ENCLOSURE 2

S-C-CBV-MEE-1982, Revision 0

1. Revision Summary

Revision	Date	Description
0	2/19/2007	Initial Issue

2. Purpose

This engineering evaluation (EE) provides the technical basis for Salem License Change Request (LCR) S06-010. The LCR relates to adoption of a new containment response analysis that credits Steam Generator Feedwater Pump (SGFP) Trip and Feedwater Isolation Valve closure to reduce the mass/energy release to containment during a Main Steam Line Break (MSLB). The containment analysis also credits a reduced heat removal capability for the Containment Fan Cooler Units (CFCUs). The LCR also reduces the required Service Water (SW) flow to the CFCUs consistent with the new containment analysis.

This EE also provides justification of the acceptability of predicted containment response per the revised containment analysis documented in WCAP-16503, Revision 3 (Reference 1). In particular, this EE provides reasonable assurance that:

- The assumptions and inputs to the WCAP-16503 relative to Steam Generator Feedwater Pump (SGFP) Trip and Feedwater Isolation Valve (FIV) closure are technically appropriate and consistent with the Salem 1 and 2 design basis,

- The acceptable minimum plant system configurations and capacities are consistent with the WCAP-16503 inputs and assumptions for the SGFP trip and BF-13 FIV closure,

- The surveillance requirements proposed in LCR S06-10 demonstrate that system configurations are maintained consistent with the WCAP-16503 inputs and assumptions for the SGFP trip and BF-13 FIV closure,

- The plant cooling system design capabilities satisfy the requirements stemming from the containment analysis results of the WCAP-16503, considering the reduction in CFCU heat removal capacity, and

- The revised containment temperature/pressure response does not adversely impact safety limits and other plant evaluations and programs.

Finally, this EE presents the basis for the reduced CFCU flow for accident conditions, demonstrating that the CFCU heat removal capacity assumed in WCAP-16503 is satisfied and that the SW system will operate acceptably.

3. Scope

This evaluation is applicable to either Salem Unit. The scope of this EE is limited to the changes in the containment analysis related to:

- Crediting SGFP trip and BF13 FIV closure during the accident events and evaluation of subsequent plant system impacts and
- Reduction in CFCU heat removal capacity and minimum Service Water flow rate, consistent with the bounding containment transient analysis assumptions.

4. Background

PSEG Nuclear has a goal to demonstrate reduced reliance on CFCU cooling during accident conditions to allow any combination of the following: reduced SW flows during an accident, higher fouling, and increased plugging of the CFCU heat exchanger tubes. To support this effort, Westinghouse analyzed various mass and energy (M&E) release scenarios to demonstrate the acceptability of reducing the CFCU heat removal capability credited in the analysis. This analysis is documented in WCAP-16503-NP, Revision 3 (Reference 1). While the Salem containment pressure and temperature analysis was being re-evaluated, other changes were also incorporated to facilitate future major plant modifications. The following changes were incorporated into the containment analysis:

- Reduction in CFCU heat removal capacity,
- Update of the containment coatings thicknesses to reflect as-found plant conditions (Reference 42),
- Salem Unit 2 replacement steam generators, and
- Confirmation of plant design bases and operating procedures (References 40 through 42 and 47).

Changes in analysis modeling assumptions necessary to show acceptable results are to credit the throttling capability of the Feedwater Isolation Valves (BF-13) and the trip and coast down times for the SGFP in the Main Steam Line Break analysis. The discussions provided in Sections 4 and 5 summarize these changes, the impacts and the justification for the change in analysis assumptions.

Salem License Change Request LCR S06-10 (Reference 4) relates to new surveillance requirements necessitated by crediting feedwater pump trip in a new containment analysis. LCR

S06-010 requests a change to the Salem Technical Specifications to add new time response performance requirements for existing plant Engineered Safety Features (ESF) that support automatic main feed flow isolation on a safety injection. The features include automatic trip of the SGFPs, which is not credited by the current Salem Containment Accident Analysis of Record (AOR) (Reference 3). As such, the LCR is supported by a revision to the containment analysis provided by Westinghouse in WCAP 16503 Revision 3 (Reference 1).

4.1. *Current Containment Analysis Inputs and Assumptions*

The current containment pressure/temperature AOR is SECL 96-178 (Reference 3). The existing inputs and assumptions regarding the SGFP trip and FIV closure from the current containment analysis (Reference 3) for Salem 1 and 2 are described below (based on a summary discussion in Reference 1).

Following a Main Steam Line Break (MSLB), feedwater (FW) flow is isolated to limit the M&E released into the containment through the failed steam line. FW isolation includes the following: closure of all FW main and bypass control valves (BF19s and BF40s); trip of the SGFPs; and closure of the motor-operated FIVs (BF13s). UFSAR Section 15.4.8.2.2 (Reference 2) states the following regarding the modeling of the feedwater flow in the safety analyses:

> "There are two valves in each main feedline that serve to isolate main feed water flow following a steam line break. One is the main feed water regulator valve, which receives dual, separate train trip signals from the Plant Protection System on any safety injection signal and closes within 10 seconds (including instrument delays). The second is the feed water isolation valve that also receives dual, separate train trip signals from the reactor protection system following a safety injection signal. This valve closes within 32 seconds (including instrument delays). Additionally, the main feed water pumps receive dual, separate train trips from the protection system following a steamline break. Thus, the worst failure in this system is a failure of the main feed water regulator valve to close. <u>This failure results in an additional 22 seconds during which feed water from the Condensate/Feed System may be added to the faulted steam generator</u>. Also, since the feed water isolation valve is upstream of the regulator valve, failure of the regulator valve results in additional feedline volume that is not isolated from the faulted steam generator. Thus, water in this portion of the lines can flash and enter the faulted steam generator."
>
> "Feed water flow to the faulted steam generator from the Main Feed Water System is calculated using the hydraulic resistances of the system piping, head/flow curves for the main feed water pumps, and the steam generator pressure decay as calculated by the LOFTRAN code. In the calculations performed to match these systems' variables, a <u>variety of assumptions are [sic] made to maximize the calculated flows</u>."

These include:

a. No credit is taken for extra pressure drop in the feedlines due to flashing of water.

b. Feed water regulator valves in the intact loops do not change position prior to a trip signal.

c. All feed water pumps are running at maximum speed."

While the approved MSLB accident methodology allows crediting closure of the BF13 FIV to terminate flow and trip of the SGFP to reduce flow until the BF13 FIV is fully shut, the current containment analyses do not credit the reduced M&E release that would occur with the SGFP trip and while the BF13 FIVs close. This is conservative because the analyses assume full FW flow to the faulted Steam Generator (SG) for 32 seconds, until the BF13 MOV was fully shut.

The AOR (SECL 96-178, Reference 3) assumes CFCU heat removal capacities consistent with a minimum CFCU Service Water flow rate of 2500 gpm (Reference 6). Reduced reliance on CFCU cooling during accident conditions will facilitate improvements in the Salem Service Water System such as reduced SW flows during an accident, higher CFCU fouling, and increased plugging of the CFCU heat exchanger tubes. To support this effort, Westinghouse analyzed various mass and energy (M&E) release scenarios to demonstrate the acceptability of reducing the CFCU heat removal capability credited in the analysis. This new analysis is described below in Section 4.2.

4.2. Revised Containment Analysis Inputs and Assumptions

WCAP-16503 evaluates long term Loss of Coolant Accident (LOCA) and worst case MSLB scenarios. The LOCA and MSLB cases for Salem Unit 1 and Unit 2 are analyzed with the current licensing-basis methods and analysis tools that have been reviewed and approved for the Salem units several times over the duration of plant operation.

The Westinghouse steamline break M&E release methodology was approved by the NRC (Reference 8 of WCAP-16503) and is documented in WCAP-8822 "M&E Releases Following a Steam Line Rupture" (Reference 9 of WCAP-16503). WCAP-8822 forms the basis for the assumptions and models used in the calculation of the M&E releases resulting from a steamline rupture.

Upon a break, WCAP-16503 (Reference 1) assumes pertinent steamline break protection systems actuate a safety injection (SI) signal that starts the SI pumps and will also result in:

- Reactor trip after a 2-second delay.
- Start of auxiliary feedwater (no delay).

- Closure of the Feedwater Regulation Valves (FRVs) after a 10-second delay, and the FIVs after a 32-second delay (only credited if FRV fails open).

- Trip of SGFPs after a 7-second signal processing and mechanical delay with a 7-second coastdown (only credited if FRV fails open).

- Start of CFCUs after a 100-second delay.

The FRV on each of the intact SGs is assumed to close at the time of the SI signal which terminates the main FW flow to the intact SGs. However, the FRV on the faulted loop is assumed to open quickly in response to the steamline break before getting a signal to close. Starting at 0.2 second, the main feedwater flow modeling is based on the faulted loop FRV fully open (and the intact loop FRVs fully closed). For normal response (with no assumed component failures), FW is added to the faulted SG until the faulted loop FRV closes, which occurs 10 seconds after the SI signal.

For the single failure scenario of the faulted loop FRV failing open, WCAP-16503 now assumes that the SGFPs are tripped after a 7-second delay (due to instrument and mechanical delays) and have a 7-second coastdown. However, because the condensate pumps are not tripped from an SI signal, pumped flow (from the condensate pumps through the SGFPs) continues until the FIV is fully closed 32 seconds after the SI signal. In essence, the new analysis revises the amount of flow from the SGFPs through the faulted loop for the period up to closure of the FIV.

The revised modeling remains in conformance with the UFSAR. As indicated above, UFSAR Section 15.4.8.2 states:

> "...the worst failure in this system is a failure of the main feed water regulator valves to close. This failure results in an additional 22 seconds during which feed water from the Condensate Feed System may be added to the faulted steam generator."

The 22 seconds is the difference between the full closure of the FRV (10 seconds) and full closure of the FIV (32 seconds). Although the UFSAR covers this modeling sequence, the original accident modeling was overly conservative as it assumed full FW flow to the faulted SG for 32 seconds, until the FIV was fully shut. The revised modeling in WCAP-16503 credits reduced flow when the SGFP is tripped. It further reduces the flow as FIV closure increasingly throttles the flow from the Condensate Pumps.

WCAP-16503 assumes that upon the SGFP trip (after the 7-second signal and mechanical delays), the SGFP has a 7-second coast-down. During the coast-down, FW flow is assumed to decrease linearly to the flow rate provided by the condensate pumps (through freewheeling SGFPs). The baseline SGFP and condensate pump flow rates were calculated using

Westinghouse's LOFTRAN analysis program and were a function of the transient pressure in the faulted SG.

Closure of FIV terminates the remaining pumped flow from the condensate system. This is modeled assuming a 2-second electronic delay before initiation of the valve closure, 20 seconds of valve closure that have no impact on the FW flowrate, and a linear flowrate reduction during the final 10 seconds of the valve stroke.

Lower CFCU heat removal rates (as a function of containment temperature) are assumed in the WCAP to allow increased Service Water System margin to accommodate future modifications or analysis revisions such as increased plugging, increased fouling factor, and reduced SW accident flow rates. The heat removal rates assumed in the WCAP are still bounded by the CFCU heat removal capacity as defined in calculation S-C-CBV-MDC-1637 (Reference 6). There is no reduction in the number of CFCUs which will be retained operable. For those cases where the single failure is the loss of a safeguards train, three CFCUs and one containment spray pump are available for containment cooling. For other single-failure scenarios, the maximum number of CFCUs could be five and the maximum number of spray pumps could be two.

LCR S06-010 (Reference 4) addresses incorporation of the revised containment response per WCAP-16503 Revision 3 into the design and licensing basis of the Salem units. The Technical Specification (Reference 5) changes identified in LCR S06-010 (Reference 4) are consistent with the WCAP analyses assumptions that credit the SGFP trip and the reduced CFCU heat removal capacity. The CFCU heat reduction assumption facilitates the reduced Technical Specification surveillance requirement of a minimum of 1300 gpm Service Water flow to each CFCU.

