration instrumentation is neither practical nor desirable for all systems, visual inspections are a key part of PPL's CPPU FIV evaluation strategy. Walkdowns are planned in 4 major CPPU phases; pre-CPPU, CPPU first step (7%), CPPU second step (7%), and, CPPU post implementation. The following systems will have walkdowns scheduled: main steam, feedwater, condensate, extraction steam, feedwater heater drains, main turbine EHC, and HPCI steam (outside containment).

The reactor recirculation system is currently remotely monitored for FIV and inspected every outage. Since the increase in CPPU flow for the recirc system is small (2% to 3%), the inspections routinely performed on the system are adequate for CPPU implementation.

Each planned walkdown inspection criteria includes the following:

- Condition of insulation on subject and adjacent pipes,
- Condition of pipe supports,
- Piping,
- Attached components and branch lines,
- Condition of structures and components adjacent and below, and
- Other specific criteria for particular systems.

10. Modifications

Programs are in place, and in some instances implemented, to reduce the susceptibility of piping to FIV. These programs include the following:

- Socket welds on small pipe attached to the recirculation lines are inspected to more stringent criteria than was used during original construction. If the existing welds do not meet the upgraded criteria, the welds are repaired or replaced with an improved socket weld design,
- Capped piping small pipe attached to the recirculation lines has been removed and the connection plugged,

- Modifications of the RHR 050A/B check valves that attach to recirculation piping,
- Supports have been added to feedwater heater drain lines,
- Mechanical snubbers have been replaced on the steam seal evaporator lines by Wire Energy Absorbing Restraints, and
- Mechanical snubbers to be replaced with more vibration resistant hydraulic snubbers on the RWCU and steam seal piping.

Modifications are needed to address the increased effects of FIV at CPPU conditions. One example is the EHC system, which is being modified to add accumulators in accordance with existing GE recommendations to reduce susceptibility to fatigue. Other modifications may be identified as additional vibration data becomes available. Vibration monitoring and walkdown programs will identify those areas susceptible to FIV and trend their data to determine whether CPPU could lead to the exceedence of screening criteria. Engineering evaluations of the data will determine whether additional physical modifications will be needed.

Of special concern for FIV susceptibility tracking and trending is the identification of piping/components that already have frequent replacement rates, and whose CPPU response could require replacement in less than the current 2 year operating cycle schedule. Table 5 lists examples of components with frequent replacement rates and the expected change due to CPPU.

Table 5 – Piping/Components with Frequent Replacement Rates

A	B	C	D	E	F
COMPONENT	**ITEM**	**SYSTEM**	**FLOW CHANGE Due to CPPU**	**EXISTING REPLACEMENT RATE**	**EXPECTED REPLACEMENT RATE WITH CPPU**
1. Check valves	Soft Seats	Feedwater	15 %	Every 2 years	Every 2 years
2. Butterfly Valve	Entire valve	Service Water to Stator Cooling	0 %	Every Outage	Every Outage
3. Valves	Torque on Valve Packing	HPCI and RCIC Drains	0 %	Re-torque every Outage	Re-torque every Outage
4. Air Operated Valves	Valve Bodies & Controller Linkages	Feedwater Heater Drains & Extraction Steam	16 %	2 yr diagnostic/ 6 yr rebuild	Rebuild frequency may increase

11. Valves

Industry reviews have shown that valves can be sensitive to FIV. Information Notice 2005-23 (Reference 2), documenting the sensitivity of butterfly valve taper pins to FIV, is the latest in a series of notices involving valve component failures due to FIV. PPL evaluates IE Notices and salient industry events under the SSES corrective action program, and is aware of the potential for vibration loosening of valve parts. Affected components are part of maintenance inspections.

The Safety Relief Valves (SRV) on the main steam lines are a primary FIV concern for CPPU implementation. Vibration accelerometers are located on selected SRV bodies and adjacent discharge piping. Accelerometer vibration results to date, calculations using that data and extending it to CPPU conditions, and the results of scale model testing indicate that the SSES SRVs will not experience problems due to CPPU. However, PPL will monitor the results of inspections and industry activities regarding SRVs to determine if and how they may apply at SSES.

The SRVs, and other valves (that have shown a sensitivity to FIV), will be inspected for FIV degradation at each of the four planned CPPU phases discussed in section 9 of this attachment.

12. Sample Probes

There are a number of sample probes and thermowells that extend into the flow stream on the piping systems affected by CPPU (Reference 3). The probes are susceptible to vibration from vortex shedding. As the flow velocity increases, not only does the vibration magnitude increase, but also the vortex shedding frequency increases. If the new vortex shedding frequency coincides with the structural natural frequency of the probe, overstress can result.

The sample probes have been reviewed for sensitivity to CPPU flow. In most cases, the design of the probes has considerable margin. The probes will be modified during CPPU implementation if the frequencies induced by the flow approach the natural frequencies of the probes.

13. Mechanical Snubbers on Pipes

There are a number of mechanical snubbers installed as restraints on piping systems that are affected by CPPU. Some snubbers are showing signs of degradation due to FIV and the wear is expected to become more severe with the implementation of CPPU. Several mechanical snubbers have already been replaced by WEAR (Wire Energy Absorbing Rope) pipe restraint and vibration isolators. Several other mechanical snubbers are being replaced with hydraulic snubbers. The existing snubber testing plan ensures that mechanical snubber degradation is checked and corrected. If testing results deem necessary, PPL will increase the frequency of mechanical snubber inspections for those located on piping that has high FIV responses now, and those which are expected to become more severe with CPPU.

14. Conclusion

PPL has identified piping and components that are expected to be most affected by CPPU by performing a review of both industry and plant specific experience using the BWROG CPPU Extent of Condition matrix as guidance. The BWROG CPPU Extent of Condition matrix is Appendix C of NEDO 33159, "CPPU Lessons Learned and Recommendations," November 2004 (Reference 15.1).

Piping and components are being monitored with either remote vibration acceleration instrumentation, hand held vibration instrumentation, or observation programs during operation. Vibration Acceptance criteria have been defined and accelerometer data, to date, indicates that no screening criteria will be exceeded due to CPPU conditions.

Walkdowns and inspections are planned for the areas of interest during accessible times.

The analyses conclude that no actions, beyond those previously discussed in section 10, are needed at this time. However, the results of the planned data collections and walkdowns/ inspections will be reviewed to determine whether changes are needed.

The PPL FIV program for CPPU is dynamic through continuous involvement in the BWROG, monitoring industry and plant developments, collecting and evaluating vibration data, and performing modifications, if required, to stay within acceptable FIV acceptance criteria.

15. References

1. BWR Owners' Group (BWROG), "CPPU Lessons Learned and Recommendations," NEDO 33159, November 2004 .
2. NRC INFORMATION NOTICE 2005-23, "Vibration Induced Degradation of Butterfly Valves," February 10, 2005.
3. NRC INFORMATION NOTICE 2004-06, "Loss of Feedwater Isokinetic Sampling Probes at Dresden Units 2 and 3, March 26, 2004.

Appendix A1 – Vibration Accelerometers on Main Steam Piping (Unit 1)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE -16708	B	10.75	HPCI	426	Y
VE -16709	B	10.75	HPCI	426	X
VE -16710	B	10.75	HPCI	426	Z
VE -16711	B	12.75	SRV M	33G	Y
VE -16712	B	12.75	SRV M	33G	X
VE -16713	B	12.75	SRV M	33G	Z
VE -16714	B	26	B	266	Y
VE -16715	B	26	B	266	X
VE -16716	B	26	B	266	Z
VE -16717	C	4.5	RCIC	Z003	Y
VE -16718	C	4.5	RCIC	Z003	X
VE -16719	C	4.5	RCIC	Z003	Z
VE -16720	C	12.75	SRV B	53Z	Y
VE -16721	C	12.75	SRV B	53Z	X
VE -16722	C	12.75	SRV B	53Z	Z
VE -16723	C	26	C	509	Y
VE -16724	C	26	C	509	X
VE -16725	C	26	C	509	Z

Totals: 6 locations on 2 lines with 18 accelerometers

X - Horizontal, East/West
Y – Vertical
Z - Horizontal, North/South

Appendix A2 – Vibration Accelerometers on Main Steam Piping (Unit 2)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE - 26707	B	10.75	HPCI	NA	X
VE - 26708	B	10.75	HPCI	NA	Y
VE - 26709	B	10.75	HPCI	NA	Z
VE - 26710	B	12.75	SRV J	NA	X
VE - 26711	B	12.75	SRV J	NA	Z
VE - 26712	B	26	B	NA	Y
VE - 26713	B	26	B	NA	X
VE - 26714	B	26	B	NA	Z
VE - 26715	C	4.5	RCIC	NA	X
VE - 26716	C	4.5	RCIC	NA	Y
VE - 26717	C	4.5	RCIC	NA	Z
VE - 26718	C	12.75	SRV B	NA	X
VE - 26719	C	12.75	SRV B	NA	Y
VE - 26720	C	12.75	SRV B	NA	Z
VE - 26721	C	26	C	NA	X
VE - 26722	C	26	C	NA	Z

Totals: 6 locations on 2 lines with 16 accelerometers

X - Horizontal, East/West
Y – Vertical
Z - Horizontal, North/South

Appendix B1 – Vibration Accelerometers on Feedwater Piping (Unit 1)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE - 16753	DLA-101	24	DLA101-H2	18	Y
VE - 16754	DLA-102	12	Near N4F & PR-53	50	HP
VE - 16755	DLA-102	12	Near N4F & PR-53	50	HO
VE - 16756	DLA-102	12	Near N4E & PR-40	84	A
VE - 16757	DLA-102	12	Near N4E & PR-40	84	HP
VE - 16758	DLA-102	12	Near N4E & PR-40	84	HO
VE - 16759	DLA-102	12	PR-251	99	Y
VE - 16760	DLA-102	12	PR-251	99	A
VE - 16761	DLA-102	12	PR-251	99	HP
VE - 16762	DLA-102	12	Near N4D & PR-45	118	HP
VE - 16763	DLA-102	12	Near N4D & PR-45	118	HO

Totals: 5 locations on 1 line with 11 accelerometers

A – Axial, along pipe
Y – Vertical
HP - Horizontal and perpendicular to pipe
HO - Horizontal, perpendicular to pipe and to HP

Appendix B2 – Vibration Accelerometers on Feedwater Piping (Unit 2)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE-26769	DLA-201	24	On HV241F011A	NA	Y
VE-26770	DLA-202	12	Near N4F & PR-53	NA	HP
VE-26771	DLA-202	12	Near N4F & PR-53	NA	HO
VE-26772	DLA-202	12	Near N4E & PR-40	NA	A
VE-26773	DLA-202	12	Near N4E & PR-40	NA	HP
VE-26774	DLA-202	12	Near N4E & PR-40	NA	HO
VE-26775	DLA-202	12	Near PR-251	NA	Y
VE-26776	DLA-202	12	Near PR-251	NA	A
VE-26777	DLA-202	12	Near PR-251	NA	HP
VE-26778	DLA-202	12	Near N4D & PR-45	NA	HP
VE-26779	DLA-202	12	Near N4D & PR-45	NA	HO

Totals: 5 locations on 1 line with 11 accelerometers

A – Axial, along pipe
Y – Vertical
HP - Horizontal and perpendicular to pipe
HO - Horizontal, perpendicular to pipe and to HP

Appendix C1 –Vibration Accelerometers on Reactor Recirculation/RHR Piping (Unit 1) [LOOP A]

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE -16726	A	12	Below N2K nozzle	8014	HP
VE -16727	A	4	Riser of Discharge Valve Bypass Line	Z001	X
VE -16728	A	4	Bypass Line	8018	Y
VE -16729	A	4	Bypass Line Blind Flange	252	Z
VE -16730	A	4	Decontamination Connection at Blind Flange	405	HP
VE -16731	A	4	RWCU	8028	Y
VE -16732	A	2	RWCU	344	X
VE -16733	A	2	RWCU	340	Z
VE -16734	A	NA	Body of Discharge Valve	233	X
VE -16735	A	24	RHR	172	Y
VE -16736	A	24	RHR	172	HA
VE -16737	A	24	RHR	172	HP
VE -16738	A	24	RHR	186	HP
VE -16739	A	24	RHR	186	HA
VE -16740	A	NA	Body of Check Valve F050A	146	Y
VE -16741	A	NA	Body of Check Valve F050A	146	X
VE -16742	A	NA	Body of Check Valve F050A	146	Z
VE -16743	A	NA	Body of Check Valve F050A	146	ATS

Totals: 12 locations on 1 line with 18 accelerometers

ATS – Acoustic Tapping Sensor
HA - Horizontal axial
HP - Horizontal and perpendicular to pipe
HO - Horizontal, perpendicular to pipe and to HP
X - Horizontal, East/West
Y – Vertical
Z - Horizontal, North/South

Appendix C2 –Vibration Accelerometers on Reactor Recirculation/RHR Piping (Unit 1) [LOOP B]

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE -16744	B	12	Below N2E Nozzle	8014	HP
VE -16745	B	4	Riser of Discharge Valve Bypass Line	Z001	X
VE -16746	B	4	Bypass Line	794	Y
VE -16747	B	2	RWCU	808	X
VE -16748	B	2	RWCU	810	Z
VE -16749	B	NA	Body of Check Valve F050B	700	Y
VE -16750	B	NA	Body of Check Valve F050B	700	X
VE - 16751	B	NA	Body of Check Valve F050B	700	Z
VE -16752	B	NA	Body of Check Valve F050B	700	ATS

Totals: 6 locations on 1 line with 9 accelerometers

ATS – Acoustic Tapping Sensor
HP - Horizontal and perpendicular to pipe
X – East - West
Y – Vertical
Z – North - South

Appendix C3 –Vibration Accelerometers on Reactor Recirculation/RHR Piping (Unit 2) [LOOP A]