5. Evaluation of Inputs to New Containment Analysis

As discussed in Section 4, the containment analysis inputs and assumptions have been changed in WCAP-16503 for the SGFPs and CFCUs relative to previous containment analyses. This included revision to the analyses for the single failure case when the FRV to the faulted SG is assumed to fail open and a reduction in the assumed CFCU heat removal capacity. The relevant input plant parameters for these changes include:

- SI signal trip of the FIV's and any associated time delays.
- SI signal trip of the SGFPs and any associated time delays.
- SGFP coastdown time and flow/pressure characteristics.
- Flow characteristics during FIV closure.
- Minimum CFCU heat removal capacity.

The new inputs/assumptions and corresponding bounding plant parameters are justified in the subsections below.

5.1. *SI Signal Time Delays*

For a MSLB, the SI signal is initiated based on high steam flow coincident with low steam pressure (Reference 1) or high differential pressure between steam lines (Reference 1) or high containment pressure (Reference 1). The signal is generated following a delay of 2 seconds, (Reference 1), after the event parameters are exceeded.

5.2. *SI Signal Trip of FIV's and Associated Time Delays*

The WCAP-16503 analysis assumes a 2 second electronic delay before initiation of the BF13 FIV closure, 20 seconds of valve closure that has no impact on the FW flow rate, and a linear flow rate reduction during the final 10 seconds of the valve stroke. The total stroke time for the BF-13 FIV is 30 seconds (Reference 1). The hydraulic effect on feedwater flow rate is discussed in Section 5.5 below.

The Engineered Safety Feature (ESF) Safety Injection signals to close the FIVs (Reference 9 and Reference 10) are accomplished through relays K621, BB621 and/or BC621 (Reference 10). The SI signal process delay of 2 seconds (Reference 3) prior to FIV actuation assumed in the WCAP has been defined previously and remains unchanged (Reference 3).

The design basis stroke time for the FIVs is 30 seconds per calculation S-1-CN-MDC-0881 Sheet 001 (Reference 13). The 30-second stroke time is also defined in the Salem UFSAR Section 15.4.8.2.2. Results from past tests as documented in calculation S-1-CN-MDC-0881 Sheet 001 Exhibit 1 indicate actual stroke times of about 26 seconds. In addition, testing per Surveillance Procedure S1.OP-ST.MS-0002 (Reference 11) verifies actuation and closure of the BF13 valves based on a criterion of 22.4 to 29.0 seconds from S1.RA-ST.MS-0002 page 6 (Reference 12).

Therefore, it is concluded that the existing plant design logic and testing ensures the 30-second time delay for the BF13 FIV closure assumed in WCAP-16503 is acceptable and bounding, and also within the conditions required per UFSAR Section 15.4.8.2.2.

5.3. *SI Signal Trip of SGFP and Associated Time Delays*

The second change in the Salem WCAP modeling assumptions is crediting the SGFP trip and coastdown. The basis for the Salem trip time delay is developed and compared to similar U.S. plant designs.

The SI signal causes a slave relay (trip solenoid) to change position, creating an imbalance in hydraulic pressure, which shuts the turbine stop valve. Closure of the turbine stop valve isolates steam flow to the turbine and causes the SGFP to begin to coastdown. The SGFP is tripped based on signals to the turbine trip solenoids SV77 and SV84 (References 9 and 10). As described in Section 5.13.7.B of the CBD (Reference 7), the SV77 and SV84 Solenoid Trip Valves are located in the control oil line and when actuated will open to bleed the control oil from the relay valves on the High Pressure Turbine Stop Valve MS43 and the Low Pressure Turbine Stop Valve RS15. Bleeding of the control oil from the relay valves causes the relay valves to close which then bleeds hydraulic oil from the main hydraulic pistons. This then allows the spring and stem forces to close the stop valves.

The SGFP trip response delay and coastdown assumed for the Salem Unit 1 and 2 analyses is comprised of multiple component delays. These component delays are defined based on a combination of known Salem equipment capability, industry accepted values (i.e., as approved by the NRC through various license amendments), and evaluation of equivalent assumptions from other plants with similar equipment. The specific component delays that require definition (Reference 9) for the SGFP trip are:

- SI Signal Process Delay
- Solenoid Trip Valve Delay (a.k.a. slave relay delay)
- Stop Valve (MS43/RS15) Stroke Times
- Delay Margin

There is some variation among the plants that credit SGFP coastdown as to how the individual delays are attributed to each component response. This results in some variation in the timing and duration of the SGFP coastdown and its impact on mass/energy release during a MSLB. Some key inputs are given below.

- For the SI Signal Process Delay, a 2-second delay has been defined previously (Reference 3) and is used in previous containment analyses. No changes to this value are made.
- Diablo Canyon assumes a 5-second total trip delay (2 seconds for signal processing, 1 second for a slave relay delay, 1 second for steam stop valve stroke and an additional 1 second for hardware margin). This is followed by a 5-second pump coastdown (Reference 34) which is an analytical assumption
- Indian Point Unit 3 feedwater trip scenario (Reference 35) assumes a 2 second electronic delay and a 5 second delay on tripping the main boiler feedwater pumps for a total trip

delay of 7 seconds. The feedwater pumps are then assumed to coastdown in 10 seconds (Reference 35), which is an analytical assumption.

For Salem, the total assumed SGFP trip delay is defined as 7 seconds, consisting of: 2 seconds for signal processing, 1 second for a slave relay, 1 second for steam stop valve repositioning and an additional 3 second margin (see Table 5.3-1 below). The 7 second trip delay is followed by the SGFP coastdown as discussed in the next section.

Table 5.3-1 - SFGP Trip Event Timing

Time (sec.)	Sequence of Events
0	Initiation of SI Signal
0 - 2	SI Signal Process Delay (2 seconds)
2 - 3	Solenoid Trip Valve/Slave Relay Delay (1 second)
3 - 4	Turbine Steam Supply Stop Valves (MS43/RS15) Close Stroke (1 second)
4 - 7	Additional Time Delay Margin (3 seconds)

The solenoid trip valve and MS43/RS15 stop valve time delays listed above are based on consideration of equivalent response requirements for turbine overspeed trips and the fact that the valves are designed for fast closure (References 7 and 8).

Other than the SI signal process delay, no current plant procedures exist to routinely verify the time delays associated with the Solenoid Trip Valve and Turbine Stop Valves closing stroke. An open item associated with acceptance of the LCR is establishment of routine surveillance testing to verify the SGFP trip circuit signal and mechanical time delays consistent with other SI signal testing requirements (i.e., once every cycle or 18 months). This testing needs to demonstrate that the total time from initiation of SI signal to closure of the MS43 and RS15 stop valves is completed within 7 seconds to ensure that the logic and time delays used in the WCAP remain bounding.

It is noted that S1(2).OP-ST.SSP-0011(Q) Manual Safety Injection Surveillance Test Procedure (Reference 32) verifies that the SI signal is received at the SGFP control cabinet. Also, procedure S1(2).OP-SO.CN-0002(Q) (Reference 33) performs a manual trip of the steam generator feed pumps from the control room. However, neither of these procedures currently requires measurement of the component time responses.

A review of the current Salem design basis and other similar plants shows that the timing requirements identified above are consistent and achievable. Additional surveillance testing requirements are necessary to ensure that the trip response times are maintained.

5.4. SGFP Coastdown Time and Flow Characteristics

Pump coast down is the time in which the turbine/pump set continues to rotate after shutting the turbine stop valve. During coast down, the pump continues to deliver flow to the steam generator. This period of time is dependent on the momentum of the rotating elements of both the turbine and the pump, which is influenced by the initial speed, brake horsepower of the turbine, characteristics of the rotating elements, bearing efficiency, piping hydraulic resistance, among others.

A survey of other power plants that have credited feedwater pump coastdown in their MSLB containment response analyses has identified a range of values between 5 and 10 seconds (References 31, 34, 35 and Attachment 2). None of the plants have included the coastdown values in their technical specifications and therefore, coastdown times are not subject to surveillance testing.

The Indian Point Main Boiler Feedwater Pump (MBFP) trip safety analysis scenario timing includes a 2 second electronic delay and a 5 second MBFP trip actuation delay. The MBFPs are assumed to coastdown in 10 seconds and the pump discharge valves (BFD-2-21 & BFD-2-22) are assumed to close in 60 seconds, Indian Point Tech Spec 3.7.3.2 and UFSAR 14.2.5.6.

Of particular interest is the license amendment request submitted by Diablo Canyon (Reference 34) to change some ESF response times in their technical specifications. Diablo Canyon broke down the previously assumed feed pump turbine trip/feedwater isolation time of 10 seconds into 5 seconds for the pump trip response and 5 seconds for the pump coastdown (Reference 34). The NRC SER (Reference 37) associated with this amendment request identified the response time for the SGFP turbine trip as reasonable and satisfies the assumptions credited in the feedwater isolation analysis.

Based on information provided in Attachment 2 (Reference 31), the Diablo Canyon turbine/pump set is a typical feedpump design similar to that installed at Salem. Table 5.4-1 compares pertinent turbine and pump parameters. The similarity in many of the parameters, especially, rated flow, discharge pressure, speed, and brake horsepower, indicates that it would be expected that the Salem turbine/pump set would have similar rotational inertia and coastdown characteristics as that at Diablo Canyon.

Figure 5.4-1 below provides a graphical representation of the assumptions made by Salem, Diablo Canyon, and Indian Point Unit 3 to allow comparison of the relative SGFP trip and coast down characteristics after the initiation of the event. The Indian Point and Diablo Canyon data points are included to show that the proposed Salem SGFP coast down times are consistent with other nuclear plants of this type and vintage.

Table 5.4-1- SGFP Characteristics Comparison

Characteristic		Diablo Canyon (Ref. 31)	Salem (Ref. 7 and 8)
Pump Type		Single stage, double suction, centrifugal	Single stage centrifugal pump (UFSAR Table 10.4.11)
Manufacturer		Bryon – Jackson DVSR-(14X14X17)	Worthington 24WGID-171
Rated flow (design)		18,350 gpm @ 1089 psia	18,613 gpm at 370°F
Maximum flow		20,000 gpm	-
Differential Head	Design	2000 ft	2320 ft (884 psi)
	Shutoff	2590 ft	-
NPSH Required	Design flow	285 ft	203 ft
	Max flow	301 ft	-
Efficiency		86%	-
Pump drive		-	9 stage steam turbine
		Westinghouse Model EMM-25	DeLaval Type KJDF
Brake Horsepower	Design flow	9530 bhp	10,970 bhp @ 5530 RPM
	Max flow	9850 bhp	11,600 bhp
Speed		5800 rpm	5530 rpm

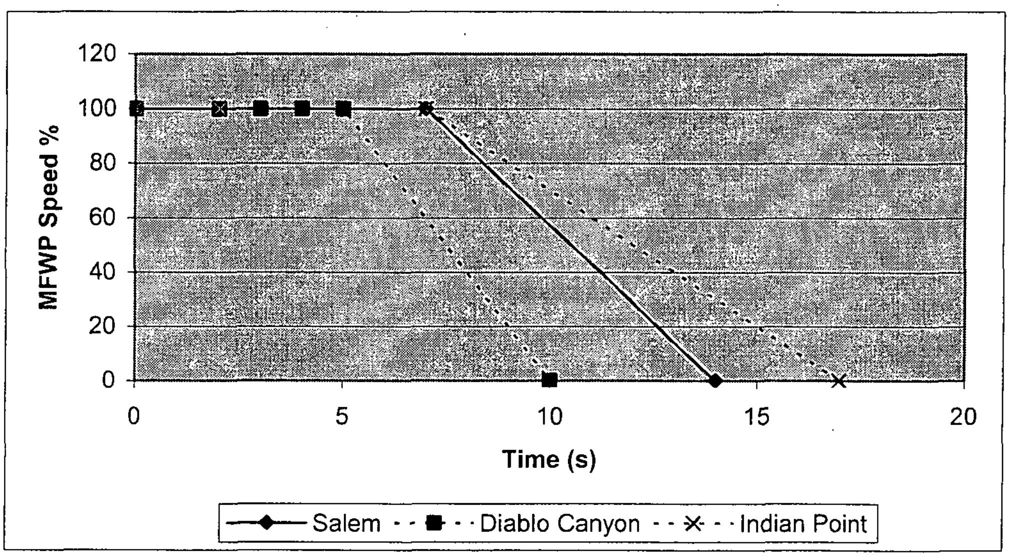

Figure 5.4-1. Comparison of MFWP Coastdown Times and Speed Assumptions

Combined with the signal and mechanical delays (7 seconds) defined above, the complete sequence of events for the SGFP trip used as basis for the WCAP-16503 analysis input is shown below in Table 5.4-2.

Table 5.4-2 - SGFP Trip Analysis Assumptions

Time (sec.)	Sequence of Events
0	Initiation of SI Signal
0 - 2	SI Signal Process Delay (2 seconds)
2 - 3	Solenoid Trip Valve/Slave Relay Delay (1 second)
3 - 4	Turbine Steam Supply Stop Valve Position Change (1 second)
4 - 7	Additional Margin (3 seconds)
7 - 14	MFWP Coastdown (7 seconds)

The total 14 second time defined above in Table 5.4-2 is also more conservative than the total SGFP trip and coastdown time assumed in previous Salem analyses. In particular, Calculation S-1-CN-MDC-0881 Sheet 001 (Reference 13) includes an attachment (document NFU-92-177) which establishes the "Differential Pressure Across BF13 Valve During Closure" for the bounding set of licensing basis accidents. For the same accident event and failure scenario as used in the WCAP (i.e., MSLB with FRV failed open, and with condensate flow), the NFU-92-177 analysis assumed the SGFPs tripped and coasted down to a "free-wheel" speed of 100 rpm within 10 seconds of the transient initiation.

During the 7 second SGFP coastdown, the feedwater flow is assumed to decrease linearly to a flow rate provided by the condensate pumps. The baseline SGFP and condensate pump flow rates were calculated using Westinghouse's LOFTRAN analysis program and were a function of the time variant pressure in the faulted steam generator.

A review of the Salem design basis and other similar plant designs, shows that the Steam Generator Feedwater Pump trip timing and flow coastdown characteristics are consistent and achievable.

5.5. Flow Characteristics during FIV Closure

In addition to crediting the SGFP trip and coastdown for reduced flow to the faulted SG, WCAP-16503 credits BF13 FIV closure for reduced flow. The WCAP analysis model decreases FW flow as a function of increased flow resistance during the valve closure. However, instead of decreasing the flow over the full 30 second design basis stroke time of the valve, the FIV is only credited to close with a linear flow ramp over the last 10 seconds of the 30-second stroke time.

The WCAP analysis assumes a full open valve resistance coefficient for the first 20 seconds of the stroke, even though the valve will have completed about 66% of its closing stroke (i.e., valve will only be approximately 33% open when the model begins the linear decrease in flow). The 30 second valve stroke time does not include the 2 second electronic actuation delay identified in WCAP-16530 Section A.4.2.

BF-13 is a 12-inch motor operated gate valve with a full open flow coefficient of 12,000. In general, gate valves do not significantly affect system flow until they are less than 50% open. Pages 44 thru 50 of the original BF13 MOV Calc S-1-CN-MDC-0881 Sheet 001 (Reference 13) evaluates the effect of BF13 closure on feedwater flow and concludes that the linear flow decrease assumption during the final 5% of the stroke is not valid for the BF-13 operating conditions during a MSLB event. In particular, Pages 49 and 50 of MDC-0881 (Reference 13) identify high flow through BF13 (>5000 gpm) even down to 5% open because of the choked flow effects - i.e., it specifically states the valve Cv does not change in a linear manner.

As a check of the validity of the WCAP-16503 linear flow decrease assumption, a comparison of feedwater flow rate as a function of time was developed. The comparison assumes a constant hydraulic resistance value for feedwater system components with the exception of BF-13, whose hydraulic resistance is a function of valve position. The hydraulic resistance of the system was set at a value that gave a feedwater flow rate of approximately 2500 lbm/sec at the gate valve position of 100% open. This value closely matches the 2467 lbm/sec flow described in Westinghouse Calc Note CN-CRA-03-49 for Case 8 of PS-PSE-0727. [Note: Case 8 represented feedwater flow with 0 psia SG pressure and MFW pumps off (condensate pumps only)]. Figure 5.5-1 below shows a plot of the feedwater mass flow rate as a function of the BF-13 stroke time for the conditions described above. As shown, the flow begins decreasing rather quickly during the last 8-10 seconds of the stroke time.

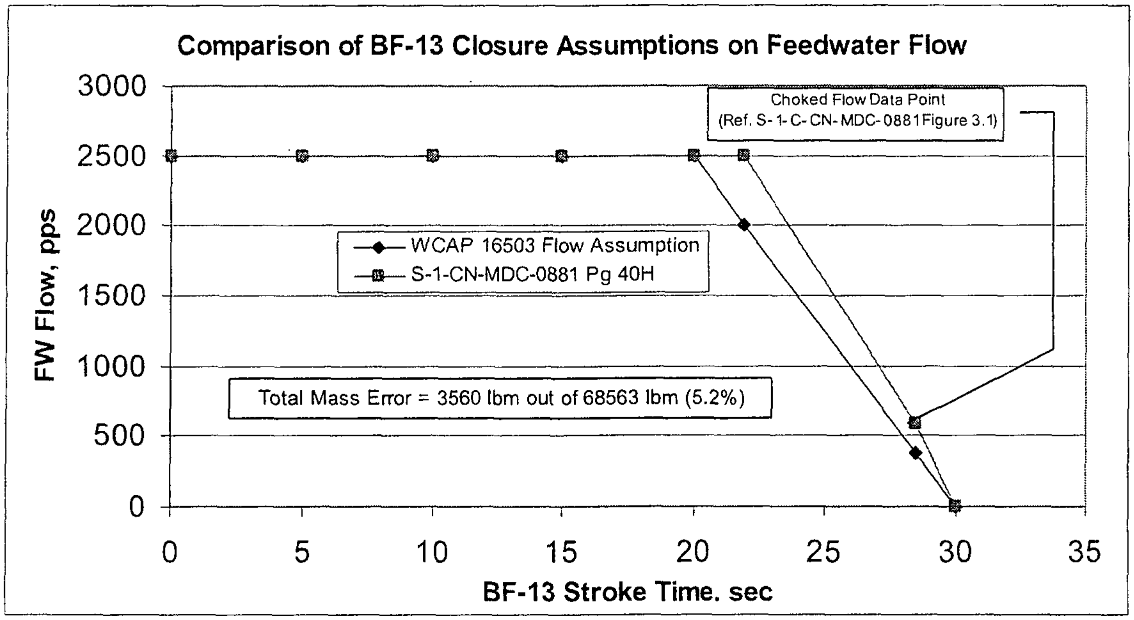

Figure 5.5-1. Impact of BF-13 Closure Flow Assumptions

Figure 5.5-1 shows that the calculated feedwater mass flow will slightly exceed the linear flow decrease assumed in the WCAP-16503 MSLB analysis but the mass addition difference to the faulted steam generator is considered to be within the analytical uncertainty limits of the original MDC-0881 calculations. The MDC-0881 calculation assumes choked flow during BF-13 throttling after 22 seconds. Experimental choked flow data for gate valves are generally not well defined, which results in greater uncertainty associated with results from MDC-0881 (Reference 13) and which would tend to support a conclusion that a 5 Percent difference in calculated choked flow is reasonable. The as-tested BF-13 stroke time of 26 seconds (Reference 13) provides additional rationale for concluding that the actual added feedwater mass injected into a faulted steam generator will be less than the assumed value from WCAP-16503. Considering the conservatism in flow assumed during the first 20 seconds of the valve stroke, assuming a linear flow reduction in the total system flow over the final 10 seconds of BF-13 valve stroke time is considered to be a reasonable assumption. The 30 second valve stroke time does not include the 2 second electronic actuation delay identified in WCAP-16530 Section A.4.2.

Calculation S-1-CN-MDC-0881, Sheet 001 (Reference 13) documents the analysis of the BF13 MOVs to show design capability consistent with the design basis conditions assumed for the WCAP (i.e., valve closure with the SGFP pump tripped). Also, this calculation references differential pressure (DP) testing of the BF13 valves in 1993 performed under Work Order 930413087. The test was performed at the design basis DP of 631 psid defined in the calculation Exhibit 3. Although margins were small, the valve was capable of closing against the design basis DP. Consequently, it is concluded that BF13 valve closure during the events evaluated in the WCAP are covered by the design basis analyses.

Another consideration in establishing the acceptance of the proposed WCAP-16503 assumptions is the crediting of non safety related equipment such as the BF-13 FIV valves and the SGFP trip function as it relates to MS43 and RS15 and the SGFP coast down characteristics in the mitigation of mass addition to a faulted steam generator during a MSLB event. Westinghouse reviewed the containment analysis MSLB modeling basis assumptions and concluded that the NRC has previously accepted the crediting of non safety related equipment as a response to a single active failure. The acceptability of this position is documented in NUREG-0800 Standard Review Plan Section 6.2.1.4 – "Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures":

> *"For the assumed failure of a safety grade steam or feedwater line isolation valve, operation of nonsafety grade equipment may be relied upon as a backup to the safety grade equipment. In this event, the CSB reviewer will confer with the ASB and MEB reviewers to ensure a consistent staff position regarding the acceptability of the design criteria for the nonsafety grade equipment".*

The NRC's position regarding the crediting of non safety related equipment for the specific case of a single active failure of the feedwater or main steam isolation valves was also addressed by NUREG-0138 and NUREG-0933.

NUREG-0138, written in the late 1970's states:

> *"In the event of a steamline break inside containment, it is necessary to isolate the main feedwater to the steam generator associated with the failed line to preclude overpressurizing the containment and to limit the reactivity transient. If the single active failure postulated for this accident is the failure of the appropriate safety grade main feedwater isolation valve to function, then credit is taken for closing the nonsafety grade main feedwater control valve or tripping the feedwater pump in that line. The rationale for reliance on these 'non-safety grade' feedwater components is similar to that presented above for the steamline valves. ... Thus, the staff believes that it is acceptable to rely on these non-safety grade components in the steam and feedwater systems because their design and performance are compatible with the accident conditions for which they are called upon to function. It is the staff position that utilization of these components as a backup to a single failure in safety grade components adequately protects the health and safety of the public."*

NUREG-0933, written in December 1997, revisits this subject. This NUREG is titled, "A Prioritization of Generic Safety Issues," and lays out a systematic approach for determining whether an issue is deserving of further attention. In section 2, item a-22 includes:

> *"In the event of a steam line break inside containment, it is necessary to isolate the main feedwater to the steam generator associated with the failed line to preclude overpressurizing the containment and to limit the reactivity transient. If the single active failure postulated for this accident is the failure of the appropriate safety-grade main feedwater isolation valve to function, then credit is taken for closing the nonsafety-grade main feedwater control valve or tripping the feedwater pump in that line. Issue 1 in NUREG-0138 centered on the reliability of such nonsafety-grade equipment."*

The conclusion from the new evaluation of this effort is that it is "of such low safety significance that it need not be considered further." The NRC's previous conclusion stands, that as a backup to a single failure, a non-safety grade feedwater isolation valve or pump trip can be credited in steamline break mass/energy release safety analyses.

The discussion above provides the basis for the conclusion that BF-13 stroke time, hydraulic characteristic and mechanical actuator design are adequate to meet the timing assumptions in WCAP-16503 (Reference 1).