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE - 26723	A	12	Below N2K nozzle	145	HP
VE - 26724	A	4	Riser of Discharge Valve Bypass Line	580	X
VE - 26725	A	4	Bypass Line	615/620	Y
VE - 26726	A	4	Bypass Line Blind Flange	595	Z
VE - 26727	A	4	Decontamination Blind Flange	355	HP
VE - 26728	A	4	RWCU	540	Y
VE - 26729	A	2	RWCU	441	X
VE - 26730	A	2	RWCU	441	Z
VE - 26731	A	28	Pump Discharge Piping	280	X
VE - 26732	A	24	Body of Check Valve F050A	690	Y
VE - 26733	A	24	Body of Check Valve F050A	146	X
VE - 26734	A	24	Body of Check Valve F050A	146	Z
VE - 26735	A	24	RHR	760	Y
VE - 26736	A	24	RHR	760	HA
VE - 26737	A	24	RHR	760	HP
VE - 26738	A	24	RHR	784	HP
VE – 26780	A	24	RHR	784	HA
VE - 26759	A	NA	Body of Check Valve F050A	146	ATS

Totals: 12 locations on 1 line with 18 accelerometers

ATS – Acoustic Tapping Sensor
HA - Horizontal axial
HP - Horizontal and perpendicular to pipe
X – East - West
Y – Vertical
Z – North - South

Appendix C4 –Vibration Accelerometers on Reactor Recirculation/RHR Piping (Unit 2) [LOOP B]

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE-26760	B	12	Below N2E Nozzle	NA	HP
VE-26761	B	4	Riser of Discharge Valve Bypass Line	NA	X
VE-26762	B	4	Bypass Line	NA	Y
VE-26763	B	2	RWCU	NA	X
VE-26764	B	2	RWCU	NA	Z
VE-26765	B	NA	Body of Check Valve F050B	NA	Y
VE-26766	B	NA	Body of Check Valve F050B	NA	X
VE-26767	B	NA	Body of Check Valve F050B	NA	Z
VE-26768	B	NA	Body of Check Valve F050B	NA	ATS

Totals: 6 locations on 1 line with 9 accelerometers

ATS – Acoustic Tapping Sensor
HP - Horizontal and perpendicular to pipe
X – East - West
Y – Vertical
Z – North - South

Appendix D1 – Vibration accelerometers on RHR piping, Outside Containment (Unit 1)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE-16769	RHR A Shutdown	24	Valve HV151F015A	NA	HP to stem
VE-16770	RHR A Shutdown	24	Valve HV151F015A	NA	Y to stem
VE-16771	RHR A Shutdown	24	Valve HV151F015A	NA	A to stem
VE-16772	RHR A Shutdown	24	Valve HV151F015A	NA	A to pipe
VE-16773	RHR A Shutdown	24	Valve HV151F015A	NA	Y to pipe
VE-16774	RHR A Shutdown	24	Valve HV151F017A	NA	HP to stem
VE-16775	RHR A Shutdown	24	Valve HV151F017A	NA	Y to stem
VE-16776	RHR A Shutdown	24	Valve HV151F017A	NA	A to stem
VE-16777	RHR A Shutdown	24	Valve HV151F017A	NA	A to pipe
VE-16778	RHR A Shutdown	24	Valve HV151F017A	NA	Y to pipe
VE-16779	RHR B Shutdown	24	Valve HV151F015B	NA	HP to stem
VE-16780	RHR B Shutdown	24	Valve HV151F015B	NA	Y to stem
VE-16781	RHR B Shutdown	24	Valve HV151F015B	NA	A to stem
VE-16782	RHR B Shutdown	24	Valve HV151F015B	NA	A to pipe
VE-16783	RHR B Shutdown	24	Valve HV151F015A	NA	Y to pipe
VE-16784	RHR B Shutdown	24	Valve HV151F017B	NA	HP to stem
VE-16785	RHR B Shutdown	24	Valve HV151F017B	NA	Y to stem
VE-16786	RHR B Shutdown	24	Valve HV151F017B	NA	A to stem
VE-16787	RHR B Shutdown	24	Valve HV151F017B	NA	A to pipe
VE-16788	RHR B Shutdown	24	Valve HV151F017B	NA	Y to pipe

A – Axial Totals: 4 locations on 2 lines with 20 accelerometers

HP - Horizontal and perpendicular

Y – Vertical

Appendix D2 – Vibration accelerometers on RHR piping, Outside Containment (Unit 2)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE-26739	RHR A Shutdown	24	Valve HV251F015A	NA	HP to stem
VE-26740	RHR A Shutdown	24	Valve HV251F015A	NA	Y to stem
VE-26741	RHR A Shutdown	24	Valve HV251F015A	NA	A to stem
VE-26742	RHR A Shutdown	24	Valve HV251F015A	NA	A to pipe
VE-26743	RHR A Shutdown	24	Valve HV251F015A	NA	Y to pipe
VE-26744	RHR A Shutdown	24	Valve HV251F017A	NA	HP to stem
VE-26745	RHR A Shutdown	24	Valve HV251F017A	NA	Y to stem
VE-26746	RHR A Shutdown	24	Valve HV251F017A	NA	A to stem
VE-26747	RHR A Shutdown	24	Valve HV251F017A	NA	A to pipe
VE-26748	RHR A Shutdown	24	Valve HV251F017A	NA	Y to pipe
VE-26749	RHR B Shutdown	24	Valve HV251F015B	NA	HP to stem
VE-26750	RHR B Shutdown	24	Valve HV251F015B	NA	Y to stem
VE-26751	RHR B Shutdown	24	Valve HV251F015B	NA	A to stem
VE-26752	RHR B Shutdown	24	Valve HV251F015B	NA	A to pipe
VE-26753	RHR B Shutdown	24	Valve HV251F015B	NA	Y to pipe
VE-26754	RHR B Shutdown	24	Valve HV251F017B	NA	HP to stem
VE-26755	RHR B Shutdown	24	Valve HV251F017B	NA	Y to stem
VE-26756	RHR B Shutdown	24	Valve HV251F017B	NA	A to stem
VE-26757	RHR B Shutdown	24	Valve HV251F017B	NA	A to pipe
VE-26758	RHR B Shutdown	24	Valve HV251F017B	NA	Y to pipe

A – Axial Totals: 4 locations on 2 lines with 20 accelerometers

HP - Horizontal and perpendicular

Y – Vertical

Appendix E1 – Vibration accelerometers on Fourth Stage Extraction Steam Piping (Unit 1)

Accelerometer No.	Line	Pipe OD	Location	Node No.	Direction
VE-10201A	HGD-101-1	16	Between BTV10210A and PP10241A	NA	HP
VE-10202A	HGD-101-1	16	Between BTV10210A and PP10241A	NA	A
VE-10201B	HGD-101-2	16	Between BTV10210B and PP10241B	NA	HP
VE-10202B	HGD-101-2	16	Between BTV10210B and PP10241B	NA	A
VE-10203C	HGD-101-2	16	Between BTV10210C and PP10241C	NA	HP
VE-10201C	HGD-101-3	16	1 ft. from Thermowell TW10205C	NA	HP
VE-10202C	HGD-101-3	16	1 ft. from Thermowell TW10205C	NA	A
VE-10204C	HGD-101-3	16	Between BTV10210C and PP10241C	NA	A

Totals: 4 locations on 3 lines with 8 accelerometers

A – Axial, along pipe

HP - Horizontal and perpendicular

Attachment 11 to PLA-6076

Grid Stability Evaluation

PPL Susquehanna LLC
Susquehanna Steam Electric Station Units 1&2
Extended Power Up-rate

Attachment 11 SSES Grid Stability Evaluation

TRANSMISSION SYSTEM STABILITY

Studies were performed to evaluate the impact of Susquehanna Steam Electric Station (SSES) EPU operation on the transmission system stability. The proposed SSES EPU electrical generator power output is 1300 MW_e for each unit. The estimated power increases expected to be obtained from EPU and high pressure turbine replacements are 100 MW_e per unit.

ELECTRICAL SYSTEM GENERAL DESCRIPTION

The PPL Susquehanna LLC SSES, as described in this document, is composed of: two nuclear units that are connected to the PJM 230kV and 500 kV transmission systems. The units Susquehanna Unit 1 1354 MVA and Susquehanna Unit 2 1354 MVA, produce power, which is distributed through the 230kV and 500 kV system, respectively, through two (2) 500 kV transmission lines, seven (7) 230 kV transmission lines and one 500/230kv transformer. The lines are:

- 500 kV Susquehanna – Wescosville
- 500 kV Sunbury – Susquehanna
- 230 kV Susquehanna - Sunbury
- 230 kV Susquehanna - Montour
- 230 kV Susquehanna – E Palmerton
- 230 kV Susquehanna – Harwood
- 230 kV Susquehanna – Jenkins
- 230 kV Susquehanna – Stanton #1
- 230 kV Susquehanna – Stanton #2

The transformer is the 500/230kv Transformer 21 located at the Susquehanna 500kv switchyard and electrically connected between the 500kv and 230kv switchyards.

Susquehanna Transmission System

The design basis for the electric power system is described in Section 8.0 "Electric Power" of the Final Safety Analysis Report (FSAR).

"The two independent offsite electric connections to Susquehanna SES are designed to provide reliable power sources for plant auxiliary loads and the engineered safety features loads of both units such that any single failure can affect only one power supply and cannot propagate to the alternate source." (FSAR Section 8.1.1)

"Unit 1 and 2 generators are connected by separate isophase buses to their respective main step-up transformer banks. Unit 1 main step-up transformer bank, with two three-phase, half capacity power transformers, steps up the 24 kV generator voltage to 230 kV; the Unit 2 bank, with three single phase power transformers, steps up the 24 kV generator voltage to 500 kV. The step-up transformer for Unit 1 connects to the Susquehanna 230 kV switchyard and for Unit 2 to the Susquehanna 500 kV switchyard. The Susquehanna 230 kV switchyard is designed for six (6) 230 kV breaker and a half bays, and two (2) 230 kV bus." (FSAR Section 8.1.2)
"The Susquehanna 500 kV switchyard consists of three bays with double breakers, two 500 kV buses, two 500 kV lines, a 500 kV generator lead, and a 500-230 kV transformer tapped off the south bus. The Susquehanna 230 kV switchyard and 500 kV switchyard are approximately 1.9 miles apart and are interconnected by a 500-230 kV bus tie transformer and transmission line. Aerial transmission connects the Susquehanna 230 kV switchyard with Sunbury and Montour switchyards, and with Stanton, East Palmerton, Harwood, and Jenkins Substations. Aerial transmission lines integrate the Susquehanna 500 kV switchyard into the 500 kV system with connections at Wescosville, Alburtis and Sunbury. Both the Susquehanna 500 kV switchyard and the 230 kV switchyard are tied into the PJM interconnection." (FSAR Section 8.1.2)

"The plant startup and preferred power for the engineered safety features systems is provided from two independent offsite power sources shown in Dwg. D159760, Sh. 1.

a) A 230 kV line from the Susquehanna T10 230 kV switching station feeds the start-up transformer No. 10.
b) A 230 kV tap from the 500-230 kV tie line feeds the startup transformer No. 20." (FSAR Section 8.1.2)

"The bulk power transmission system of PPL operates at 230 kV and 500 kV. Unit 1 of the Susquehanna Steam Electric Station supplies power to the 230 kV system through a 230 kV switchyard and Unit 2 supplies power to the 500 kV system through a separate 500 kV switchyard. The offsite power system for the plant is supplied through the 230 kV portion of the bulk power system. "(FSAR Section 8.2.1.1)

"Two independent offsite power sources are supplied to the Susquehanna plant via Transformer T10 and second source T20, and are shared by both units. One source is supplied from the Susquehanna T10 230 kV Switchyard located to the west of the plant by constructing 4530 feet of 230 kV line on painted steel poles structures to startup transformer #10. The Switchyard consists of two breaker-and-one-half bays. A total of three 230 kV circuit breakers are electrically configured in a ring buss connecting the Montour-Susquehanna T10 230 kV line and Mountain-Susquehanna T10 230 kV line to the Unit 1 Start-up Transformer #10. "(FSAR Section 8.2.1.1)

"The two switchyards are physically separate but are tied together by a 230 kV yard tie line with a 230-500 kV transformer in the 500 kV yard.(Section 8.2.1.1)"

"Two independent offsite power sources are supplied to the Susquehanna plant via Transformers T10 and second source T20, shared by both units. One source is supplied from the Susquehanna T10 230 kV Switchyard located to the west of the plant by 4530 feet of 230 kV line on painted steel poles to startup transformer #10. The Switchyard consists of two breaker-and-one-half bays. A total of three 230 kV circuit breakers are electrically configured in a ring buss connecting the Montour-Susquehanna T10 230 kV and Mountain-Susquehanna T10 230 kV lines and the Susquehanna Transformer #10.(Section 8.2.1.1)"

"The Susquehanna T10 230 kV Switchyard is supplied by two 230 kV transmission lines, the Mountain-Susquehanna T10 and Montour-Susquehanna T10 lines. The Mountain-Susquehanna T10 line and the Montour-Susquehanna T10 230 kV line share double circuit structures from Susquehanna from the Susquehanna T10 230kV Switchyard northeast to a point where the Mountain –Susquehanna T10 230kV line branches off to the east lines share a common right of way into the Susquehanna T10 230 kV switchyard.(Section 8.2.1.1)"

"The second offsite power supply is furnished by the multiple sources throughout the bulk power grid system through the 230 kV and 500 kV lines emanating from the Susquehanna 230 kV and 500 kV switchyards. All transmission lines meet or exceed design requirements set forth by the National Electric Safety Code. One or two overhead ground wires are employed on the transmission lines above the phase conductors to provide adequate lightning flashover protection. All lines meet the Army Corps of Engineers requirements for clearance over flood levels. All bulk power transmission lines are designed to withstand 100 mph hurricane wind loads on bare conductors." (FSAR Section 8.2.1.1)

"No single disturbance in the bulk power grid system will cause complete loss of offsite power to the Susquehanna SES. This is a basic system design criteria." (FSAR Section 8.2.1.1)

Transmission Interconnection

PPL is a member of PJM, which permits exchanges of power with neighboring utilities and provides emergency assistance under Independent System Operator (ISO) direction. Direct bulk power ties are between PPL and PECO Energy (formerly Philadelphia Electric), Luzerne Electric Division of UGI, Metropolitan Edison, Pennsylvania Electric, Jersey Central Power and Light, Public Service Electric and Gas, and Baltimore Gas and Electric Companies. (FSAR Section 8.2.1.2)

ANALYSIS

The PJM bulk power system is planned in accordance with Mid-Atlantic Area Council (MAAC) Reliability Principles and Standards. MAAC is one of ten regional reliability councils of the North American Electric Reliability Council (NERC). The studies performed for Susquehanna, by PJM, tested the compliance of the system with the MAAC Reliability Principles and Standards.