6. Evaluation of Analysis Results

`The containment temperature/pressure responses calculated in WCAP-16503 differ from the current Analysis of Record (AOR) (Reference 3) due to the decreased heat removal capability for the CFCUs, changes in the containment coating thicknesses and passive heat sink thermal characteristics, and the Salem Unit 2 steam generator replacement. The impact of the new analyses on plant systems and components needs to be evaluated to ensure design capacities provide sufficient margin in bounding the containment analysis results. The following areas need to be addressed:

- Overall Containment Response
- Impact on UFSAR Chapter 15 Events and Other ECCS/Heat Removal Systems
- Impact on Dose Analyses
- Impact on Appendix J Test Requirements
- Impact on Environmental Qualification (EQ) of Equipment Inside Containment

- Impact on CFCU SW Piping Temperature Analyses
- Impact on Pressure Locking/Thermal Binding (PL/TB) Analyses
- Impact on Generic Letter 96-06 Analyses

The following sections discuss the key results of the WCAP relative to plant system capabilities applicable to these areas.

6.1. Containment Response

The containment design functions and parameters are unchanged. This includes the maximum containment pressure and temperature at the beginning of the postulated accident (i.e., containment limits during normal power operation) and the allowable, peak accident pressure and temperature. In addition, the peak accident pressure and temperatures are not significantly changed from the present AOR, SECL 96-178 (Reference 3), as can be seen in Table 6.1-1.

Table 6.1-1-Containment Analysis Peak Conditions

DBA Case	Peak Press SECL 96-178	Peak Press WCAP-16503	Peak Temp SECL 96-178	Peak Temp WCAP-16503
LOCA	41.2 psig [1]	U1: 40.9 psig U2: 43.5 psig	263.3 °F [1]	U1: 262.1 °F U2: 265.9 °F
MSLB	45.1 psig [2]	U1: 41.0 psig U2: 45.6 psig	351.0 °F [3]	U1: 348.2°F U2: 349.6°F

Notes:
1) Reference 3, LOCA Fuel Upgrade/Margin Recovery Program
2) Reference 3, MSLB Case II, Feedwater Regulating Valve Failure
3) Reference 3, MSLB Case VII, MSIV Failure

As described in UFSAR Section 3.8.1.1 and 3.8.1.6.1, the Salem containment includes a welded steel liner anchored to the inside face of the concrete shell by means of embedded structural members so that it forms an integral part of the entire composite structure under all loadings. The liner ensures a high degree of leak tightness. The liner analysis is summarized in UFSAR Section 3.8.1.4.1.

The maximum tensile stress on the liner plate occurs during the containment pressure test, when there is no concurrent temperature rise. The maximum compressive stress occurs with a MSLB since the MSLB normally results in a higher temperature but lower pressure than the LOCA. WCAP-16503 (Reference 1) revised the containment analysis to include effects of the CFCU margin recovery project, Replacement Steam Generator project, revised heat sinks, as found coatings thickness and other miscellaneous changes. The revised peak containment temperature is 349.6°F vs. 348.2°F (difference of +1.40°F) for MSLB case. This peak temperature exceeds the design inputs used in liner thermal calculation (Reference 51). Salem calculation S6O-1800 (Reference 51) is the basis for the containment liner buckling analysis (Reference 53). It is noted that although the peak pressure during the transient has increased, it is not critical to the containment liner evaluations (References 52 and 53) as addressed below.

As a result of an increase in the containment temperature, the peak liner temperature increase is less than 1.4°F from the 294.9°F shown in S6O-1800 (Reference 51) due to changes in the outside film coefficient. As a result of the increase in the containment pressure, the Uchida heat transfer co-efficient will increase, which reduces the thermal resistance between the liner and the containment air/steam mixture. Consequently, the liner mid-plane temperature will increase. The exact amount of increase is expected to be small and bounded because the actual liner wall stress is below the allowable stress, as discussed below. Conservatively, a 1.4°F temperature increase in the liner average wall temperature will be used for assessing the impact on the containment liner anchors and the containment liner buckling analysis. A 1.4°F increase in the liner wall temperature will result in a 0.6% (0.050 inch) increase in the unrestrained thermal growth of the liner.

Containment Liner Anchors

Review of Calculation 6SO-2027 (Reference 52) shows that the temperature profile for the analysis was obtained from Calculation 6S0-0791-004 (Reference 48). Review of Calculation 6S0-0791-004, Attachment 2 shows that the governing temperature profile used has a peak temperature of 351.3°F which bounds the WCAP-16530 peak temperature of 349.6°F.

The cylindrical and dome liner shear deflections are 14% and 12% of the anchor deflection capability (Reference 52) which represent a significant margin to accommodate an increase in Uchida heat transfer coefficient and on liner mid-plane temperature.

It is concluded that the current design basis calculation (Reference 52) bounds the increase in the peak MSLB containment transient temperature and containment liner anchor are capable of supporting the slight increase in containment peak temperature.

Containment Liner Buckling Evaluation

The containment liner buckling analysis (Reference 53) uses the containment temperature profile developed in calculation 6S0-1800 and the corresponding containment pressure to evaluate the containment liner susceptibility to structural buckling. The results of the analysis demonstrate adequacy of the liner to withstand the MSLB temperature transient. In addition, a significant level of containment liner stress margin exists to be able to accommodate the 1.4°F increase in containment peak temperature and the increase in Uchida heat transfer coefficient and liner mid-plane temperature. It is noted that the 1.4°F increase in the liner temperature is equivalent to a 0.6% increase (0.050 inch) in the liner thermal growth.

For the cylindrical portion of the liner, the maximum stresses (Reference 53) are:

σ_{hoop} = -17.4 ksi < 28.3 ksi minimum yield stress or 38% margin

σ_{long} = -22.1 ksi < 28.3 ksi minimum yield stress or 22% margin

In addition, the increase in the containment pressure has beneficial effect. A higher containment pressure will result in greater tensile stress, which will reduce the compressive stresses obtained in this calculation. This will increase the margins documented above.

For the dome portion of the liner the maximum stresses (Reference 53) are:

σ_{hoop} = -18.3 ksi < 28.5 ksi minimum yield stress or 36% margin

σ_{long} = -20.8 ksi < 28.5 ksi minimum yield stress or 27% margin

Note that the slight difference in yield stress is a result of the dome liner temperature is slightly lower than the cylindrical portion of the liner. The same discussion of pressure effect as above applies.

Based on the significant level of stress margin, it is concluded that the revised containment analysis that results in an increase of 1.4°F in peak liner mid-plane temperature and increase in the containment peak pressure has an insignificant effect on the containment liner adequacy to perform its intended design function.

Conclusion

The containment liner and anchor design capacities bound the peak containment pressure and temperature response results documented in WCAP-16503.

6.2. UFSAR Chapter 15 Events and Other ECCS/Heat Removal System Impacts

The revised Salem 1 and 2 containment analysis, WCAP-16503 Revision 3, evaluates the containment pressure and temperature response due to a reduction in the design basis heat removal capacity of the CFCUs. The results of the containment analysis require evaluation relative to potential impacts on other accident events and heat removal system capabilities. These impacts include:

- Salem UFSAR Chapter 15 event analyses.
- RHR, CCW and SW system thermal-hydraulic performance.

The ability of the revised containment analysis to accommodate the reduced CFCU heat removal capacity is primarily due to several containment analysis modeling refinements. These refinements are consistent with the current Salem design and licensing basis but take credit for conservatisms used in the previous containment AOR. The analysis refinements (Reference 25) are summarized below.

- MSLB

  - In the AOR, the Westinghouse values for the high steam flow trip setpoint assumptions included an environmental allowance term that is not required. The analytical trip setpoints for the AOR were significantly overly conservative. This allowance has been removed from the trip setpoint calculated for the MSLB cases, which results in the trip occurring sooner in the event timing, thereby reducing the M&E release. (EA-CFCU-03-005 dated 10/20/03)

  - The end of cycle moderator density coefficient (MDC) was reduced from 0.52 to 0.45 delta-K/gm/cc, which reduces the peak power due to the cooldown and provides an additional reduction in the M&E release. (EA-CFCU-03-005 dated 10/20/03)

  - For MSLB events where the single failure is the failure of the FRV to close, it is acceptable to credit the trip of the SGFPs from the SI signal, which provides a reduction in the M&E release. (EA-CFCU-03-04 and Assumption of WCAP-16503, discussed above)

  - For the small Double Ended Ruptures, the model was corrected for the treatment of the forward break flow from the faulted SG. The AOR, was overly conservative by taking mass out the break, without reducing the mass in the faulted SG by the same amount. Removing this conservatism provides an additional reduction in the M&E release.

  - PSEG Nuclear provided Westinghouse more accurate Auxiliary Feedwater flow rates, which improve the M&E release profile. (EA-CFCU-03-004 dated 7/10/03)

- LOCA

  - WCAP-16503 has modeled LOCA Injection phase containment spray flow rate as a function of containment pressure and temperature. The AOR established a conservative minimum spray flow rate at the peak containment design pressure. (WCAP-16503 Table 6.1-5)

6.2.1. Impact of Reduced CFCU Capability on UFSAR Chapter 15 Events

A review of the Salem UFSAR Chapter 15 events shows that the only accidents which are impacted by a change in the CFCU modeling parameters are M&E release events such as LOCA, MSLB and Feedwater Line Break (FWLB) Containment Analyses. For the LOCA transient impacts, the containment environment is considered for three aspects: core response, containment response and dose.

Core Response

The core response is most limiting when the containment conditions minimize back pressure since this increases the blowdown and reduces the effectiveness of the ECCS. The LOCA core response (10CFR50.46 – PCT) is conservatively biased by minimizing the containment backpressure such that the safety injection effectiveness is minimized (the core becomes the highest resistance flow path). This bias is the result of assuming that the SW temperature supplied to the operating CFCUs is cold (32°F), and that RWST water being supplied to the containment sprays is cooler then water being provided to the safety injection system. Also, containment spray flow is maximized based on minimum containment pressure (7302 gpm at 10 psig) to conservatively reduce the containment backpressure. Also note that none of these assumed boundary conditions rely on the minimum CFCU heat removal capacity as the primary means of maintaining containment pressure. Thus, any reduction in the accident capability of the CFCUs has no bearing on the LOCA core response.

Containment Response

The bounding containment integrity analyses are the Large Break LOCA (LBLOCA) and the MSLB-Inside Containment events. The containment integrity analysis relies on two heat removal paths to maintain containment pressure and temperature conditions. The CFCU air-to-water heat exchangers reject containment energy to the SW System and the Containment Spray System removes containment energy by using a spray droplet direct contact heat exchange to transfer energy from the containment atmosphere to the containment sump. The energy in the containment sump is transferred out of containment via the Residual Heat Removal (RHR) heat exchanger and Closed Cooling Water (CCW)/SW Systems. The major changes in the containment integrity analysis consist of the modeling refinements previously described in Section 6.2, which are sufficient to offset the impact of the reduced CFCU heat removal capacity.

Dose

The potential dose impacts, due to reduced CFCU heat removal capacity are bounded as the design basis assumptions concerning the number of operating CFCUs (three of five) and the thermal-hydraulic transient operation of the Containment Spray System, are not affected; this will be discussed further in Section 6.3. The Salem design basis only credits Containment Spray iodine removal effectiveness during the LOCA injection phase based on a single failure of an entire ESF train. This assumption results in 3 of 5 CFCU being available to ensure adequate mixing of the containment ambient air as well as operation of a single Containment Spray Train, which controls containment spray droplet size and pH, as described in UFSAR Section 6.2.3. The Containment Building and Auxiliary Building leakage rates are unaffected by the revised containment analysis as the peak containment pressure and temperatures are less than the design basis values described in the Salem UFSAR. Therefore, there is no impact on offsite dose rates due to the reduced CFCU heat removal capacity.