The power flow portion of the analysis consisted of testing the system under normal and emergency operation conditions. The transmission system was tested under normal conditions in order to assess the transmission network element loading with the addition of the proposed upgrades. Testing included simulations of heavy power transfer conditions followed by single and multiple transmission facility outages.

Under all power flow conditions tested, the stations and the transmission system satisfy the MAAC Reliability Principles and Standards. There are some cases when the system becomes unstable during certain line or transformer outages. Case 2 below results from the impact of the Unit 2 generation increase. The other cases are base line problems irrespective of the CPPU generation increases. An Operating Guide (PPL Electric Utilities NEPA memorandum) is in place to reduce power during these specific transmission outages. The mitigating action provided by the existing Operating Guide for the Susquehanna to Wescosville line out of service addresses the newly identified Case 2 line outage condition.

Unstable cases due to line outages are:

1. **Susquehanna to Sunbury line out of service**
   3 phase fault at Susquehanna (500kV) on line between Susquehanna and Wescosville

2. **Susquehanna to Wescosville line out of service**
   3 phase fault at Sunbury on line between Sunbury and Juniata

3. **Susquehanna 500/230 KV transformer out of service**
   3 phase fault at Sunbury on line between Sunbury and Juniata

4. **Susquehanna to Wescosville line out of service**
   3 phase fault at Susquehanna (500kV) on line between Susquehanna and Sunbury

The stability analysis was conducted using the PSS/E Load Flow and Dynamic Stability software provided by Power Technologies Incorporated (done by PJM and finalized in the impact studies for queue positions M11 & M12). A key part of this regional planning protocol is the evaluation of both generation interconnection and merchant transmission interconnection requests, in this case queue position M11 and M12 were requested and approved by PJM for the additional power output.

The types of faults tested in accordance with the MAAC Criteria, Section IV, were:

1. Three (3) phase faults with normal clearing time
2. Single phase to ground faults with Breaker Failure (delayed clearing).

From a system stability point of view, faults on transmission lines around Susquehanna are more critical than a trip of either nuclear unit. Therefore, the system study considered the most critical line faults consistent with MAAC criteria.

Maximum gross MVARS limitation on the generators will cause both real time and post contingency 500 kV voltage criteria deviations when specific 500kV lines are out of service. If this occurs, options will be exhausted to correct the deviation including a generation reduction at Susquehanna, which may be required to allow MVAR reduction to relieve the voltage violation.

To accommodate the loss in reactive capability due to the increase in real power output a 183 MVAR capacitor will be installed on the 230kV substation bus and a 171 MVAR will be installed on the 500kV substation at Susquehanna (see Figure 1 for more details)

The PJM impact studies and PPL Electric Utilities NEPA memorandum provide information concerning the maximum gross MWs and MVARs output for each of the units, to maintain a stable grid operation under various system maintenance and outage conditions. These conditions include operation with one (1) and two (2) units in service and various transmission line outages. The NEPA memorandum is provided and is used by the Transmission and Distribution System Operations Center to direct the Susquehanna Control Rooms to operate the units.

Study criteria and assumptions

When dispatching power flow and determining stability limits, the following criteria are applied:

- *Steady state voltage*: pre-fault voltages at selected 500 kV buses are not above 1.1 pu or below 1.0 pu.

  In addition, the terminal bus voltages at Susquehanna Units 1 and, 2 shall not be below
  0.9 pu at the pre-fault condition.

- *Transient stability*: PJM's transient stability criteria are applied:

  The system must be stable for all faults considered

- *Damping*: post-fault system damping shall be above 3%. Considering the difficulty in applying this criterion with the tool used, only selective cases are checked, based on the engineering judgment. Therefore, *this criterion was not strictly enforced.*

- *Transient voltage*: post-fault transient voltages at 500 kV buses shall not be below 0.7 pu.

CONCLUSION

The study described above provides the following conclusions:

1. The power system is stable for all three-phase and single-phase faults studied, when cleared by primary protection in accordance with planned relay settings.

2. Power system stability was confirmed for all cases of faults, which were cleared by primary protection.

3. The Susquehanna bus stability and continued availability was confirmed.

In summary, PPL concludes that the effects of the proposed Susquehanna EPU on the offsite electrical power system will not affect the ability to meet the requirements of GDC 17. The Susquehanna units remain stable for all normal design configurations and will also remain stable for all maintenance out of service configurations provided that they are operated within the limits allowed by the Electric Utilities memorandum NEPA.

Susquehanna 500kV & 230kV

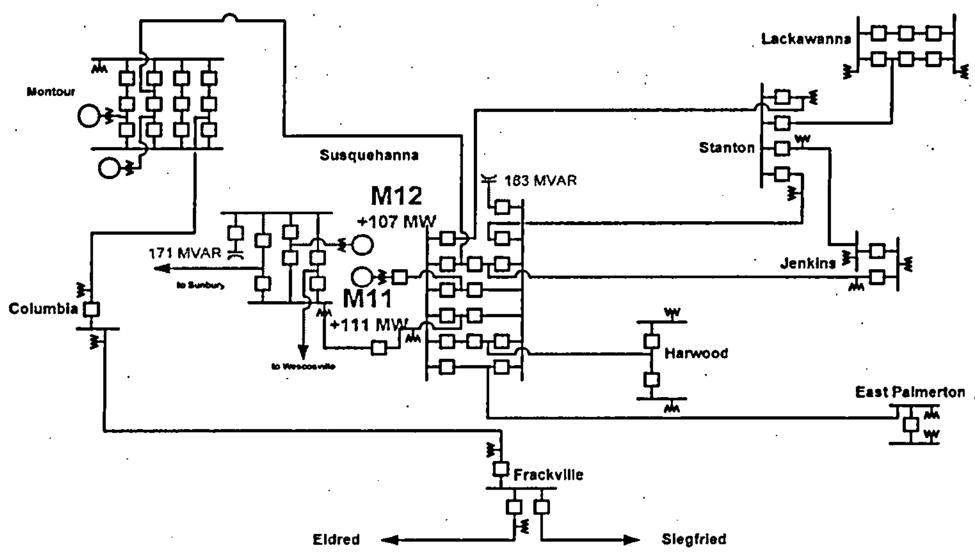


Figure 1

Attachment 12 to PLA-6076

RS-001 Standard Review Plan Correlation Matrices

MATRIX 1
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Materials and Chemical Engineering

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Reactor Vessel Material Surveillance Program	All EPUs	EMCB	SRXB	5.3.1 Draft Rev. 2 April 1996	GDC-14 GDC-31 10 CFR Part 50, App. H 10 CFR 50.60	RG 1.190	2.1.1	2.1.1	3.2.1	3.2.1	5.3.1
Pressure-Temperature Limits and Upper-Shelf Energy	All EPUs	EMCB	SRXB	5.3.2 Draft Rev. 2 April 1996	GDC-14 GDC-31 10 CFR Part 50, App. G 10 CFR 50.60	RG 1.161 RG 1.190 RG 1.99	2.1.2	2.1.2	3.2.1	3.2.1	5.3.2
Pressurized Thermal Shock	PWR EPUs	EMCB	SRXB	5.3.2 Draft Rev. 2 April 1996	GDC-14 GDC-31 10 CFR 50.61	RG 1.190 RG 1.154		2.1.3	N/A for BWRs		
Reactor Internal and Core Support Materials	All EPUs	EMCB	SRXB	4.5.2 Draft Rev. 3 April 1996	GDC-1 10 CFR 50.55a	Note 1*	2.1.3	2.1.4	10.7	10.7	4.5.2

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Reactor Coolant Pressure Boundary Materials	All EPUs	EMCB	EMEB SRXB	5.2.3 Draft Rev. 3 April 1996	GDC-1 10 CFR 50.55a GDC-4 GDC-14 GDC-31 10 CFR Part 50, App. G	RG 1.190 GL 97-01 IN 00-17s1 BL 01-01 BL 02-01 BL 02-02 Note 2* Note 3*	2.1.4	2.1.5	2.5.3, 3.2.1, 10.7	2.5.3, 3.2.1, 10.7	4.5.2, 5.2.3
				4.5.1 Draft Rev. 3 April 1996	GDC-1 10 CFR 50.55a GDC-14						
				5.2.4 Draft Rev. 2 April 1996	10 CFR 50.55a						
				5.3.1 Draft Rev. 2 April 1996	GDC-1 10 CFR 50.55a GDC-4 GDC-14 GDC-31 10 CFR Part 50, App. G						
				5.3.3 Draft Rev. 2 April 1996							
				6.1.1 Draft Rev. 2 April 1996							
Leak-Before-Break	PWR EPUs	EMCB		3.6.3 Draft Aug. 1987	GDC-4	NUREG 1061 Vol. 3 Nov. 1984		2.1.6	N/A for BWRs		

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Protective Coating Systems (Paints) - Organic Materials	All EPUs	EMCB		6.1.2 Draft Rev. 3 April 1996	10 CFR Part 50, App. B RG 1.54		2.1.5	2.1.7	4.2.6	4.2.6	6.1.2
Effect of EPU on Flow-Accelerated Corrosion	All EPUs	EMCB				Note 4*	2.1.6	2.1.8	10.7	10.7	
Steam Generator Tube Inservice Inspection	PWR EPUs	EMCB		5.4.2.2 Draft Rev. 2 April 1996	10 CFR 50.55a	Plant TSs RG 1.121 GL 95-03 BL 88-02 GL 95-05 Note 5*		2.1.9	N/A for BWRs		
Steam Generator Blowdown System	PWR EPUs	EMCB		10.4.8 Draft Rev. 3 April 1996	GDC-14			2.1.10	N/A for BWRs		
Chemical and Volume Control System (Including Boron Recovery System)	PWR EPUs	EMCB	SPLB SRXB	9.3.4 Draft Rev. 3 April 1996	GDC-14 GDC-29			2.1.11	N/A for BWRs		
Reactor Water Cleanup System	BWR EPUs	EMCB		5.4.8 Draft Rev. 3 April 1996	GDC-14 GDC-60 GDC-61		2.1.7		3.11, 10.7	3.11	5.4.8

Notes:

1. In addition to the SRP, guidance on the neutron irradiation-related threshold for inspection for irradiation-assisted stress-corrosion cracking for BWRs is in BWRVIP-26 and for PWRs in BAW-2248 for E>1 MeV and in WCAP-14577 for E>0.1 MeV. For intergranular stress-corrosion cracking and stress-corrosion cracking in BWRs, review criteria and review guidance is contained in BWRVIP reports and associated staff safety evaluations. For thermal and neutron embrittlement of cast austenitic stainless steel, stress-corrosion cracking, and void

swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs.

2. For thermal aging of cast austenitic stainless steel, review guidance and criteria is contained in the May 19, 2000, letter from C. Grimes to D. Walters, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components."

3. For intergranular stress corrosion cracking in BWR piping, review criteria and review guidance is contained in BWRVIP reports, NUREG-0313, Revision 2, GL 88-01, Supplement 1 to GL-88-01, and associated safety evaluations.

4. Criteria and review guidance needed to review EPU applications in the area of flow-accelerated corrosion is contained in Electric Power Research Institute (EPRI) Report NSAC-202L-R2, "Recommendations for Effective an Flow-Accelerated Corrosion Program," dated April 1999. This EPRI document is copyrighted. EPRI has provided copies of this document to EMCB for use by NRC staff. Copying of this document, however, is not allowed.

5. Also see the plant-specific license amendments approving alternate repair criteria and redefining inspection boundaries.