One other high energy line break not previously discussed in this evaluation is the rupture of a feedwater line. From a containment response aspect, this event is bounded by the MSLB event, so it is not explicitly analyzed (or even discussed in the Salem UFSAR). This event is considered from a core heat-up aspect, such that the break area is chosen to maximize the blowdown discharge rate and challenge the Auxiliary Feedwater (AFW) system for decay heat removal. The containment is assumed to stay fixed at atmospheric pressure as it is more limiting in terms of break flow and the capability of the AFW system. Therefore, reduced accident CFCU heat removal capability will have no impact on this event.

Conclusion

The revised containment analyses in WCAP-16503 Revision 3 do not adversely impact the design basis events described in Chapter 15 of the UFSAR.

6.2.2. Impact of Reduced CFCU Capability on RHR, CC and SW System Thermal-Hydraulic Performance

The changes in the thermal conditions in the containment sump due to the reduced CFCU heat removal capacity will be experienced by the other containment heat removal systems (RHR/CCW/SWS) during the transition to the LOCA Recirculation Phase. The containment integrity analysis uses a coupled RHR/CCW/SWS thermal model to calculate the RHR heat exchanger outlet temperatures that would be supplied to the Containment Spray System and for containment cooling. To verify that the increase in containment cooling heat load can be accommodated by the CC and SW Systems, intermediate system temperatures and heat exchanger duties were evaluated during the transient using an indirect e-NTU heat exchanger analysis method (References 21 and 30). The assumed thermal conditions applied in WCAP-16503 Revision 3 were also used for this analysis. Containment integrity analysis assumptions can be found in Table 6.2-1.

Table 6.2-1-Non-CFCU Containment Heat Removal Assumptions

Parameter	Analysis Assumption
RHR Heat Exchangers	
Units Operating	1
Minimum Safeguards Recirculation Switchover Time	1748.3 sec
Heat Capacity, UA	1.75E6 BTU/hr-°F
Tubeside Flow (CC)	4000 gpm
Shellside Flow (RHR)	3200 gpm
Component Cooling Heat Exchangers	
Units Operating	1
Heat Capacity, UA	4.013E6 BTU/hr-°F
Tubeside Flow (SW)	8000 gpm
Shellside Flow (CC)	4140 gpm
Additional CC System Heat Loads	2.0E6 BTU/hr
Tubeside Supply Temperature (SW)	93°F

The design basis assumption for CCW supply temperature as stated in VTD-304209 (Reference 22) is 120°F during the LOCA Recirculation phase. A more conservative SW supply temperature of 93°F was also specified by PSEG Nuclear to bound the existing design basis temperature of 90°F. A supplemental calculation (Reference 30) indicates that the peak CC supply temperature during initiation of LOCA Recirculation is 111.0°F and 112.0°F for Salem Units 1 and 2, respectively. This analysis shows that the reduction in the CFCU heat duty can be accommodated within the existing RHR/CCW/SWS system licensing basis.

A review of the Salem Thermal Modes calculations (References 23 through 25) shows that the revised temperature distributions associated with this analysis, as summarized in Table 6.2-2, are bounded by the existing design basis thermal mode calculations and thus the existing calculated RHR/CC/SW piping thermal stresses are still bounded.

Table 6.2.- 2-Bounding Piping Analysis Temperatures

	Piping Analysis Supply Temperature	Piping Analysis Return Temperature	Bounding WCAP-16503 Supply Temperature	Bounding WCAP-16503 Return Temperature
RHR System (S-C-ZZ-MEE-0785 Revision 2 Attachment 8.1A)	263°F	225°F	257.8°F	173.5°F
CCW System (S-C-ZZ-MEE-0780 Revision 1 Attachment 7.2 Sheet 1)	135F°	200°F	112.0°F	174.2°F
SW System (S-C-ZZ-MEE-0784 Revision 4 Attachment 8.1 CD# H584 Rev 0)	95F°F	195°F/221°F (Note 1)	93°F	125.0°F
Notes	1) 221°F is the maximum faulted return temperature in 1 CFCU return line per S-C-CBV-MDC-1637 Rev 0.			

Conclusion

The increased heat rejection demand on the CCW and RHR systems due to the reduction in CFCU capability is within the existing RHR/CCW/SWS system licensing basis. Also, the associated piping temperature increases are bounded by the existing design basis thermal modes so pipe thermal stresses are bounded.

6.3. DOSE Analyses Impact

The Alternate Source Term (AST) dose calculations (References 19 and 20) address potential accident dose rates outside of the plant and in the Control Room associated with radiologically significant accidents. The only UFSAR Chapter 15 event that is common to the AST dose calculation and the Containment Integrity Analysis, WCAP-16503, is a LBLOCA.

The AST dose calculation includes the post LOCA radionuclide groups identified in Table 6 of NRC Regulatory Guide 1.183. The potential post LOCA activity release paths are identified as:

- Containment Leakage,
- ESF Leakage in the Auxiliary Building,
- Containment Pressure-Vacuum Relief Line Release, and
- ESF Leakage to the RWST.

Each release path has been evaluated to determine the impact of contamination migration from primary containment and the resulting dose to the public and the Control Room operators.

Containment Leakage

Primary containment is the main physical barrier that prevents the release of core radionuclide activity after a beyond design basis LBLOCA. The AST calculations, S-C-ZZ-MDC-1945 and S-C-ZZ-MEE-1797 (References 19 and 20), assume a level of containment atmospheric mixing associated with a minimum of 2 operating CFCUs. The revised Containment Integrity Analysis, WCAP-16503, assumes a minimum of 3 out of 5 CFCUs are operable during the post LOCA period, which is bounding relative to the AST dose calculation assumption.

Another primary containment assumption is the extent, timing, duration and effectiveness of containment spray necessary to capture and transport radionuclide aerosols to the containment sump; this is discussed in more detail below. The extent and effectiveness of containment spray on the removal of radionuclides from the containment atmosphere is a function of the spray nozzle differential pressure, water temperature and water pH. The containment spray nozzle droplet size distribution, spray pattern and droplet size impact the effectiveness of radionuclide capture from the containment atmosphere.

The effectiveness of the containment spray function was originally based on an iodine removal model, UFSAR Section 6.2.4.1, that assumes a peak containment pressure and temperature of 47.0 psig and 271°F. WCAP-16503 calculates a LOCA peak pressure and temperature of 43.5 psig and 265.9°F at approximately 485 seconds into a LBLOCA event. The Salem UFSAR, Section 6.2-52/53, states that the mass transfer term used in the iodine transport model improves with decreasing containment atmospheric pressure, thereby improving the effectiveness of iodine removal from the containment atmosphere. Therefore, the containment spray effectiveness used in the AST dose calculation is still bounding relative to the revised Containment Integrity Analysis.

The duration of containment sprays during the LOCA injection phase is the same for the WCAP-16503 analysis and the AST dose calculation. For the LOCA recirculation phase, the WCAP-16503 analysis does not credit containment spray to provide additional containment cooling, which will result in higher long term containment pressures and temperatures and is conservative. The AST dose calculation assumes that the operators manually reestablish containment spray within 10 minutes after the RWST switchover to the Containment Sump and continue spray operation for at least 4 hours after a LBLOCA event. Therefore, the pressure/temperature profile calculated in the WCAP-16503 analysis is conservative and bounding as it assumes a minimum level of containment cooling and the highest containment pressures and temperatures.

The containment sump pH depends on the volume of ECCS injected water and the total volume of spray additive introduced into containment during the LOCA injection phase. WCAP-16503 does not impact previous RWST drawdown analysis and thus does not impact containment sump pH.

It is concluded that the results of WCAP-16503 (Reference 1) do not have an impact on the AST dose calculations.

Auxiliary Building Leakage

During the LBLOCA recirculation phase, radioactive containment sump water is circulated through the ECCS system, which is partially located in the Auxiliary Building. ECCS system fluid leakage during this operating alignment will result in activity releases, which are addressed in the AST dose calculation. The AST dose calculation assumes that ECCS fluid leakage occurs no earlier than 20 minutes after a LBLOCA initiation. The WCAP-16503 analysis assumes that the containment sump recirculation is initiated no earlier than 29.1 minutes (1748.3 sec) after a LBLOCA event, which is conservative relative to the AST dose calculation.

The AST dose calculation assumption for the Salem plants requires that the design basis ECCS leakage during LBLOCA recirculation of less than 1 gallon per hour be increased to 1 gallon per minute, S-C-ZZ-MDC-1987 Revision 1 (Reference 46) Section 3.6, and then doubled to 2 gpm, NRC Regulatory Guide 1.183. Then a portion of the ECCS fluid leakage is assumed to flash to an airborne vapor, which is then transported throughout the Auxiliary Building. The AST dose calculation assumes that 10% of the leakage is vaporized, based on a bounding enthalpy difference at the design containment saturation temperature of 271°F, Salem LCR S03-05 Attachment 1 Page 14. The calculated ECCS fluid vaporization rate is 0.02673 ft^3 per min (2 gpm / (7.481 gal/cuft) x 10%) at the assumed AST dose calculation conditions, Salem LCR S03-05 Attachment 1 Page 14.

The WCAP-16503 analysis credits ECCS suction switchover to the containment sump occurring at 1748.3 seconds and results in an estimated containment sump temperature of 258.6°F (Reference 1). The corresponding vapor leakage rate from the ECCS system into the Auxiliary Building is 0.0130 ft^3 per min (2 gpm/7.481x4.84%) of ECCS fluid for an assumed 2 gpm ECCS leakage rate, Salem LCR S03-05 Attachment 1 Page 14. The corresponding leakage vaporization is 5.27 Percent enthaply flash fraction and is bounded by the AST dose calculation assumption of 10 Percent, Salem LCR S03-05 Attachment 1 Page 14. The enthalpy flash fraction is a function of the containment sump temperature and is defined as the liquid enthaply difference between the sump water temperature and Auxiliary Building temperature divided by the latent heat of vaporization at the Auxiliary Building temperature. A vaporization leakage fraction of 4.84 Percent that is less than analyzed fraction of 10 Percent indicates that the amount of airborne activity leakage into the Auxiliary Building assumed in the AST dose calculation is not impacted by the results of the WCAP-16503 analysis (Reference 1). The AST dose calculation is conservative relative to the extent of ECCS fluid airborne leakage into the Auxiliary Building that would result in increased dose to the Control Room operators and to the public.

Containment Pressure-Vacuum Line Release

The Containment Pressure-Vacuum line release path is not impacted by the WCAP-16503 analysis as actuation of the Containment Pressure-Vacuum line event only occurs simultaneously with the initiation of a LBLOCA but before containment isolation, Salem LCR S03-05 Attachment 1 Page 14. Containment response up to the time of complete containment isolation for a LBLOCA, which is initiated by a P-2 (Hi-Hi Containment Pressure) signal at 4.4 seconds into the event (Reference 1) is unchanged from the AOR results. So the results of the WCAP-16530 analysis do not impact the AST dose calculation.

ESF Leakage to RWST

Salem calculation S-C-ZZ-MEE-1797 (Reference 20) estimates that the back leakage from the ECCS to the RWST during a LBLOCA is no greater than 100 cc/hr. The AST dose calculation considers this level of leakage to be negligible and does not credit any dose contribution from the RWST back leakage release path. The WCAP-16530 analysis does not impact the AST dose calculation for this leakage path.

Conclusion

A review of the Salem design basis for Alternate Source Term dose calculations shows that the revised Containment Integrity Analysis, WCAP-16503, does not challenge any of the assumptions that are part of the AST design basis.

6.4. Containment Leak Rate Testing Impact

Per Section 6.8.4.f of the Salem Technical Specifications (Reference 5), the 10CFR50 Appendix J Containment Leak Rate testing is defined as follows:

> "A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995.
>
> The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 47.0 psig.
>
> The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day."