MATRIX 2
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Mechanical and Civil Engineering

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Pipe Rupture Locations and Associated Dynamic Effects	All EPUs	EMEB		3.6.2 Draft Rev. 2 April 1996	GDC-4		2.2.1	2.2.1	10.1, 10.2	10.1, 10.2	3.6.2
Pressure-Retaining Components and Component Supports	All EPUs	EMEB		3.9.1 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-14 GDC-15		2.2.2	2.2.2	2.5.3, 3.1, 3.2.2, 3.4, 3.5, 3.7, 3.8	2.5.3, 3.1, 3.2.2, 3.4, 3.5, 3.7, 3.8	3.9.1, 3.9.2, 3.9.3, 5.2.1.1
				3.9.2 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-4 GDC-14 GDC-15	IN 95-016 IN 02-026					
				3.9.3 Draft Rev. 2 April 1996	10 CFR 50.55a GDC-1 GDC-2 GDC-4 GDC-14 GDC-15	IN 96-049 GL 96-06					
				5.2.1.1 Draft Rev. 3 April 1996	10 CFR 50.55a GDC-1	RG 1.84 RG 1.147 DG 1.1089 DG 1.1090 DG 1091					

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Reactor Pressure Vessel Internals and Core Supports	All EPUs	EMEB	[redacted]	3.9.1 Draft Rev. 3 April 1996	GDC-1 GDC-2	[redacted]	2.2.3	2.2.3	3.1, 3.3, 3.4.2	3.1, 3.3, 3.4.2	3.9.1, 3.9.2, 3.9.3 3.9.5
			[redacted]	3.9.2 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-4	IN 95-016 IN 02-026					
			[redacted]	3.9.3 Draft Rev. 2 April 1996	10 CFR 50.55a GDC-1 GDC-2 GDC-4	IN 96-049 GL 96-06					
			[redacted]	3.9.5 Draft Rev. 3 April 1996	10 CFR 50.55a GDC-1 GDC-2 GDC-4 GDC-10	IN 02-026 Note 1*					
Safety-Related Valves and Pumps	All EPUs	EMEB	[redacted]	3.9.3 Draft Rev. 2 April 1996	GDC-1 10 CFR 50.55a(f)	IN 96-049 GL 96-06	2.2.4	2.2.4	3.1, 3.8, 4.1.3, 4.1.4, 4.1.6, 4.2	3.1, 3.8, 4.1, 4.2	
			[redacted]	3.9.6 Draft Rev. 3 April 1996	GDC-1 GDC-37 GDC-40 GDC-43 GDC-46 GDC-54 10 CFR 50.55a(f)	GL 89-10 GL 95-07 GL 96-05 IN 97-090 IN 96-048s1 IN 96-048 IN 96-003 RIS 00-003 RIS 01-015 RG 1.147 RG 1.175 DG 1089 DG 1091					

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	All EPUs	EMEB	EEIB	3.10 Draft Rev. 3 April 1996	GDC-1 GDC-2 GDC-4 GDC-14 GDC-30 10 CFR Part 100, App. A 10 CFR Part 50, App. B USI A-46		2.2.5	2.2.5	10.1, 10.3.3, 3.5.1, 3.5.2	10.1, 10.3.3	3.10

Notes:

1. As indicated in IN 2002-26 and Supplement 1 to IN 2002-26, the steam dryers and other plant components recently failed at Quad Cities Units 1 and 2 during operation under extended power uprate (EPU) conditions. The failures occurred as a result of high-cycle fatigue caused by increased flow-induced vibrations at EPU conditions. The staff's review of the reactor internals as part of EPU requests will cover detailed analyses of flow-induced vibration and acoustically-induced vibration (where applicable) on reactor internal components such as steam dryers and separators, and the jet pump sensing lines that are affected by the increased steam and feedwater flow for EPU conditions. In addition, the staff is evaluating the need to address potential adverse effects on other plant components from the increased steam and feedwater flow under EPU conditions.

MATRIX 3
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Electrical Engineering

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Environmental Qualification of Electrical Equipment	All EPUs	EEIB	[redacted]	3.11 Draft Rev. 3 April 1996	10 CFR 50.49	[redacted]	2.3.1	2.3.1	10.3.1	10.3.1	3.11
Offsite Power System	All EPUs	EEIB	[redacted]	8.1 Draft Rev. 3 April 1996	GDC-17	BTP PSB-1 Draft Rev. 3 April 1996 BTP ICSB-11 Draft Rev. 3 April 1996	2.3.2	2.3.2	6.1.1 SSES NOTE S-1	6.1.1	8.2
			[redacted]	8.2 Draft Rev. 4 April 1996	GDC-17						
			[redacted]	8.2, App. A Draft Rev. 4 April 1996	GDC-17						

AC Onsite Power System	All EPUs	EEIB		8.1 Draft Rev. 3 April 1996	GDC-17		2.3.3	2.3.3	6.1.2	6.1.2	8.3
				8.3.1 Draft Rev. 3 April 1996	GDC-17						
DC Onsite Power System	All EPUs	EEIB		8.1 Draft Rev. 3 April 1996	GDC-17 10 CFR 50.63		2.3.4	2.3.4	6.2	6.2	8.3
Station Blackout	All EPUs	EEIB	SPLB SRXB	8.1 Draft Rev. 3 April 1996	10 CFR 50.63	Note 1*	2.3.5	2.3.5	9.3.2	9.3.2	15.2.6
				8.2, App. B Draft Rev. 4 April 1996	10 CFR 50.63						

1. The review of station blackout includes the effects of the EPU on systems relied upon for core cooling in the station blackout coping analysis (e.g., condensate storage tank inventory, controls and power supplies for relief valves, residual heat removing system) to ensure that the effects are accounted for in the analysis.

Susquehanna Notes:

S-1 A grid stability analysis has been performed and is provided in attachment 11. Identifies any additional evaluations or equipment modifications.

MATRIX 4
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Instrumentation and Controls

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Reactor Trip System	All EPUs	EEIB		7.2 Rev. 4 June 1997	10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-4 GDC-13 GDC-19 GDC-20 GDC-21 GDC-22 GDC-23 GDC-24		2.4.1	2.4.1	5.3, 10.4 SSES Notes S-1	5.3	7.2
Engineered Safety Features Systems	All EPUs	EEIB		7.3 Rev. 4 June 1997			2.4.1	2.4.1	5.3	5.3	7.3
Safety Shutdown Systems	All EPUs	EEIB		7.4 Rev. 4 June 1997	10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-4 GDC-13 GDC-19 GDC-24		2.4.1	2.4.1	5.3	5.3	7.4
Control Systems	All EPUs	EEIB		7.7 Rev. 4 June 1997	10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-13 GDC-19 GDC-24		2.4.1	2.4.1	5.1, 5.2, 5.3	5.1, 5.2, 5.3	7.7
Diverse I&C Systems	All EPUs	EEIB		7.8 Rev. 4 June 1997			2.4.1	2.4.1	5.1, 5.2, 5.3	5.1, 5.2, 5.3	
General guidance for use of other SRP Sections related to I&C	All EPUs	EEIB		7.0 Rev. 4 June 1997							

Susquehanna Notes:

S-1 Reactor Trip System – PPL Susquehanna LLC Letter PLA-5931, "Susquehanna Steam Electric Station Proposed License Amendment Numbers 279 for Unit 1 Operating License No. NPF-14 and 248 for Unit 2 Operating License No. NPF-22 ARTS/MELLLA Implementation," dated November 18, 2005 provides the basis for the Average Power Range Monitor (APRM) flow-biased scram and rod block trip setpoints, and the power dependent RBM setpoints. This submittal assumes prior approval of the ARTS/MELLLA License Change Request.

MATRIX 5
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Plant Systems

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Flood Protection	EPUs that result in significant increases in fluid volumes of tanks and vessels	SPLB		3.4.1 Rev. 2 July 1981	GDC-2		2.5.1.1.1	2.5.1.1.1	10.1.2, 10.2, 10.5.1	10.1, 10.2	3.4
Equipment and Floor Drainage System	EPUs that result in increases in fluid volumes or in installation of larger capacity pumps or piping systems	SPLB		9.3.3 Rev. 2 July 1981	GDC-2 GDC-4		2.5.1.1.2	2.5.1.1.2	8.1	8.1	9.3.3
Circulating Water System	EPUs that result in increases in fluid volumes associated with the circulating water system or in installation of larger capacity pumps or piping systems	SPLB		10.4.5 Rev. 2 July 1981	GDC-4		2.5.1.1.3	2.5.1.1.3	6.4.2	6.4.2	10.4.5
Internally Generated Missiles (Outside Containment)	EPUs that result in substantially higher system pressures or changes in existing system configuration	SPLB	EMCB EMEB	3.5.1.1 Rev. 2 July 1981	GDC-4		2.5.1.2.1	2.5.1.2.1	7.1, 10.1	7.1, 10.1	3.5.1.1, 3.5.1.3
Internally Generated Missiles (Inside Containment)	EPUs that result in substantially higher system pressures or changes in existing system configuration	SPLB	EMCB EMEB	3.5.1.2 Rev. 2 July 1981	GDC-4		2.5.1.2.1	2.5.1.2.1	10.1	10.1	3.5.1.2

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Turbine Generator	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.2 Rev. 2 July 1981	GDC-4		2.5.1.2.2	2.5.1.2.2	7.1	7.1	10.2
Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	EPUs that affect environmental conditions, habitability of the control room, or access to areas important to safe control of postaccident operations	SPLB	EMCB EMEB	3.6.1 Rev. 1 July 1981	GDC-4		2.5.1.3	2.5.1.3	10.1, 10.2, 8.5, 9.2	10.1, 10.2	3.6.1
Fire Protection Program	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.5.1 Rev. 3 July 1981	10 CFR 50.48 10 CFR Part 50, App. R GDC-3 GDC-5	Note 1*	2.5.1.4	2.5.1.4	6.7 SSES Note S-3	6.7	Fire Protection Review Report (FPRR)
Pressurizer Relief Tank	PWR EPUs that affect pressurizer discharge to the PRT	SPLB	EMEB	5.4.11 Rev. 2 July 1981	GDC-2 GDC-4			2.5.2	N/A to BWRs		
Fission Product Control Systems and Structures	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB	EMCB	6.5.3 Rev. 2 July 1981	GDC-41		2.5.2.1	2.5.3.1	4.5	4.5	6.5.3, 6.5.11
Main Condenser Evacuation System	EPUs for which the main condenser evacuation system is modified	SPLB		10.4.2 Rev. 2 July 1981	GDC-60 GDC-64		2.5.2.2	2.5.3.2	7.2	7.2	10.4.2
Turbine Gland Sealing System	EPUs for which the turbine gland sealing system is modified	SPLB		10.4.3 Rev. 2 July 1981	GDC-60 GDC-64		2.5.2.3	2.5.3.3	7.1	7.1	10.4.3

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Main Steam Isolation Valve Leakage Control System	BWR EPU that affect the amount of valve leakage that is assumed and resultant dose consequences.	SPLB		6.7 Rev. 2 July 1981	GDC-54		2.5.2.4		4.6	4.6	SSES Note S-1
Spent Fuel Pool Cooling and Cleanup System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB	EMCB	9.1.3 Rev. 1 July 1981	GDC-5 GDC-44 GDC-61	Note 2*	2.5.3.1	2.5.4.1	6.3	6.3	9.1.3
Station Service Water System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.2.1 Rev. 4 June 1985	GDC-4 GDC-5 GDC-44	GL 89-13 and Suppl. 1 GL 96-06 and Suppl. 1	2.5.3.2	2.5.4.2	6.4	6.4.1, 6.4.5	9.2
Reactor Auxiliary Cooling Water Systems	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.2.2 Rev. 3 June 1986	GDC-4 GDC-5 GDC-44	GL 89-13 and Suppl. 1 GL 96-06 and Suppl. 1	2.5.3.3	2.5.4.3	6.4	6.4.3	9.2
Ultimate Heat Sink	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		9.2.5 Rev. 2 July 1981	GDC-5 GDC-44		2.5.3.4	2.5.4.4	6.4.5	6.4.5	Section 9.2.7
Auxiliary Feedwater System	PWR EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.9 Rev. 2 July 1981	GDC-4 GDC-5 GDC-19 GDC-34 GDC-44			2.5.4.5	N/A for BWRs		

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Main Steam Supply System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.3 Rev. 3 April 1984	GDC-4 GDC-5 GDC-34		2.5.4.1	2.5.5.1	3.5.1	3.5.1, 3.7, 3.8, 5.3.1	5.4.5 10.3
Main Condenser	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.1 Rev. 2 July 1981	GDC-60		2.5.4.2	2.5.5.2	6.4.2, 7.2	7.2	10.4.1
Turbine Bypass System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.4 Rev. 2 July 1981	GDC-4 GDC-34		2.5.4.3	2.5.5.3	7.3	7.3	10.4.4
Condensate and Feedwater System	All EPUs except where the application demonstrates that previous analysis is bounding	SPLB		10.4.7 Rev. 3 April 1984	GDC-4 GDC-5 GDC-44		2.5.4.4	2.5.5.4	7.4	7.4	10.4.7
Gaseous Waste Management Systems	EPUs that impact the level of fission products in the reactor coolant system, or the amount of gaseous waste	SPLB	IEPB	11.3 Draft Rev. 3 April 1996	10 CFR 20.1302 GDC-3 GDC-60 GDC-61 10 CFR Part 50, App. I		2.5.5.1	2.5.6.1	8.2	8.2	11.3
Liquid Waste Management Systems	EPUs that impact the level of fission products in the reactor coolant system, or the amount of liquid waste	SPLB	IEPB	11.2 Draft Rev. 3 April 1996	10 CFR 20.1302 GDC-60 GDC-61 10 CFR Part 50, App. I		2.5.5.2	2.5.6.2	8.1	8.1	11.2

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Solid Waste Management Systems	EPUs that impact the level of fission products in the reactor coolant system, or the amount of solid waste	SPLB	IEPB	11.4 Draft Rev. 3 April 1996	10 CFR 20.1302 GDC-60 GDC-63 GDC-64 10 CFR Part 71		2.5.5.3	2.5.6.3	8.1	8.1	11.4
Emergency Diesel Engine Fuel Oil Storage and Transfer System	EPUs that result in higher EDG electrical demands	SPLB		9.5.4 Rev. 2 July 1981	GDC-4 GDC-5 GDC-17		2.5.6.1	2.5.7.1	6.1.1	6.1.1	8.3
Light Load Handling System (Related to Refueling)	EPUs except where the application demonstrates that previous analysis is bounding	SPLB	SPSB	9.1.4 Rev. 2 July 1981	GDC-61 GDC-62		2.5.6.2	2.5.7.2	6.8 SSES NOTE S-2	6.8	9.1.4

Notes:

1. Supplemental guidance for review of fire protection is provided in Attachment 1 to this matrix.

2. Supplemental guidance for review of spent fuel pool cooling is provided in Attachment 2 to this matrix.

Susquehanna Notes:

S-1 The Main Steam Isolation Valve Leakage Control System at SSES has been eliminated. The current MSIV leakage treatment method is described in a separate license amendment request that proposes a full scope implementation of an AST. Refer to PLA-5963 dated October 13, 2005.

S-2 The Fuel Handling System is not affected by the SSES CPPU.

S-3 PPL is committed to 10CFR50 Appendix R Sections IIIG, IIIJ, IIIL, and IIIO as well as Appendix A of BTP APCSB 9.5-1 as demonstrated in the FPPR.

ATTACHMENT 1 TO MATRIX 5

Supplemental Fire Protection Review Criteria

Plant Systems

This attachment provides guidance for the review of the fire protection information to be provided in an application for a power uprate. Power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's application should confirm that these elements are not impacted by the extended power uprate. This confirmation should be reflected in the staff's safety evaluation. If the licensee indicates that there is an impact on these elements, the staff should review the licensee's assessment of the impact using this attachment.

The systems relied upon to achieve and maintain safe shutdown following a fire may be affected by the power uprate due to the increase in decay heat generation following a plant trip. For fire events where the licensee is relying on one full train of the redundant systems normally used for safe shutdown, the analysis of the impact of the power uprate on the important plant process parameters performed for other plant transients (such as a loss of offsite power or a loss of main feedwater) will typically bound the impact of a fire event. In this case, a specific analysis for fire events may not be necessary. However, where licensees rely on less than full capability systems for fire events (e.g., partial automatic depressurization system capability for reduced capability makeup pump), the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the integrity of the reactor pressure vessel or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability. The staff should verify that the capability of the alternative/dedicated or backup systems relied upon for post-fire safe shutdown is sufficient to achieve and maintain safe shutdown considering the impact of the power uprate.

The plant's post-fire safe shutdown procedures may also be impacted by the power uprate. For example, the allowable time to perform necessary operator actions may decrease as a result of the power uprate. In this case, the flow rates needed for systems required to achieve and maintain safe shutdown may need to be increased. The licensee should identify the impact of the power uprate on the plant's post-fire safe shutdown procedures.

ATTACHMENT 2 TO MATRIX 5

Supplemental Spent Fuel Pool Cooling Review Criteria

Plant Systems

1. BACKGROUND

All operating nuclear power plants were licensed to certain design criteria regarding the adequacy of spent fuel pool (SFP) cooling capability. The most common criterion is that contained in General Design Criterion (GDC)-61 of Appendix A to 10 CFR Part 50. This criterion specifies, in part, that the fuel storage system (1) be designed with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal and (2) be designed to prevent a significant reduction in coolant inventory under accident conditions. Earlier licensing criteria are generally consistent with GDC-61. However, later guidance contained in Section 9.1.3 of the Standard Review Plan applied GDC-44 to the SFP cooling system. GDC-44 requires, in part, that a licensee provide a cooling system that is capable of accomplishing its safety function with or without offsite sources of power, assuming a single failure. To satisfy these criteria, each licensee should demonstrate that there is adequate SFP cooling capacity and should also demonstrate the ability to supply adequate make-up water in the event of total loss of SFP cooling.

A significant design-basis challenge to the SFP cooling system is imposed by a planned evolution (fuel transfer from the reactor vessel). Emergency offloads are not considered credible because fuel transfers may be accomplished only after plant cooldown, reactor disassembly, and refueling cavity flooding, which are time-consuming, manual processes. As a result, the staff will review factors that increase heat load (e.g., power increases, decay-time reductions, or storage capacity increases) and other operational factors that reduce heat load (e.g., longer decay times or transfer of fewer fuel assemblies to the SFP) or that increase heat removal capability (e.g., scheduling offloads for periods of reduced ultimate heat sink temperature or optimizing cooling system performance) to ensure that the licensee has demonstrated the adequacy of the SFP cooling system.

This guidance supercedes the guidance of paragraphs III.1.d. and III.1.h. of Standard Review Plan Section 9.1.3.

2. ACCEPTANCE CRITERIA

The adequacy of cooling may be evaluated against the capability to complete normal, planned activities, including fuel handling, without a degradation in safety and the ability to maintain defense-in-depth against a significant reduction in coolant inventory under accident conditions. With respect to fuel handling, which is a manual process, SFP temperatures affect safety through operating environment and visibility. At SFP temperatures below 140°F, (1) the fuel handling building ventilation is typically adequate to maintain a suitable operating environment, (2) evaporation from the SFP surface is at a sufficiently low rate to preclude fogging, and (3) the SFP temperature is within the design range of the cleanup system demineralizes to maintain water clarity. Defense-in-depth is provided by:

(1) alarms to notify operators of a loss of cooling;
(2) the capability of the SFP cooling system to maintain or reestablish, within a reasonable time, forced cooling following a single failure of an active component;
(3) the ability of the cooling system to maintain the SFP temperature below the design temperature of the SFP structure and liner following a single-active failure or a design-basis event (e.g., a seismic event) within the current design basis of the facility; and
(4) the availability of two reliable sources of makeup water, one having sufficient capacity to make up for evaporation following a total loss of forced cooling. Only one source need have this capacity because the heat load and boil-off rate decrease rapidly with time from the peak value such that a much lower makeup rate would be effective in extending the recovery time.

The reliability of the systems relied upon to meet these guidelines should be maintained consistent with the plant's current design basis.

3. REVIEW PROCEDURES

3.1. Adequate SFP Cooling Capacity

The licensee demonstrates adequate SFP cooling capacity by either performing a bounding evaluation or committing to a method of performing outage-specific evaluations.

3.1.1. Bounding Calculation

Two scenarios are analyzed: (1) full cooling capability and (2) a single failure of an active cooling system component.

3.1.1.1. Full Cooling System Capability Evaluation

Analysis conditions:

(1) decay heat load is calculated based on bounding estimates of offload size, decay time, power history, and inventory of previously discharged assemblies
(2) heat removal capability is based on bounding estimates of ultimate heat sink temperature, cooling system flow rates, and heat exchanger performance (e.g., fouling and tube plugging margin)
(3) alternate heat removal paths (e.g., evaporative cooling) should be appropriately validated and based on bounding input parameter values (e.g., air temperature, relative humidity, and ventilation flow rate)
(4) actual bulk SFP temperature should remain below 140 °F - calculated SFP temperatures up to approximately 150 °F are acceptable when justified by conservative methods or assumptions
(5) with appropriate administrative controls to verify that analysis inputs bound actual conditions, a set of bounding analyses may be prepared by the licensee to support operational flexibility.

3.1.1.2. Single-Active Failure Evaluation

Analysis conditions:

(1) decay heat load is calculated based on a bounding estimate of offload size, decay time, power history, and inventory of previously discharged assemblies
(2) heat removal capability is based on a bounding estimate of ultimate heat sink temperature, heat exchanger performance (e.g., fouling and tube plugging margin), and cooling system flow rates assuming the limiting single failure with regard to heat removal capability
(3) alternate heat removal paths (e.g., evaporative cooling) should be appropriately validated and based on bounding input parameter values (e.g., air temperature, relative humidity, and ventilation flow rate)
(4) calculated bulk SFP temperature should remain below the design temperature of the SFP structure and liner, and calculated peak storage cell temperature should remain below the storage rack design temperature
(5) for plants where a single failure results in a complete loss of forced cooling, the licensee's analysis should demonstrate that the loss of cooling would be identified and forced cooling would be restored before the bounding decay heat load would cause the SFP temperature to reach its design limit
(6) with appropriate administrative controls to verify that analysis inputs bound actual conditions, a set of bounding analyses may be prepared by the licensee to support operational flexibility.

3.1.2. Cycle-Specific Calculation:

The licensee can choose to define a method to calculate operational limits prior to every offload using the anticipated actual conditions at the time of the offload.

Cycle-specific analysis conditions:

(1) define the method to calculate decay heat load based on decay time, power history, and inventory of previous fuel discharges
(2) define the method to calculate cooling system heat removal capacity based on ultimate heat sink temperature, cooling system flow rates, and heat exchanger performance parameters
(3) define the method for calculating alternate heat removal capability (e.g., evaporative cooling) and provide validation of the method
(4) using the methods defined to calculate heat load and heat removal capability, define the method to determine the limiting value of the variable operational parameter (typically, decay time) such that bulk SFP temperature will remain below 140 °F with full cooling capability
(5) using the methods defined to calculate heat load and heat removal capability, define the method to determine the limiting value of the variable operational parameter (typically, decay time) such that bulk SFP temperature will be maintained below the SFP structure design temperature assuming a single failure affecting the forced cooling system (this may be a heat-balance analysis if cooling is degraded or a heatup-rate analysis if forced cooling is completely lost and subsequently recovered using redundant components)
(6) describe administrative controls that will be implemented each offload to ensure the

cycle-specific analysis inputs and results bound actual conditions prior to fuel movement

3.2. Adequate Make-Up Supply

(1) Following a loss-of-SFP cooling event, the licensee should be able to provide two sources of make-up water prior to the occurrence of boiling in the pool. To determine the time to boil, the initial pool temperature is the peak temperature from a planned offload, assuming the worst single-active failure occurred.

(2) At least one make-up source should have a capacity that is equal to or greater than the calculated boil-off rate so that the SFP level can be maintained. Only one source need have this capacity because the heat load and boil-off rate decrease rapidly with time from the peak value such that a much lower makeup rate would be effective in extending the recovery time.

MATRIX 6
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Containment Review Considerations

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
PWR Dry Containments, Including Subatmospheric Containments	EPUs for PWR plants with dry containments (including subatmospheric containments) except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.1.A Rev. 2 July 1981	GDC-13 GDC-16 GDC-38 GDC-50 GDC-64			2.6.1	N/A for BWRs		
Ice Condenser Containments	EPUs for PWR plants with ice condenser containments except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.1.B Rev. 2 July 1981	GDC-13 GDC-16 GDC-38 GDC-50 GDC-64			2.6.1	N/A for BWRs		
Pressure-Suppression Type BWR Containments	EPUs for BWR plants with pressure-suppression containments except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.1.C Rev. 6 Aug. 1984	GDC-4 GDC-13 GDC-16 GDC-50 GDC-64		2.6.1		4.1 through 4.1.3, 9.3.2, 10.3.1	4.1	6.2.1
Subcompartment Analysis	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.2 Rev. 2 July 1981	GDC-4 GDC-50		2.6.2	2.6.2	4.1.2.3	4.1	6.2.1.2

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB SPSB		6.2.1 Rev. 2 July 1981 6.2.1.3 Rev. 1 July 1981	GDC-50 10 CFR Part 50, App. K		2.6.3.1	2.6.3.1	4.1.1 through 4.1.2.2	4.1, 10.1	6.2.1.3
Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures	PWR EPUs except where the application demonstrates that previous analysis is bounding	SPSB		6.2.1 Rev. 2 July 1981 6.2.1.4 Rev. 1 July 1981	GDC-50			2.6.3.2	N/A for BWRs		
Combustible Gas Control In Containment	EPUs that impact hydrogen release assumptions	SPSB		6.2.5 Rev. 2 July 1981	10 CFR 50.44 10 CFR 50.46 GDC-5 GDC-41 GDC-42 GDC-43		2.6.4	2.6.4	4.7	4.7	6.2.5
Containment Heat Removal		SPSB		6.2.2 Rev. 4 Oct. 1985	GDC-38	DG-1107	2.6.5	2.6.5	3.10, 4.2.6	3.10, 4.2.6	
Secondary Containment Functional Design	EPUs that affect the pressure and temperature response, or draw-down time of the secondary containment	SPSB		6.2.3 Rev. 2 July 1981	GDC-4 GDC-16		2.6.6		4.5	4.5	6.2.3

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Capability Studies	PWR EPUs except where the application demonstrates that previous analysis is bounding	SPSB	SRXB	6.2.1 Rev. 2 July 1981	10 CFR 50.46 10 CFR Part 50, App. K			2.6.6	N/A for BWRs		
				6.2.1.5 Rev. 2 July 1981							

MATRIX 7
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Habitability, Filtration, and Ventilation

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Control Room Habitability System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	6.4 Draft Rev. 3 April 1996	GDC-4 GDC-19	Note 1* Note 2*	2.7.1	2.7.1	4.4	4.4	6.4
ESF Atmosphere Cleanup System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	6.5.1 Rev. 2 July 1981	GDC-19 GDC-41 GDC-61 GDC-64	[redacted]	2.7.2	2.7.2	4.5	4.5	6.5.1
Control Room Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	9.4.1 Rev. 2 July 1981	GDC-4 GDC-19 GDC-60	[redacted]	2.7.3	2.7.3	4.4	4.4, 6.6	9.4.1
Spent Fuel Pool Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	9.4.2 Rev. 2 July 1981	GDC-60 GDC-61	[redacted]	2.7.4	2.7.4	6.6	6.6	9.4.2, 9.4.6
Auxiliary and Radwaste Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	9.4.3 Rev. 2 July 1981	GDC-60	[redacted]	2.7.5	2.7.5	6.6	6.6	9.4.3
Turbine Area Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB	[redacted]	9.4.4 Rev. 2 July 1981	GDC-60	[redacted]	2.7.5	2.7.5	6.6	6.6	9.4.4

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
ESF Ventilation System	All EPUs except where the application demonstrates that previous analysis is bounding	SPSB		9.4.5 Rev. 2 July 1981	GDC-4 GDC-17 GDC-60		2.7.6	2.7.6	6.6 ADD SSES NOTE?	6.6	9.4.2, 9.4.5, 9.4.7, 9.4.8

Notes:

1. Under SRP Section 6.4, Section II, "Acceptance Criteria," the discussion for Item C related to GDC-19 should be supplemented with "and providing a suitably controlled environment for the control room operators and the equipment located therein."

2. Under SRP Section 6.4, Section II, Item 2, "Ventilation System Criteria," the discussion related to review of the control room area ventilation system under SRP Section 9.4.1 should be retained.