Under Option B, the method of implementation is per NEI 94-01 which in turn endorses ANSI 56.8-1994. Salem uses the "Type A" test which is based on DBA containment pressure and system alignments. Per Section 3.2.11 of ANSI 56.8-1994 the test pressure for a Type A Test Pressure shall not be less than 0.96Pac, nor exceed Pd, where:

- Pac (psig) - The calculated peak containment internal pressure related to the DBA
- Pd (psig) - The containment design pressure

Section 6.2 of the UFSAR it indicates that the Type A test pressure is based on the containment design pressure of 47.0 psig, not the calculated accident pressure. Hence, the change in calculated containment response has no impact on integrated leak rate testing.

Conclusion
Since the design pressure value bounds the peak pressure calculated in WCAP-16503 and is not being changed, the Appendix J testing requirements are not impacted.

6.5. Environmental Qualification Impact

The environmental qualification (EQ) of critical equipment inside containment is necessary to ensure that safety related equipment exposed to the harsh environment of a design basis event, such as a LOCA or a MSLB, can reliably perform its design function. The EQ analyses of critical equipment are based on composite curves that envelope the estimated temperature, pressure and radiation environments during a design basis event. These composite curves are defined in the Salem Environmental Design Criteria (EDC) (Reference 15).

The current configuration of Salem Units 1 and 2 include the original Westinghouse Model F and Model 51 steam generators, respectively. In the near future, Salem Unit 2 will be replacing its Model 51 steam generators with Frammatone ANP Model 61/19T replacement steam generators. The WCAP-16503 containment response analysis (Reference 1) evaluates Salem Units 1 and 2 with the original steam generators (OSG) and Salem Unit 2 with the replacement steam generators (RSG). The bounding temperatures and pressures used for evaluating the environmental qualification of safety related equipment in containment are for the Unit 2 RSG containment analysis, WCAP-16503 Appendix A (Reference 1).

Containment Pressure Impact
The containment pressure increase attributable to the Unit 2 RSG has been determined to be bounded by the current design basis composite pressure curve of 47.0 psig (Reference 16) and will not impact previously analyzed EQ equipment.

Containment Temperature Impact
WCAP-16503 (Reference 1) reports the Unit 2 RSG containment temperature profiles for the bounding MSLB and LOCA. Figures 1 through 3 compare the Unit 2 RSG design basis event containment temperatures to the current EQ temperature envelope (Reference 15) and a "EQPro"

composite temperature profile (Reference 58). The "EQPro" profile has been used to evaluate the EQ equipment for an unrelated EQ Program update.

Unit 2 RSG Double-Ended Hot Leg Break LOCA

- The containment temperature exceeds the current AOR (Reference 3) MSLB/LOCA envelope between 6 seconds and 20 seconds.
- The containment design temperature of 351°F is not exceeded during a Unit 2 RSG double-ended hot leg break LOCA.
- The containment temperature does not exceed the EQ composite curve used for current EQ equipment qualification.

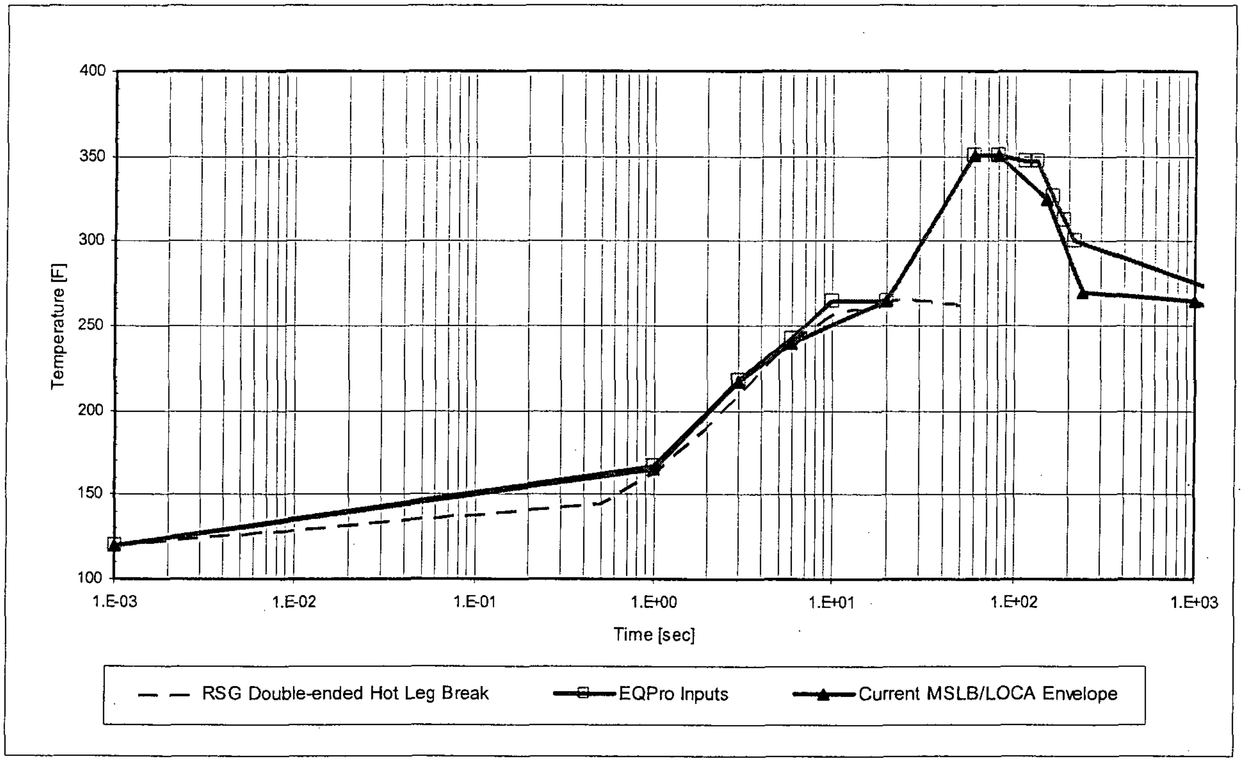

Figure 6.5-1: Unit 2 RSG Hot Leg Break LOCA Containment Temperature Profiles

Unit 2 RSG Double-Ended Pump Suction Break LOCA

- The containment temperature response during this event is bounded by the current composite MSLB/LOCA temperature envelope for the first 1000 seconds.
- The containment temperature exceeds the current MSLB/LOCA envelope between 1000 seconds and approximately 4×10^6 seconds.
- The containment design temperature of 351°F is not exceeded during a Unit 2 RSG double-ended pump suction break LOCA.
- The containment temperature does not exceed the EQ composite curve used for current EQ equipment qualification.

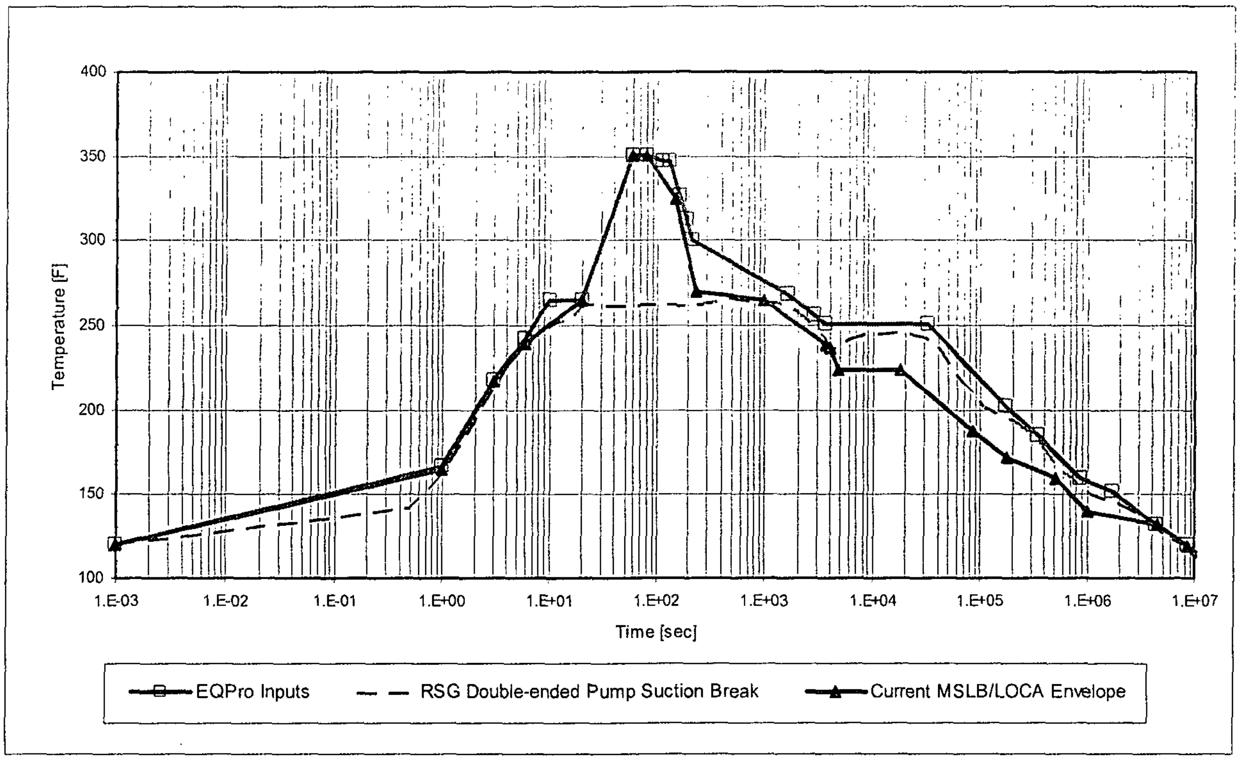

Figure 6.5-2: Unit 2 RSG Cold Leg Break LOCA Containment Temperature Profiles

Unit 2 RSG Main Steamline Breaks

- The containment temperature exceeds the current composite MSLB/LOCA temperature envelope from 5 to 20 seconds and 90 to 800 seconds.

- The containment peak temperature of 349.6°F for the Unit 2 RSG MSLB is bounded by the containment design temperature of 351°F.

- The containment temperature does not exceed the EQ composite curve used for current EQ equipment qualification except for the period of 6 to 20 seconds after the initiation of a design basis event. The brief duration and limited increase in the containment temperature is considered to have a negligible impact on EQ equipment in containment due to the limited heatup duration.