MATRIX 8
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Reactor Systems

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Fuel System Design	All EPUs	SRXB		4.2 Draft Rev. 3 April 1996	10 CFR 50.46 GDC-10 GDC-27 GDC-35	Note 1* Note 2*	2.8.1	2.8.1	2.1, 2.2, 2.3, 2.5, 4.3, 9.1		4.2
Nuclear Design	All EPUs	SRXB		4.3 Draft Rev. 3 April 1996	GDC-10 GDC-11 GDC-12 GDC-13 GDC-20 GDC-25 GDC-26 GDC-27 GDC-28	RG 1.190 GSI 170 IN 97-085	2.8.2	2.8.2	2.1, 2.2, 2.3, 2.4, 2.5, 4.3, Section 5 9.1, 9.2, 9.3		4.3
Thermal and Hydraulic Design	All EPUs	SRXB		4.4 Draft Rev. 2 April 1996	GDC-10 GDC-12	Note 3*	2.8.3	2.8.3	2.2, 2.3, 2.4, 5.3, 9.1		4.4
Functional Design of Control Rod Drive System	All EPUs	SRXB	SPLB	4.6 Draft Rev. 2 April 1996	GDC-4 GDC-23 GDC-25 GDC-26 GDC-27 GDC-28 GDC-29 10 CFR 50.62(c)(3)		2.8.4.1	2.8.4.1	2.5	2.5	4.6

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Overpressure Protection during Power Operation	All EPUs	SRXB		5.2.2 Draft Rev. 3 April 1996	GDC-15 GDC-31	Note 4*	2.8.4.2	2.8.4.2	3.1		5.2.2
Overpressure Protection during Low Temperature Operation	PWR EPUs	SRXB		5.2.2 Draft Rev. 3 April 1996	GDC-15 GDC-31			2.8.4.3	N/A for BWRs		
Reactor Core Isolation Cooling System	BWR EPUs	SRXB		5.4.6 Draft Rev. 4 April 1996	GDC-4 GDC-5 GDC-29 GDC-33 GDC-34 GDC-54 10 CFR 50.63		2.8.4.3		3.9 9.1.3 9.3.2	3.9	5.4.6
Residual Heat Removal System	All EPUs	SRXB		5.4.7 Draft Rev. 4 April 1996	GDC-4 GDC-5 GDC-19 GDC-34	Note 5*	2.8.4.4	2.8.4.4	3.10, 4.2.4, 4.2.6, 6.3	3.10	5.4.7
Emergency Core Cooling System	All EPUs	SRXB		6.3 Draft Rev. 3 April 1996	GDC-4 GDC-27 GDC-35 10 CFR 50.46 10 CFR Part 50, App. K	Note 6*	2.8.5.6.2	2.8.5.6.3	4.2, 4.3		6.3
Standby Liquid Control System	BWR EPUs	SRXB	EMCB SPLB	9.3.5 Draft Rev. 3 April 1996	GDC-26 GDC-27 10 CFR 50.62(c)(4)	Note 10*	2.8.4.5		6.5, 9.3.1	6.5	9.3.5

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	All EPUs	SRXB	[redacted]	15.1.1-4 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-20 GDC-26	Note 7*	2.8.5.1	2.8.5.1.1	9.1		15.1.1-4
Loss of External Load; Turbine Trip, Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve (BWR); and Steam Pressure Regulator Failure (Closed)	All EPUs	SRXB	[redacted]	15.2.1-5 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.2.1	2.8.5.2.1	3.1, 3.8, 9.1		15.2.1-5
Loss of Nonemergency AC Power to the Station Auxiliaries	All EPUs	SRXB	[redacted]	15.2.6 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.2.2	2.8.5.2.2	6.1, 9.1		15.2.6
Loss of Normal Feedwater Flow	All EPUs	SRXB	EEIB	15.2.7 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.2.3	2.8.5.2.3	3.9, 9.1		15.2.7
Feedwater System Pipe Breaks Inside and Outside Containment	PWR EPUs	SRXB	EEIB	15.2.8 Draft Rev. 2 April 1996	GDC-27 GDC-28 GDC-31 GDC-35	Note 7*	[redacted]	2.8.5.2.4	N/A for BWRs		
Loss of Forced Reactor Coolant Flow Including Trip of Pump Motor and Flow Controller Malfunctions	All EPUs	SRXB	[redacted]	15.3.1-2 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.3.1	2.8.5.3.1	9.1		15.3.1-2

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	All EPUs	SRXB		15.3.3-4 Draft Rev. 3 April 1996	GDC-27 GDC-28 GDC-31	Note 7*	2.8.5.3.2	2.8.5.3.2	9.1, 9.2		15.3.3-4 SSES NOTE S-1
Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition	All EPUs	SRXB		15.4.1 Draft Rev. 3 April 1996	GDC-10 GDC-20 GDC-25	Note 7*	2.8.5.4.1	2.8.5.4.1	5.1.2, 5.3.4		15.4.1 SSES NOTE S-2
Uncontrolled Control Rod Assembly Withdrawal at Power	All EPUs	SRXB		15.4.2 Draft Rev. 3 April 1996	GDC-10 GDC-20 GDC-25	Note 7*	2.8.5.4.2	2.8.5.4.2	5.3.5, 9.1		15.4.2
Control Rod Misoperation (System Malfunction or Operator Error)	PWR EPUs	SRXB		15.4.3 Draft Rev. 3 April 1996	GDC-10 GDC-20 GDC-25	Note 7*		2.8.5.4.3	N/A for BWRs		
Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate	All EPUs	SRXB		15.4.4-5 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-20 GDC-26 GDC-28	Note 7*	2.8.5.4.3	2.8.5.4.4	9.1		15.4.4-5
Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	PWR EPUs	SRXB		15.4.6 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*		2.8.5.4.5	N/A for BWRs		

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Spectrum of Rod Ejection Accidents	PWR EPUs	SRXB		15.4.8 Draft Rev. 3 April 1996	GDC-28	Note 7*		2.8.5.4.6	N/A for BWRs		
Spectrum of Rod Drop Accidents	BWR EPUs	SRXB		15.4.9 Draft Rev. 3 April 1996	GDC-28	Note 7*	2.8.5.4.4		5.3, 9.2		15.4.9
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	All EPUs	SRXB		15.5.1-2 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7* Note 8*	2.8.5.5	2.8.5.5	9.1		15.5.1-2
Inadvertent Opening of a PWR Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve	All EPUs	SRXB		15.6.1 Draft Rev. 2 April 1996	GDC-10 GDC-15 GDC-26	Note 7*	2.8.5.6.1	2.8.5.6.1	9.1		15.6.1, 15.1.4 SSES NOTE S-3
Steam Generator Tube Rupture	PWR EPUs	SRXB		15.6.3 Draft Rev. 3 April 1996	Note 7*	Note 7*		2.8.5.6.2	N/A for BWRs		
Loss-of Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	All EPUs	SRXB		15.6.5 Draft Rev. 3 April 1996	GDC-35 10 CFR 50.46	Note 7* Note 9*	2.8.5.6.2	2.8.5.6.3	4.3		15.6.5
Anticipated Transient Without Scram	All EPUs	SRXB				Note 7* Note 10*	2.8.5.7	2.8.5.7	6.5, 9.3.1, 9.3.3	9.3	15.8

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
New Fuel Storage	EPU applications that request approval for new fuel design.	SRXB		9.1.1 Draft Rev. 3 April 1996	GDC-62		2.8.6.1	2.8.6.1	N/A for SSES SSES NOTE S-4		
Spent Fuel Storage	EPU applications that request approval for new fuel design.	SRXB		9.1.2 Draft Rev. 4 April 1996	GDC-4 GDC-62		2.8.6.2	2.8.6.2	N/A for SSES SSES NOTE S-4		

Notes:

1. When mixed cores (i.e., fuels of different designs) are used, the review covers the licensee's evaluation of the effects of mixed cores on design-basis accident and transient analyses.

2. The current acceptance criteria for fuel damage for reactivity insertion accidents (RIAs) need revision per Research Information Letter No. 174, "Interim Assessment of Criteria for Analyzing Reactivity Accidents at High Burnup." The Office of Nuclear Regulatory Research is conducting confirmatory research on RIAs and the Office of Nuclear Reactor Regulation is discussing the issue of fuel damage criteria with the nuclear power industry as part of the industry's proposal to increase future fuel burnup limits. In the interim, current methods for assessing fuel damage in RIAs are considered acceptable based on the NRC staff's understanding of actual fuel performance, as shown in three-dimensional kinetic calculations which indicate acceptably low fuel cladding enthalpy.

3. The review also covers core design changes and any effects on radial and bundle power distribution, including any changes in critical heat flux ratio and critical power ratio. The review will also confirm the adequacy of the flow-based average power range monitor flux trip and safety limit minimum critical power ratio at the uprated conditions.

4. The review also covers the determination of allowable power levels with inoperable main steam safety valves.

5. The review also covers the total time necessary to reach the shutdown cooling initiation temperature.

6. The review for BWRs will cover the justification for changes in calculated peak cladding temperature (PCT) for the design-basis case and the upper-bound case and any impact of the changes in PCTs on the use of the design methods for the power uprate.

7. The review:
   - confirms that the licensee used NRC-approved codes and methods for the plant-specific application and the licensee's use of the codes and methods complies with any limitations, restrictions, and conditions specified in the approving safety evaluation.
   - confirms that all changes of reactor protection system trip delays are correctly addressed and accounted for in the analyses.
   - (for PWRs) confirms that steam generator plugging and asymmetry limits are accounted for in the analyses.
   - (for PWRs) covers the licensee's evaluation of the effects of Westinghouse Nuclear Service Advisory Letters (NSALs), NSAL 02-3 and Revision 1, NSAL 02-4, and NSAL 02-5. These NSALs document problems with water level setpoint uncertainties in Westinghouse-designed steam generators. The review is conducted to ensure that the effects of the identified problems have been accounted for in steam generator water level setpoints used in LOCA, non-LOCA, and ATWS analyses.
8. For the inadvertent operation of emergency core cooling system and chemical and volume control system malfunctions that increase reactor coolant inventory events: (a) non-safety-grade pressure-operated relief valves should not be credited for event mitigation and (b) pressurizer level should not be allowed to reach a pressurizer water-solid condition.

9. The review also verifies that:
   - Licensee and vendor processes ensure LOCA analysis input values for PCT-sensitive parameters bound the as-operated plant values for those parameters
   - (For PWRs) The models and procedures continue to comply with 10 CFR 50.46 during the switchover from the refueling water storage tank to the containment sump (i.e., the core remains adequately cool during any flow reduction or interruption that may occur during switchover).
   - (For PWRs) Large-break LOCA analyses account for boric acid buildup during long-term core cooling and that the predicted time to initiate hot leg injection is consistent with the times in the operating procedures.
   - (For BWRs) The licensee's comparison of parameters used in the LOCA analysis with actual core design parameters provide the needed justification to confirm the applicability of the generic LOCA methodology.

10. The ATWS review is conducted to ensure that the plant meets the 10 CFR 50.62 requirements:

    - For PWR plants with both a diverse scram system (DSS) and ATWS mitigation system actuation circuitry (AMSAC), the staff will not review ATWS for EPUs.

- For PWR plants where a DSS is not specifically required by 10 CFR 50.62, a review is conducted to verify that the consequences of an ATWS are acceptable. The acceptance criteria is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient and the primary system relief capacity.
- For BWR plants, the review is conducted to ensure that the licensee has appropriately accounted for changes in analyses due to the uprated power level and confirm that required equipment, such as the standby liquid control system (SLCS) pumps, can deliver required flowrates. The review will also cover the SLCS relief valve margin. In addition, a review is conducted to ensure that SLCS flow can be injected at the assumed time without lifting bypass relief valves during the limiting ATWS.

Susquehanna Notes:

S-1 Pump Seizure / Shaft Break: FSAR Section 15.3.4 concludes that the pump seizure accident is more limiting than the pump shaft break. Section 15.3.3 of the FSAR (Pump Seizure) will be updated to be consistent with the conclusions in the PUSAR.

S-2 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition: Continuous rod withdrawal during a reactor startup from a subcritical or low power startup condition is described in SSES FSAR Section 15.4.1.2. As described in the FSAR, the low power rod withdrawal error events are considered as non-limiting events, and are not reanalyzed as part of the reload analysis unless the event disposition changes.

The original FSAR analysis of the transient caused by continuous control rod withdrawal in the startup range demonstrates considerable margin for the peak fuel enthalpy to the licensing basis criterion of 170 cal/gm.

S-3 Inadvertent Opening of a BWR Pressure Relief Valve: Section 15.1.4 of the SSES FSAR identifies this event as non-limiting based on a qualitative analysis. Since dome pressure is unchanged at EPU conditions the SRV capacity per valve remains the same which means there is a minimal effect on the depressurization for this event at EPU conditions. Therefore, the original qualitative analysis conclusions remain valid for the transition to EPU conditions.

S-4 The SSES EPU submittal does not request approval for a new fuel design.