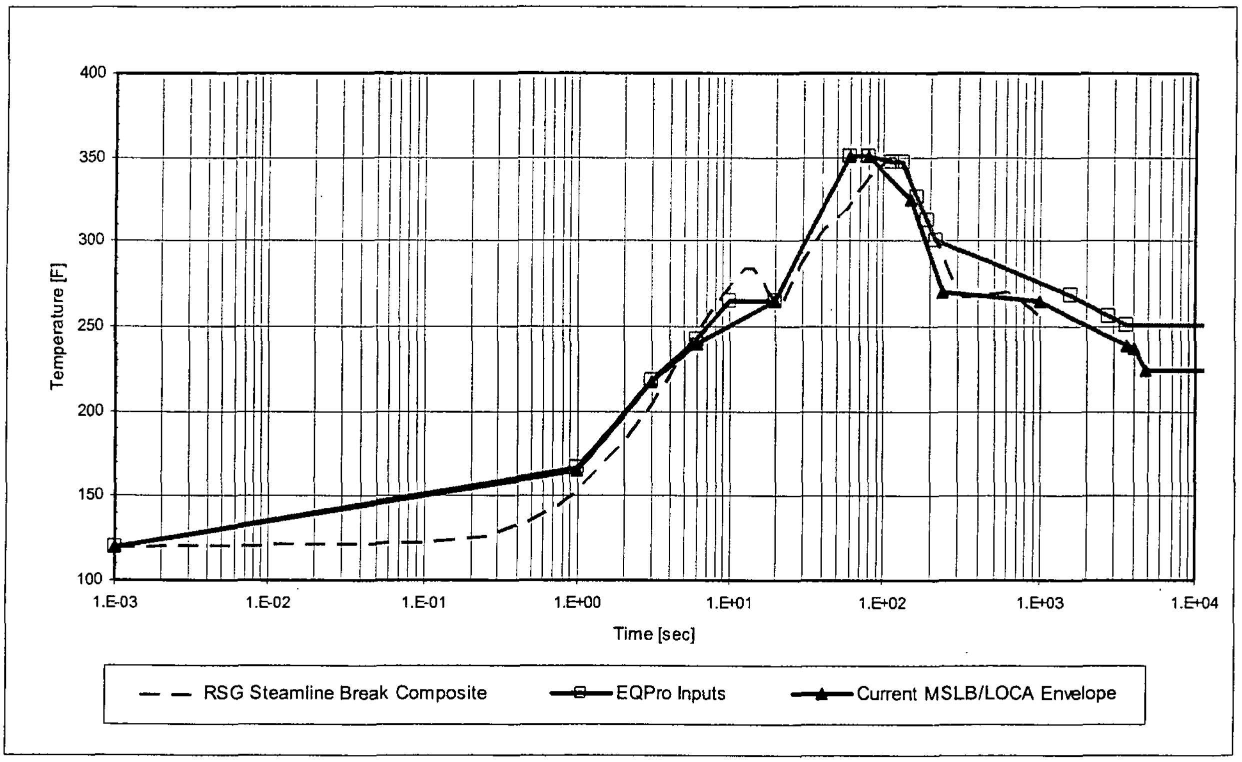

Figure 6.5-3: Unit 2 RSG MSLB Containment Temperature Profile

Conclusion

Relative to the current temperature profiles for current EQ analyses, the Unit 2 RSG containment transient analysis will produce a more severe containment temperature profile, although the design temperature of 351°F still bounds the peak containment temperature of 349.6°F.

A faster rate of containment temperature change occurs during a Unit 2 RSG MSLB during the period of 6 to 20 seconds following the initiation of a design basis event but this will not impact the environmental qualified safety related equipment due to the minimal change in the heat transfer to the EQ equipment that might occur over the short exposure duration of 14 seconds.

A review of the current Salem EQ analyses and subsequent engineering analysis (Reference 58) support the conclusion that the PAOT qualification is acceptable for the revised WCAP-16503 containment conditions. No EQ equipment will be impacted by the higher containment temperatures or pressures. There is no adverse impact of the revised Unit 1 or Unit 2 LOCA or MSLB containment analysis on the qualification of the EQ equipment within containment.

6.6. CFCU SW Piping Temperature Impact

The changes in the containment temperature versus time profile combined with planned changes in CFCU heat removal capacities will impact the expected maximum temperature of the service water in the CFCU SW return piping. Salem calculation S-C-CBV-MDC-1637 Section 5.2.1 (Reference 6) estimates that the current maximum CFCU outlet temperature is 221°F. The estimated maximum CFCU Service Water outlet temperature after implementation of the fixed resistance modification is 208.5°F, S-C-CBV-MDC-1637 Attachment I Table 2 (Reference 6). The CFCU Service Water piping analysis was performed at a fluid temperature of 221°F, Table 6.2-2.

Conclusion
The results of the WCAP-16503 Revision 3 containment response analyses are within the CFCU SW piping design capability.

6.7. Valve Pressure Locking/Thermal Binding Impact

The Salem valve Pressure Locking/Thermal Binding (PL/TB) analyses were documented in VTD 320802 (Reference 18). For valves inside containment, the analyses assumed a containment atmospheric temperature of 348.2°F as the maximum containment temperature for accidents based on Revision 1 of PSEG Calc S-C-ZZ-SDC-1419, "Salem Generating Station Environmental Design Criteria."

The only valves potentially impacted by the change in peak containment temperature of 349.6°F are 1(2)PR6, 1(2)PR7 and the SJ54 valves (Reference 18),. A review of PSBP 320802 indicates that there is no impact on the PR6 and PR7 valves, PORV block valves, as these valves do not have LOCA or MSLB safety function and that these valves are normally open. Similarly, the review of the impact on the SJ54 valves (Reference 18), shows that these valves are actuated by a Safety Injection Actuation Signal (SIAS) at the beginning of ECCS Injection and are open when containment temperatures peak. The containment temperature does not approach a peak value until 113 seconds into the MSLB transient or 485 seconds for a LOCA transient.

Pressure locking of a valve due to an ambient temperature increase can only occur if the valve is shut and the bonnet pressure increases due to ambient heating of trapped water. Thermal binding of a closed valve can only occur due to disc and seat expansion when exposed to high process fluid temperature differentials across the valve disc. In both cases, normal operation with a valve in the open position precludes pressure locking and thermal binding phenomenon.

It is noted that the use of the 348.2°F temperature value in VTD-320802 (Reference 18) is not consistent with the peak containment temperature of 349.6°F determined in WCAP-16503 but there is no impact to the plant as this change is only a documentation update. Salem document VTD 320802 (Reference 18) should be updated to reflect the updated slightly higher peak containment temperature.

Conclusion
WCAP-16503 Revision 3 containment response analyses has no impact on the PL/TB analysis other than requiring VTD 320802 to be updated to reflect the higher containment peak temperatures.

6.8. GL96-06 Impact

NRC Generic Letter 96-06 required evaluation of the CFCUs for potential waterhammer events following LOOP and LOOP/LOCA type events. The containment temperature and pressure conditions following the design basis events and the CFCU SW operating conditions (startup times, pressures, and flows) are a direct input to GL96-06 analyses. Salem's response to GL96-06 was to install two 15,000 gallon accumulators on the Service Water System piping headers. The function of the SW accumulators is to inject water into each Service Water header during a LOOP to ensure that the Service Water piping, particularly downstream of the CFCUs, are maintained in a single phase condition until the Service Water Pumps are restarted from an Emergency Diesel Generator. This SW System design feature ensures that waterhammer cannot occur as two-phase conditions are not allowed for develop. The SW Accumulator nitrogen gas cover pressure and water level in each accumulator is verified by Technical Specification surveillance requirements and are established to accommodate a minimum CFCU Service Water flow rate of 2550 gpm. The revised minimum CFCU Service Water flow rate of 1300 gpm (Reference 6) is reduced from 2550 gpm, so the current SW Accumulator process parameters are conservative as the SW accumulator injection flow rate during a LOOP exceeds the revised minimum CFCU flow requirements.

GL96-06 also required evaluation of piping and penetrations for potential thermal over-pressurizations during the accident events. Consequently, the impact of the increased containment temperature on isolated containment penetrations and piping is considered. The current Salem design basis calculations (References 26 through 29) were reviewed to establish the impact for both Salem units.

For Salem Unit 1, potentially impacted piping penetrations M22, M22A, M25, M25A, M27 and M45 were modified by DCPs 1EC-3718 and 1EC-3687 to add relief valves to ensure continued structural integrity. The relief valve set point and flow capacity are not affected by the increased temperatures. Therefore, Salem Unit 1 containment penetration/piping integrity is not affected by an increase in the containment temperature due to the reduction in the CFCU heat duty.

For Salem Unit 2, piping penetrations M22, M22A, M25, M25A, M27 and M45 are potentially impacted. Salem calculation S-2-MEE-1145 (Reference 28) evaluated penetrations M22, M25 and M25A. Penetrations M22 and M25A were protected by installing overpressure protection (DCPs 2EC-3605 and 2EE-0307) in the isolated piping sections.

The design basis analysis of Penetration M25 (Reference 28) assumes a LOCA containment temperature of 260°F and an average trapped water temperature of 126.9°F. Calculation S-2-ZZ-MEE-1145 (Reference 28) states that the calculated peak pressure in the isolated piping is approximately 2977 psia. WCAP-16503 Table A6.3-6 shows a bounding peak LOCA temperature of 265.9°F for a LOCA with a LOOP. A scoping calculation indicates that the change in the average trapped fluid temperature in Penetration M25 is small and the impact of thermal pressurization on penetration M25 peak pressure is expected to be small (less than 1 psia). Calculation S-2-ZZ-MEE-1145 (Reference 28) states that the peak pressure in penetration M25 will not exceed 3000 psig. Calculation S-2-ZZ-MEE-1145 (Reference 28) states that the maximum working pressure of the containment isolation valves is 3415 psig and the maximum allowable pressure of the affected piping is 6674 psig. Therefore, the existing Penetration M25 design is judged to be adequate to accommodate the slight increase in containment temperature identified in WCAP-16503 during a LBLOCA. Salem calculation S-2-ZZ-MEE-1145 should be updated to reflect the revised containment temperature profile.

Salem Unit 2 Penetrations M22A, M27 and M45 were evaluated in Reference 29, and are estimated to have a limiting pressure of 218 psig, 218 psig and 417 psig, respectively. The limiting pressures for these isolated piping runs located in containment are based on the design of the Containment Isolation Valve (CIV) air operator spring rates for 2WR80, 2WL13 and 2WL17. The CIV valves are pressurized under the plug seat and are spring shut. As the isolated water volume is heated from elevated containment temperatures, the pressure will increase until the upward force on the valve disk exceeds the spring closing force. The disk will move from the seat and provide a small leakage path to the downstream system piping. Leakage from isolated penetrations M22A, M27 and M45 will discharge to the Pressurizer Relief Tank, the CVCS Holdup Tank and the Waste Holding Tank, respectively. The increase in the containment temperatures, WCAP-16503 do not increase the calculated peak pressure in Salem calculation S-2-ZZ-MEE-1177 (Reference 29) due to the design of the piping and the valves adjacent to penetrations M22A, M27 and M45.

Conclusion
The GL96-06 analyses conclusions are not impacted by the WCAP-16503 Revision 3 analysis results for the plant changes addressed under this Engineering Evaluation. Salem calculation S-2-ZZ-MEE-1145 (Reference 28) should be updated to reflect the change in Salem containment temperature profile under LOCA conditions.

7. Reduction in Required CFCU Flows for Accident Conditions

The reanalysis of the containment temperature response for design basis accidents recovered significant margin with regard to the CFCU heat removal capacity. This allows the required CFCU flow under accident conditions to be reduced significantly. PSEG Nuclear intends to use this margin to support adoption of a single flow rate for both normal and accident conditions. This will allow PSEG Nuclear to modify the Salem Service Water (SW) System supply to the CFCUs to replace the active CFCU SW flow control design with a passive, fixed hydraulic resistance design. These modifications will simplify the SW System and eliminate numerous active components that require ongoing surveillance testing and maintenance as well as improve the operability of the Salem SW System.

The minimum required CFCU SW flow will be reduced from 2550 gpm to 1300 gpm which will satisfy the heat removal capability credited in the new containment analysis and ensure that flashing will not occur in the SW System. The 1300 gpm minimum flow requirement consists of a minimum delivered flow rate of 1250 gpm to the CFCU cooling coils and 50 gpm to the CFCU motor cooler. This reduction in minimum allowable SW flow is accompanied with the elimination of all the modulating control valves (elimination of the SW-57, and SW-65 valves; conversion of the SW223 to a block control valve) in each CFCU loop and the installation of several fixed diameter orifices for additional hydraulic resistance.

The SW System modification will be controlled within PSEG Nuclear's 10CFR50.59 Program and existing plant modification procedures.

7.1. Current System Description

Each Salem unit has five CFCUs inside the containment building to provide for normal and emergency cooling of the containment environment (Reference 50). The CFCUs cool the containment using fans which force containment air over finned coils, which are cooled by the SW System. For Salem, the CFCUs are required to operate during all postulated accidents to provide containment cooling and maintain containment pressures and temperatures within approved design criteria.

The current system configuration of the CFCU portion of the SW system is shown in Figure 7.1-1.