MATRIX 9
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Source Terms and Radiological Consequences Analyses

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Source Terms for Input into Radwaste Management Systems Analyses	All EPUs	SPSB		11.1 Draft Rev. 3 April 1996	10 CFR Part 20 10 CFR Part 50, App. I GDC-60		2.9.1	2.9.1	8.4, 8.6	8.4, 8.6	11.1, 11.2, 11.3, 11.4
Radiological Consequence Analyses Using Alternative Source Terms	EPUs that utilize alternative source term	SPSB	EEIB EMCB EMEB IEPB SPLB SRXB	15.0.1 Rev. 0 July 2000	10 CFR 50.67 GDC-19 10 CFR 50.49 10 CFR Part 51 10 CFR Part 50, App. E NUREG-0737		2.9.2	2.9.2	8.5 9.2 SSES NOTE S-1	8.5, 9.2	2.3.6.4, 15.2, 15.3, 15.4, 15.6, 15.7, 18.1 Appendix 15B, 15C, 15D
Radiological Consequences of Main Steamline Failures Outside Containment for a PWR	PWR EPUs that do not utilize alternative source term whose main steamline break analyses result in fuel failure	SPSB	SRXB	15.1.5, App. A Draft Rev. 3 April 1996	10 CFR Part 100	Notes 4, 5, 6, 7, 27*		2.9.2	N/A for BWRs		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	EPUs that do not utilize alternative source term whose reactor coolant pump rotor seizure or reactor coolant pump shaft break results in fuel failure	SPSB	SRXB	15.3.3-4 Draft Rev. 3 April 1996	10 CFR Part 100	Notes 5, 8, 9, 27*		2.9.3	N/A for SSES		

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Radiological Consequences of a Control Rod Ejection Accident	PWR EPUs that do not utilize alternative source term whose rod ejection accident results in fuel failure or melting	SPSB	SRXB	15.4.8, App. A Draft Rev. 2 April 1996	10 CFR Part 100	Notes 4, 21, 22, 27*		2.9.4	N/A for BWRs		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of Control Rod Drop Accident	BWR EPUs that do not utilize alternative source term whose control rod drop accident results in fuel failure or melting	SPSB	SRXB	15.4.9, App. A Draft Rev. 3 April 1996	10 CFR Part 100	Notes 9, 10, 27*	Notes 1, 2, 3, 28, 29*		N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19						
Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment	EPUs that do not utilize alternative source term whose failure of small lines carrying primary coolant outside containment result in fuel failure	SPSB		15.6.2 Draft Rev. 3 April 1996	GDC-55 10 CFR Part 100		2.9.3	2.9.5	N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of Steam Generator Tube Failure	PWR EPUs that do not utilize alternative source term whose steam generator tube failure results in fuel failure	SPSB	SRXB	15.6.3 Draft Rev. 3 April 1996	10 CFR Part 100	Notes 4, 13, 14, 15, 27*		2.9.6	N/A for BWRs		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Radiological Consequences of Main Steamline Failure Outside Containment for a BWR	BWR EPUs that do not utilize alternative source term whose main steam line failure outside containment results in fuel failure	SPSB	SRXB	15.6.4 Draft Rev. 3 April 1996	10 CFR Part 100	Note 27*	2.9.4		N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of a Design Basis Loss-Of-Coolant-Accident Including Containment Leakage Contribution	EPUs that do not utilize alternative source term	SPSB	SPLB	15.6.5, App. A Draft Rev. 2 April 1996	10 CFR Part 100	Notes 4, 23, 24, 25, 26, 27*	2.9.5	2.9.7	N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of a Design Basis Loss-Of-Coolant-Accident: Leakage from ESF Components Outside Containment	EPUs that do not utilize alternative source term	SPSB	SPLB	15.6.5, App. B Draft Rev. 2 April 1996	10 CFR Part 100	Notes 11, 27*	2.9.5	2.9.7	N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of a Design Basis Loss-Of-Coolant-Accident: Leakage from Main Steam Isolation Valves	BWR EPUs that do not utilize alternative source term	SPSB		15.6.5, App. D Draft Rev. 2 April 1996	10 CFR Part 100	Notes 9, 12, 27*	2.9.5		N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Radiological Consequences of Fuel Handling Accidents	EPUs that do not utilize alternative source term	SPSB	SPLB	15.7.4 Draft Rev. 2 April 1996	10 CFR Part 100 GDC-61	Notes 4, 5, 18, 19, 20, 27*	2.9.6	2.9.8	N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					
Radiological Consequences of Spent Fuel Cask Drop Accidents	EPUs that do not utilize alternative source term	SPSB	EMEB SPLB	15.7.5 Draft Rev. 3 April 1996	10 CFR Part 100 GDC-61	Notes, 5, 16, 17, 8, 18, 27*	2.9.7	2.9.9	N/A for SSES		
				6.4 Draft Rev. 3 April 1996	GDC-19	Notes 1, 2, 3, 28, 29*					

Notes:

1. In addition to SRP Section 15.6.5, Appendices A, B, and D, dose consequences in the control room are determined from design-basis accidents as part of the review for SRP Sections 15.0.1; 15.1.5, Appendix A; 15.3.3-4, 15.4.8, Appendix A; 15.4.9, Appendix A; 15.6.2, 15.6.3, 15.6.4, 15.7.4, and 15.7.5.

2. Regulatory Guide 1.95 was canceled. Relevant guidance from Regulatory Guide 1.95 was incorporated into Regulatory Guide 1.78, Revision 1 in January 2002. Therefore, Regulatory Guide 1.95 should not be used.

3. Table 6.4-1, attached to SRP Section 6.4 and referred to in Item 7, "Independent Analyses," of the "Review Procedures" Section of SRP Section 6.4 may not be used.

4. Acceptable dose conversion factors may be taken from Table 2.1 of Federal Guidance Report 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," Environmental Protection Agency, 1988; and Table III.1 of Federal Guidance Report 12, " External Exposure to Radionuclides in Air, Water, and Soil," Environmental Protection Agency, 1993.

5. NUREG-1465 should not be used.

6. For the review of the main steamline failure accident, review of facilities licensed with, or applying for, alternative repair criteria (ARC) should use SRP Section 15.1.5, Appendix A, in conjunction with the guidance in Draft Regulatory Guide DG-1074, "Steam Generator Tube Integrity," December 1998, for acceptable assumptions and methodologies for performing radiological analyses.

7. For facilities that implement ARC, the primary-to-secondary leak rate in the faulted generator should be assumed to be the maximum accident-induced leakage derived from the repair criteria and burst correlations. The leak rate limiting condition for operation specified in the technical specifications is equally apportioned among the unaffected steam generators.

8. Guidance for the radiological consequences analyses review with respect to acceptable modeling of the radioactivity transport is given in SRP Section 15.6.3, "Radiological Consequences of Steam Generator Tube Failure (PWR)," for applicants that use the traditional source term, based on TID-14844.

9. References to specific computer codes (e.g., SARA, TACT, Pipe Model) are not necessary since other computer codes/methods may be used.

10. In the second paragraph of Section III, "Review Procedure," it is stated that the control rod drop accident is expected to result in radiological consequences less than 10 percent of the 10 CFR Part 100 guideline values, even with conservative assumptions. The value of 10 percent should be replaced with 25 percent.

11. In Section III, "Review Procedures," the guidance in the fourth paragraph, which deals with passive failures, should not be used.

12. The last paragraph on page 15.6.5-4 refers to a "code" developed by J. E. Cline and Associates, Inc. This is identified as Reference 5 in the paragraph. The word "code" should be changed to "model" because the staff does not have the computer code. In addition, the correct reference to the work by J. E. Cline and Associates, Inc., is 4.

13. Item 4 of the "Review Interfaces" section should be deleted. SPSB review of the steam generator tube rupture accidents for their contribution to plant risk is not currently used in the design-basis accident review for radiological consequences.

14. The reference to Figure 3.4-1 of the Nuclear Steam Supply System vendor Standard Technical Specification in Item 6.(a) of Section III, "Review Procedures," does not apply. In addition, the primary coolant iodine concentration discussed in this Item is the 48-hour maximum value.
15. In Item 6.(b) of Section III, "Review Procedures," the multiplier of 500 used for estimating the increase in iodine release rate is reduced to 335 as a result of the staff's review of iodine release rate data collected by Adams and Atwood.

16. The reference to SRP Section 9.1.4 in Item 2.c of the "Review Interfaces" section should be changed to SRP Section 9.1.5.

17. The reference to Regulatory Guide 1.25, which was deleted in 1996, should be retained, with exceptions as noted below in Note 18.

18. The following exceptions to Regulatory Guide 1.25 are provided. These exceptions are based on the staff's review of NUREG/CR-6703.

The fraction of the core inventory assumed to be in the gap for the various nuclides are given in the table below. The release fractions from the table are used in conjunction with the calculated fission product inventory and the maximum core radial peaking factor. These release fractions have been determined to be acceptable for use with currently approved LWR fuel with a peak burnup up to 62,000 MWD/MTU, provided that the maximum linear heat generation rate will not exceed 6.3 kW/ft peak rod average power for rods with burnups that exceed 54 GWD/MTU. As an alternative, fission gas release calculations using NRC-approved methodologies may be considered on a case-by-case basis.

NON-LOCA FRACTION OF FISSION PRODUCT INVENTORY IN GAP	
GROUP	**FRACTION**
I-131	0.08
Kr-85	0.10
Other Noble Gases	0.05
Other Iodines	0.05

19. References to the Standard Technical Specifications should be replaced with references to the plant-specific technical specifications or technical requirements manual (TRM).

20. Technical Specification Task Force (TSTF) Traveler TSTF-51 proposed to add the term "recently," as it applies to irradiated fuel, to the applicability section of certain technical specifications. The proposed change is intended to remove certain technical specifications requirements for operability of ESF systems (e.g., secondary containment isolation and filtration systems) during refueling. The associated technical specifications bases define "recently," as it applies to irradiated fuel, as the minimum decay time used in supporting radiological consequences analyses of fuel handling accidents. Radiological consequences analyses for these applicants should generally assume a 2-hour release directly to the environment, without holdup or mitigation by ESF systems and no credit for containment closure. Additionally, licensees adding the term "recently" must make a commitment for a single normal or contingency method to promptly close primary or secondary containment penetrations. Such prompt methods need not completely block the penetration or be capable of resisting pressure. The review of this commitment and the prompt methods should be coordinated with IORB, SPLB, and IEPB.

21. In the last sentence of Item 2 of the "Review Interfaces" section, the reference to the number of fuel pins experiencing departure from nucleate boiling (DNB) should be deleted. The reference to fuel clad melting should be used and is therefore retained.

22. In Item 2 of the "Review Procedures" section, the references to the "number of fuel pins reaching DNB" should be deleted and replaced with "the number of fuel pins with cladding failure." In addition, the use of a conservative value of 10 percent for fuel cladding failure in the calculation of the radiological consequences of the rod ejection accident is acceptable.

23. In Item 1 of the "Areas of Review" section, the use of the word "established" is incorrect. The word "established" should be replaced with the word "assessed."

24. In Item 1 of the "Acceptance Criteria" section, the following text in the last line should be deleted: "3.0 Sv (300 rem) to the thyroid and 0.25 Sv (25 rem) to the whole body."

25. In Item 1 of the "Review Procedures" section, the following should be added after the first sentence:

Appendix K to 10 CFR Part 50 defines conservative analysis assumptions for evaluation of ECCS performance during design-basis LOCAs. Appendix K requires the licensees to assume that the reactor has been operating continuously at a power level at least 1.02 times the licensed power level to allow for instrumentation error. Appendix K allows for an assumed power level less than 1.02 times the licensed power level but not less than the licensed power level, provided the alternative value has been demonstrated to account for uncertainties due to power level instrumentation error.

26. In Item 2 of the "Review Procedures" section, the following statements should be deleted:

"A check is made of the LOCA [loss-of-coolant accident] assumptions listed in Chapter 15 of the SAR to verify that the primary containment leakage rate has been assumed to remain constant over the course of the accident for a BWR and to remain constant at one half of the initial leak rate after 24 hours for a PWR."

"The leakage rate used should correspond to that given in the technical specification."

The above statements should be replaced with the following:

"A check is made of the LOCA assumptions listed in Chapter 15 of the SAR to verify acceptable primary containment leakage assumptions. The primary containment should be assumed to leak at the peak pressure technical specification leak rate for the first 24 hours. For PWRs, the leakage rate may be reduced after the first 24 hours to 50 percent of the TS leak rate. For BWRs, leakage may be reduced after the first 24 hours, if supported by plant configuration and analyses, to a value not less than 50 percent of the TS leak rate. Leakage from subatmospheric containments is assumed to terminate when the containment is brought to and maintained at a subatmospheric condition, as defined by the TSs."

27. The staff has drafted updated guidance on performing design-basis radiological analyses in draft Regulatory Guide DG-1113, "Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors," issued for public comment January 2002. The resulting final regulatory guide may be used for guidance on review of design-basis accident non-alternative source term radiological analyses after the date of issuance of the final regulatory guide.

28. In Section II, "Acceptance Criteria," the discussion for Item C related to GDC-19 should be supplemented with

"and providing a suitably controlled environment for the control room operators and the equipment located therein."

29. In Section II, Item 2, "Ventilation System Criteria," the discussion related to review of the control room area ventilation system under SRP Section 9.4.1 should be retained.

Susquehanna Notes – Matrix 9:

S-1 The radiological consequence analyses using the Alternate Source Term (AST) have been previously evaluated for SSES EPU conditions in a separate License Amendment Request PLA-5963 dated October 13, 2005. This submittal proposed a full-scope implementation of an AST, which complies with the guidance given in R.G. 1.183 and SRP 15.01.

MATRIX 10
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Health Physics

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Radiation Sources	All EPUs	IEPB		12.2 Draft Rev. 3 April 1996	10 CFR Part 20		2.10.1	2.10.1	8.3, 8.4	8.3, 8.4	12.2
Radiation Protection Design Features	All EPUs	IEPB		12.3-4 Draft Rev. 3 April 1996	10 CFR Part 20 GDC-19	Note 1*	2.10.1	2.10.1	8.5, 8.6	8.5, 8.6	12.3, 12.4
Operational Radiation Protection Program	All EPUs	IEPB		12.5 Draft Rev. 3 April 1996	10 CFR Part 20	Note 2* Note 3*	2.10.1	2.10.1	8.5	8.5	12.5

Notes:

1. Regulatory Guide 8.12, "Criticality Accident Alarm Systems" has been withdrawn and should not be used.
2. Regulatory Guide 8.3, "Film Badge Performance Criteria" has been withdrawn and should not be used.
3. Regulatory Guide 8.14, "Personnel Neutron Dosimeters" has been withdrawn and should not be used.

MATRIX 11
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Human Performance

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Reactor Operator Training	All EPUs	IROB		13.2.1* Draft Rev. 2 Dec. 2002	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6	10.6	13.2.1
Training for Non-Licensed Plant Staff	All EPUs	IROB		13.2.2* Draft Rev. 2 Dec. 2002	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6	10.6	13.2.1
Operating and Emergency Operating Procedures	All EPUs	IROB	SPLB SPSB SRXB	13.5.2.1* Draft Rev. 1 Dec. 2002	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.9	10.9	13.5.2.1
Human Factors Engineering	All EPUs	IROB		18.0** Draft Rev. 0 April 1996	Specific review questions are provided in the template safety evaluations.		2.11	2.11	10.6	10.9	7.5

*The staff is currently finalizing SRP Sections 13.2.1, 13.2.2, and 13.5.2.1. While these SRP Sections are being finalized, the staff will continue to use the versions issued in December 2002 for interim use and public comment. Once finalized, the staff will use the new versions of these SRP Sections.

**The staff received significant comment on draft SRP Chapter 18.0 that was issued in December 2002 for interim use and public comment. The staff is working on finalizing this SRP. However, due to the significance of the comments received, the staff will use Draft SRP Chapter 18.0, Revision 0, dated April 1996.

MATRIX 12
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Power Ascension and Testing Plan

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Power Ascension and Testing	All EPUs	IEPB	EEIB EMCB EMEB IROB SPLB SPSB SRXB	14.2.1* Draft Rev. 0 Dec. 2002	Entire Section		2.12	2.12	10.4	10.4	14.3, 14.4

*The staff is currently finalizing SRP Section 14.2.1. While this SRP Section is being finalized, the staff will continue to use the version issued for interim use and public comment in December 2002. Once finalized, the staff will use the new version.

MATRIX 13
SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
Risk Evaluation

Areas of Review	Applicable to	Primary Review Branch	Secondary Review Branch(es)	SRP Section Number	Focus of SRP Usage	Other Guidance	Template Safety Evaluation Section Number		Cross Reference to		
							BWR	PWR	PUSAR	CLTR	FSAR
Risk Evaluation	All EPUs	SPSB				Note 1* RG 1.174 RIS 2001-02	2.13	2.13	10.5	10.5	

Notes:

1. The staff's review is based on Attachment 1 to this matrix. Attachment 1 invokes SRP Chapter 19, Appendix D, if special circumstances are identified during the review.

Attachment 13 to PLA-6076

RS-001 Safety Evaluation Template

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The reactor vessel material surveillance program provides a means for determining and monitoring the fracture toughness of the reactor vessel beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the reactor vessel. The
NRC staff's review primarily focused on the effects of the proposed EPU on the licensee's reactor vessel surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC)-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the reactor vessel beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in Standard Review Plan (SRP) Section 5.3.1 and other guidance provided in Matrix 1 of RS-001.

NOTE: In accordance with the provisions of 10CFR50.90, PPL Susquehanna, LLC submitted a request for amendment to Technical Specification 3.5.10 "RCS Pressure And Temperature (P/T) Limits" for the Susquehanna SES Units 1 & 2 in October of 2005 (reference) PLA-5933, PPL Letter to NRC, "Proposed Amendment No. 280 To Unit 1 Facility Operating License NPF-14 And Proposed Amendment No. 249 To Unit 2 Facility Operating License NPF-22: Revise Technical Specification 3.4.10 "RCS Pressure And Temperature (P/T) Limits", McKinny, Britt T. To U.S. Nuclear Regulatory Commission, 10/5/2005. The Pressure/Temperature curves presented in that submittal account for the CPPU operating conditions up to 3952 MWth.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the reactor vessel surveillance withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the reactor vessel capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR Part 50, Appendix H, and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC-14 and GDC-31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Regulatory Evaluation

Pressure-temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The NRC staff's review of P-T limits covered the P-T limits methodology and the calculations for the number of effective full power years specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics. The NRC's acceptance criteria for P-T limits are based on (1) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of RS-001.

NOTE: In accordance with the provisions of 10CFR50.90, PPL Susquehanna, LLC submitted a request for amendment to Technical Specification 3.5.10 "RCS Pressure And Temperature (P/T) Limits" for the Susquehanna SES Units 1 & 2 in October of 2005 (reference) PLA-5933, PPL Letter to NRC, "Proposed Amendment No. 280 To Unit 1 Facility Operating License NPF-14 And Proposed Amendment No. 249 To Unit 2 Facility Operating License NPF-22: Revise Technical Specification 3.4.10 "RCS Pressure And Temperature (P/T) Limits", McKinny, Britt T. To U.S. Nuclear Regulatory Commission, 10/5/2005. The Pressure/Temperature curves presented in that submittal account for the CPPU operating conditions up to 3952 MWth.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the P-T limits for the plant and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the P-T limits. The NRC staff further concludes that the licensee has demonstrated the validity of the proposed P-T limits for operation under the proposed EPU conditions. Based on this, the NRC staff concludes that the proposed P-T limits will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60 and will enable the licensee to comply with GDC-14 and GDC-31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the proposed P-T limits.

2.1.5 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design-basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) 10 CFR Part 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs and (2) Regulatory Guide 1.54, Revision 1, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

Note that, as described in Section 3.13 of the SSES Final Safety Analysis Report (FSAR), for NSSS Systems, the provisions of Reg. Guide 1.54 are not imposed due to the relatively small amount of exposed surface area.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coatings systems.

2.5.1.1.3 Circulating Water System

Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. The NRC's acceptance criteria for the CWS are based on GDC-4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related SSCs. Specific review criteria are contained in SRP Section 10.4.5. Since neither the CWS fluid volume nor flow rate increases at SSES due to the proposed EPU, the proposed EPU is acceptable with respect to the CWS. The licensee's flooding analysis is considered in SE sections 2.5.1.1.1 and 2.5.1.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of ~~the modifications to~~ the CWS and concludes that the licensee has adequately evaluated the system~~these modifications~~. ~~The NRC staff concludes that, consistent with the requirements of GDC-4, the increased volumes of fluid leakage that could potentially result from these modifications would not result in the failure of safety-related SSCs following implementation of the proposed EPU.~~ Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CWS.

2.5.2.4 Main Steam Isolation Valve Leakage Control System

Regulatory Evaluation

Redundant quick-acting isolation valves are provided on each main steamline. The leakage control system is designed to reduce the amount of direct, untreated leakage from the main steam isolation valves (MSIVs) when isolation of the primary system and containment is required. The NRC staff's review of the MSIV leakage control system focused on the effects of the proposed EPU on the amount of leakage assumed to occur. The NRC's acceptance criteria for the MSIV leakage control system are based on GDC-54, insofar as it requires that piping systems penetrating containment be provided with leakage detection and isolation capabilities. Specific review criteria are contained in SRP Section 6.7.

NOTE: The MSIV Leakage Control System has been deleted from the SSES Design Bases.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the MSIV leakage control system and finds that the licensee has adequately accounted for the effects of the proposed EPU on the assumed leakage through the MSIVs. The NRC staff further concludes that the leakage control system will continue to reliably detect and isolate the leakage, as required by GDC-54. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MSIV leakage control system.

2.5.4.2 Main Condenser

Regulatory Evaluation

The main condenser (MC) system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). For BWRs without an MSIV leakage control system, the MC system may also serve an accident mitigation function to act as a holdup volume for the plateout of fission products leaking through the MSIVs following core damage (the MSIV leakage control system at SSES has been eliminated). The NRC staff's review focused on the effects of the proposed EPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the MC system to withstand the blowdown effects of steam from the TBS. The NRC's acceptance criteria for the MC system are based on GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 10.4.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MC system and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MC system. The NRC staff concludes that the MC system will continue to maintain its ability to withstand the blowdown effects of the steam from the TBS and thereby continue to meet GDC-60 with respect to controlling releases of radioactive effluents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MC system.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and residual heat removal (RHR) systems are provided to remove heat from the containment atmosphere and from the water in the containment wetwell. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC-38, insofar as it requires that a containment heat removal system be provided, and that its function shall be to rapidly reduce the containment pressure and temperature following a LOCA and maintain them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by Draft Guide (DG) 1107.

NOTE: SSES does not have safety-related containment for cooling systems, and the spray systems are not safety-related as described in the Section 6.2 of the Final Safety Analysis Report (FSAR).

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The NRC staff finds that the systems will continue to meet GDC-38 with respect to rapidly reducing the containment pressure and temperature following a LOCA and maintaining them at acceptably low levels. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Secondary Containment Functional Design

Regulatory Evaluation

The secondary containment structure and supporting systems of dual containment plants are provided to collect and process radioactive material that may leak from the primary containment following an accident. The supporting systems maintain a negative pressure within the secondary containment and process this leakage. The NRC staff's review covered (1) analyses of the pressure and temperature response of the secondary containment following accidents within the primary and secondary containments; (2) analyses of the effects of openings in the secondary containment on the capability of the depressurization and filtration system to establish a negative pressure in a prescribed time; (3) analyses of any primary containment leakage paths that bypass the secondary containment;~~ (4) analyses of the pressure response of the secondary containment resulting from inadvertent depressurization of the primary containment when there is vacuum relief from the secondary containment~~ (not applicable to SSES because the SSES design does not include secondary to primary containment vacuum breakers); and (5) the acceptability of the mass and energy release data used in the analysis. The NRC staff's review primarily focused on the effects that the proposed EPU may have on the pressure and temperature response and drawdown time of the secondary containment, and the impact this may have on offsite dose. The NRC's acceptance criteria for secondary containment functional design are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and be protected from dynamic effects (e.g., the effects of missiles, pipe whipping, and discharging fluids) that may result from equipment failures; and (2) GDC-16, insofar as it requires that reactor containment and associated systems be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment. Specific review criteria are contained in SRP Section 6.2.3.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the secondary containment pressure and temperature transient and the ability of the secondary containment to provide an essentially leak-tight barrier against uncontrolled release of radioactivity to the environment. The NRC staff concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU and further concludes that the secondary containment and associated systems will continue to provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment following implementation of the proposed EPU. Based on this, the NRC staff also concludes that the secondary containment and associated systems will continue to meet the requirements of GDCs 4 and 16. Therefore, the NRC staff finds the proposed EPU acceptable with respect to secondary containment functional design.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the control room can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room habitability system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE~~whole body, or its equivalent, to any part of the body~~, for the duration of the accident. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed EPU. The NRC staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the NRC staff concludes that the control room habitability system will continue to meet the requirements of GDCs 4 and 19. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in postaccident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., standby gas treatment systems and emergency or postaccident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for ESF atmosphere cleanup systems are based on (1) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE~~whole body, or its equivalent, to any part of the body~~, for the duration of the accident; (2) GDC-41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences (AOOs), and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in postaccident environments following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDCs 19, 41, 61, and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Control Room Area Ventilation System

Regulatory Evaluation

The function of the control room area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE~~whole body, or its equivalent to any part of the body~~, for the duration of the accident; and (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the proposed EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDCs 4, 19, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

2.8.4.5 Standby Liquid Control System

Regulatory Evaluation

The standby liquid control system (SLCS) provides backup capability for reactivity control independent of the control rod system. The SLCS functions by injecting a boron solution into the reactor to effect shutdown. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system to deliver the required amount of boron solution into the reactor. The NRC's acceptance criteria are based on (1) GDC-26, insofar as it requires that two independent reactivity control systems of different design principles be provided, and that one of the systems be capable of holding the reactor subcritical in the cold condition; (2) GDC-27, insofar as it requires that the reactivity control systems have a combined capability, in conjunction with poison addition by the ECCS, to reliably control reactivity changes under postulated accident conditions; and (3) 10 CFR 50.62(c)(4), insofar as it requires that the SLCS be capable of reliably injecting a borated water solution into the reactor pressure vessel at a boron concentration, boron enrichment, and flow rate that provides a set level of reactivity control, and **[DEPENDING ON CONSTRUCTION PERMIT DATE OR ORIGINAL DESIGN]** that the system initiate automatically. Specific review criteria are contained in SRP Section 9.3.5 and other guidance provided in Matrix 8 of RS-001.

Note that the SSES SLCS System is manually initiated.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system will continue to provide the function of reactivity control independent of the control rod system following implementation of the proposed EPU. Based on this, the NRC staff concludes that the SLCS will continue to meet the requirements of GDCs 26 and 27, and 10 CFR 50.62(c)(4) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SLCS.

2.8.5.7 Anticipated Transients Without Scrams

Regulatory Evaluation

ATWS is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC-20. The regulation at 10 CFR 50.62 requires that:

- each BWR have an ARI system that is designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device.

- each BWR have a standby liquid control system (SLCS) with the capability of injecting into the reactor vessel a borated water solution with reactivity control at least equivalent to the control obtained by injecting 86 gpm of a 13 weight-percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel. The system initiation must be automatic.

- each BWR have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff's review was conducted to ensure that (1) the above requirements are met, (2) sufficient margin is available in the setpoint for the SLCS pump discharge relief valve such that SLCS operability is not affected by the proposed EPU, and (3) operator actions specified in the plant's Emergency Operating Procedures are consistent with the generic emergency procedure guidelines/severe accident guidelines (EPGs/SAGs), insofar as they apply to the plant design. In addition, the NRC staff reviewed the licensee's ATWS analysis to ensure that (1) the peak vessel bottom pressure is less than the ASME Service Level C limit of 1500 psig; (2) the peak clad temperature is within the 10 CFR 50.46 limit of 2200 °F; (3) the peak suppression pool temperature is less than the design limit; and (4) the peak containment pressure is less than the containment design pressure. The NRC staff also evaluated the potential for thermal-hydraulic instability in conjunction with ATWS events using the methods and criteria approved by the NRC staff. For this analysis, the NRC staff reviewed the limiting event determination, the sequence of events, the analytical model and its applicability, the values of parameters used in the analytical model, and the results of the analyses. *Insert the following sentence if the licensee relied upon generic vendor analyses* **[The NRC staff reviewed the licensee's justification of the applicability of generic vendor analyses to its plant and the operating conditions for the proposed EPU.]** Review guidance is provided in Matrix 8 of RS-001.

Note that the SSES SLCS System is manually initiated.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]