7.1.1. Containment Fan Cooler Units

Each CFCU is composed of two banks of six coils (twelve coils in total) (Reference 50). The coils are arranged and connected so that all twelve coils are in parallel on the tube (SW) side and the two banks of six coils are in series on the air side. The coils construction is:

Tube OD	0.625 in
Tube Wall Thickness	0.035 in
Tube Material	AL-6X
Tube Configuration	U-tubes
Tube Length	Approximately 19 feet

The CFCU's are located high in containment between elevations 130' and 145'. The SW piping from the CFCUs has an elevation of approximately 154' (Reference 50). For reference, grade is considered to be elevation 100'.

The CFCU fans are designed to operate at high speed for normal conditions and low speed for accident conditions. The change in fan speeds is necessary due to the change in the air density. The system design conditions for each mode are shown in Table 7.1-1.

Table 7.1-1: CFCU Design Conditions

Parameter	Normal Mode	Accident Mode
Fan Speed (RPM)	1200	600
Air Flow Rate (cfm) [5 CFCU/3 CFCU Operating]	110,000	39,000/40,000
Air Inlet/Outlet Temperature (°F)	120/93	271/260
Service Water Flow (gpm)	700-900	2,500-2,600
Service Water Inlet/Outlet Temperature (°F)	90/99	90/160
As-Built Coil Cooling Capacity (BTU/hr)	3,140,000	87,100,000

Each CFCU fan motor is controlled by two normal mode high-speed (Breakers 1 and 2) breakers and one accident mode low-speed (Breaker 3) breaker. These three breakers have contactors that provide a control signal to the SW control valve (SW223) for each CFCU.

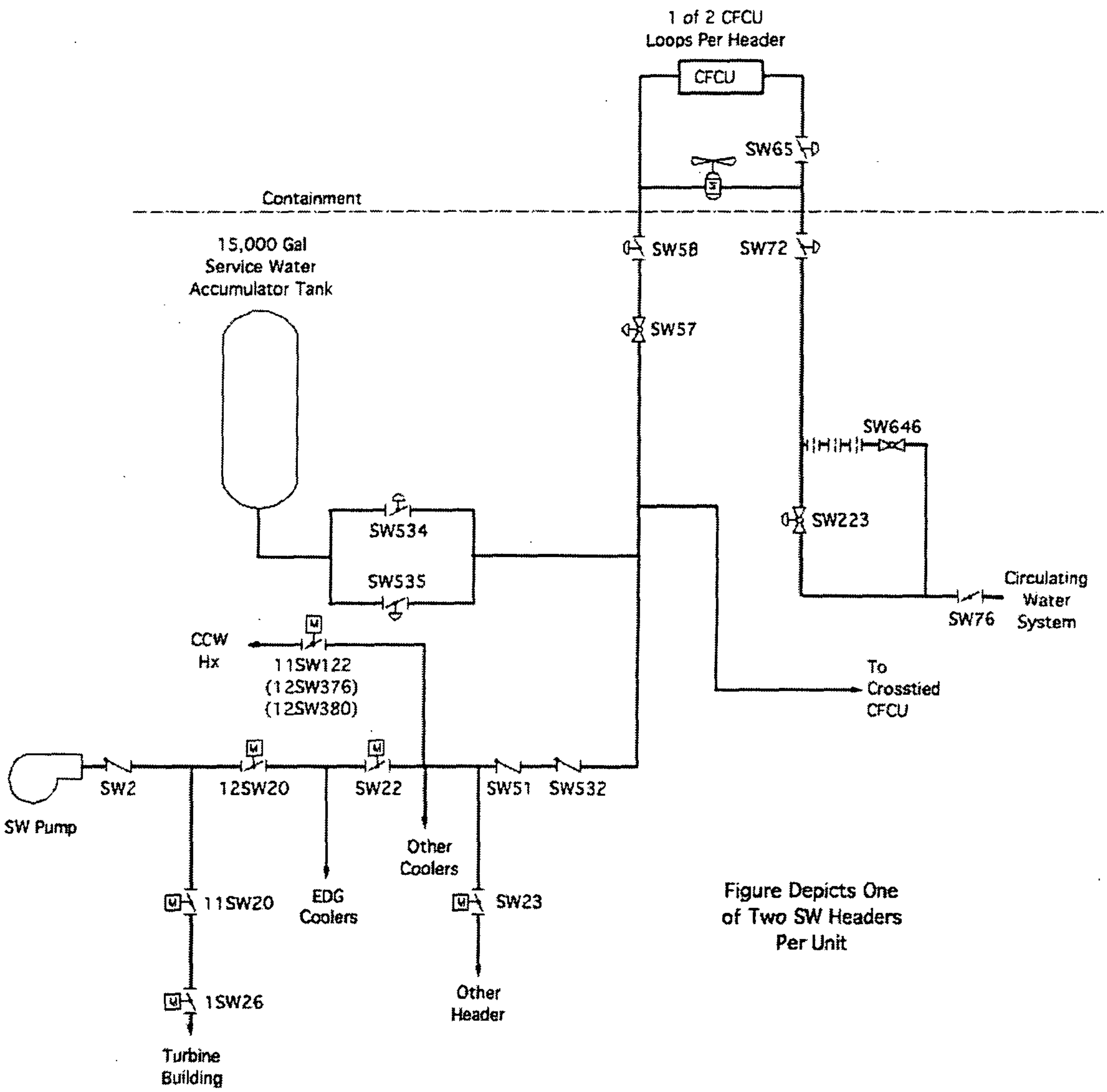

Figure 7.1-1: Current CFCU Service Water System

7.1.2. Safeguards Equipment Control System

In the event of a LOCA, the Safeguards Equipment Control (SEC) System provides a signal to change the CFCU SW control system from the normal operating mode (high fan speed, low SW flow) to the accident operating mode (low fan speed, high SW flow). This CBV/SW Systems realignment, in conjunction with the Containment Spray Pumps, is necessary to ensure that containment pressure and temperature will not exceed its design parameters of 47 psig and 351°F.

1. For the case of a LOCA Only (SEC Mode I), the SEC will initially trip open CFCU Breakers 1 and 2 while auto closing Breaker 3 approximately 20 seconds (Reference 50) after event initiation, for each of the CFCU fans.

2. For the case of a LOOP Only (SEC Mode II), the CFCU fans must be manually restarted by the operators as EDG loading permits (Reference 50). A control signal is initiated to shut each CFCU SW outlet valve (SW223) to secure CFCU SW flow.

3. For the case of a LOOP coincident with a LOCA (SEC Mode III), Breakers 1 and 2 will automatically open on an Undervoltage trip and Breaker 3 will auto close approximately 18 to 22 seconds after the EDG output breaker closes (Reference 50).

7.1.3. CFCU Service Water Pressure Control

Under normal conditions, the SW57 pressure control valve modulates the CFCU tubeside backpressure via a two mode controller that receives a process pressure signal from just upstream of SW223 (the CFCU flow control valve). The pressure set point for SW57 is approximately 50 psig (Reference 50).

Under emergency conditions, the SW57 pressure control signal is bypassed when the CFCU fan shifts to low speed by energizing a solenoid valve, which allows SW57 to be fully open (Reference 50). The SW57 valve operator is a spring open design

7.1.4. CFCU Service Water Flow Control

Under normal conditions, the SW223 flow control valve modulates CFCU Service Water flow via a two-mode controller that receives a process flow signal from the flow element upstream of the associated CFCU. The controller has two set points—a normal-mode flow setpoint of 700 gpm and an accident mode flow set point of 2650 gpm—which are supplied to the SW223 valve operator via a solenoid valve and two set point air regulators. The control signal is only supplied to the SW223 operator when the associated CFCU fan is operating (Reference 50).

An additional flow control valve, SW65, is installed between the CFCU coil return and the CFCU motor cooler return piping to ensure that the CFCU Motor Cooler receives sufficient cooling water by adding hydraulic resistance to the CFCU coil flow path. SW65 is positioned to about 30 Percent Open during normal-mode CFCU operation and is positioned to 100 Percent Open during accident mode operation (Reference 50).

Individual CFCU SW piping Containment Isolation Valves are located in the supply line (SW58) and the return line (SW72) adjacent and outside of the Containment Building. These valves are normally unisolated under all operating modes. These block valves are controlled by manual push-button located in the Main Control Room and are either fully open or fully closed (Reference 50).

Nitrogen charged water accumulators equipped with fast acting isolation valves were installed in 1997 (Reference 50) to ensure that the CFCU piping was maintained in a water solid condition during the limiting system transient condition of a Loss-of-Offsite Power (LOOP) with a limiting single active failure. This SW system modification formed part of the basis for Salem's GL 96-06 response (Reference 50). Under a LOOP condition, bus under-voltage relays actuate the accumulator tank isolation valves to open and float the SW system header on the accumulator tanks, which are sized to have adequate capacity to allow sufficient time for automatic restoration of the SW Pumps.

7.2. Service Water System Modification

The modified SW System design includes the features identified below. The as-modified system, as currently envisioned, is shown in Figure 7.2-1.

- A single minimum SW flowrate of 1300 gpm supplied to each CFCU (Cooling Coils and associated Motor Cooler).

  The reduction in SW flow to the CFCUs is consistent with the reduced heat removal assumptions of WCAP-16503 (Reference 1) shown in **Table 7.2-1**~~Table 7.2-1~~. The minimum CFCU Service Water flow rate will be increased in the field to accommodate other considerations such as GL 89-13 requirements, tube plugging allowances, and bio-fouling trending margins.

- A combination of a fixed position throttle valve (modified SW223) and restriction orifices to set the total resistance through the CFCU loops.

  The CFCU Service Water line hydraulic resistance will be accomplished by a combination of fixed diameter orifices plates (RO-1/2/3/4 in **Figure 7.2-1**~~Figure 7.2-1~~), with a single throttle valve (modified SW223) for final flow balancing. The CFCU flow path will be converted to a fixed-hydraulic resistance by removing the current modulating control valve

(SW223) control circuitry and equipment and converting the SW223 valve to a block throttling valve and adding four fixed diameter orifice plates to each CFCU line. The SW223 valves will be converted to throttling block valves with the maximum valve position fixed by mechanical limit stops. Main Control Room remote operating capability will be retained.

Note that the SW57 and SW65 control valves will be eliminated and replaced with spool pieces as part of the modifications.

- A means of mitigating silt and sediment buildup in the CFCU tubes.

  Accomplished by manipulating the Service Pump alignment to increase CFCU tube velocities.

- Retain the existing SW Accumulator Tanks, SWE125 and SWE127.

  The tanks will be retained in the modified system to prevent waterhammer under LOOP conditions.

The results of the containment analysis show that the reduction in CFCU heat removal capacity required to implement these improvements in Service Water flow control scheme for the CFCUs can be accommodated. By utilizing a lower accident heat removal capacity for the CFCUs, Table 7.2-1, than is assumed by the current AOR (Reference 3), the minimum accident Service Water flow can be significantly reduced. A single SW flow rate allows for the elimination of the complicated and maintenance prone SW57 pressure control valves and the SW223 flow controllers. Increasing the normal SW flow rate from 700 gpm to a minimum of 1300 gpm also has the additional advantage of improving containment cooling for operations during the summer months.

The minimum Technical Specification CFCU SW flow rate (Reference 4) to the CFCUs during normal and accident operation is 1300 gpm (CFCU Coils – 1250 gpm and CFCU Motor Cooler – 50 gpm). The minimum CFCU SW flow of 1300 gpm incorporates margin for CFCU fouling (up from the present value of 0.0030 to 0.0035 hr-°F-ft^2/Btu), tube plugging and additional SW system flow margin to accommodate for adverse biofouling trending for the remainder of the Service Water System cooled components.

An advantage of a single CFCU SW flow rate design is that higher normal flow velocities can be achieved by shifting Service Water Pump alignment which will minimize sediment deposition, microbial induced corrosion (MIC) as well as general corrosion while simplifying the operator maintenance actions.

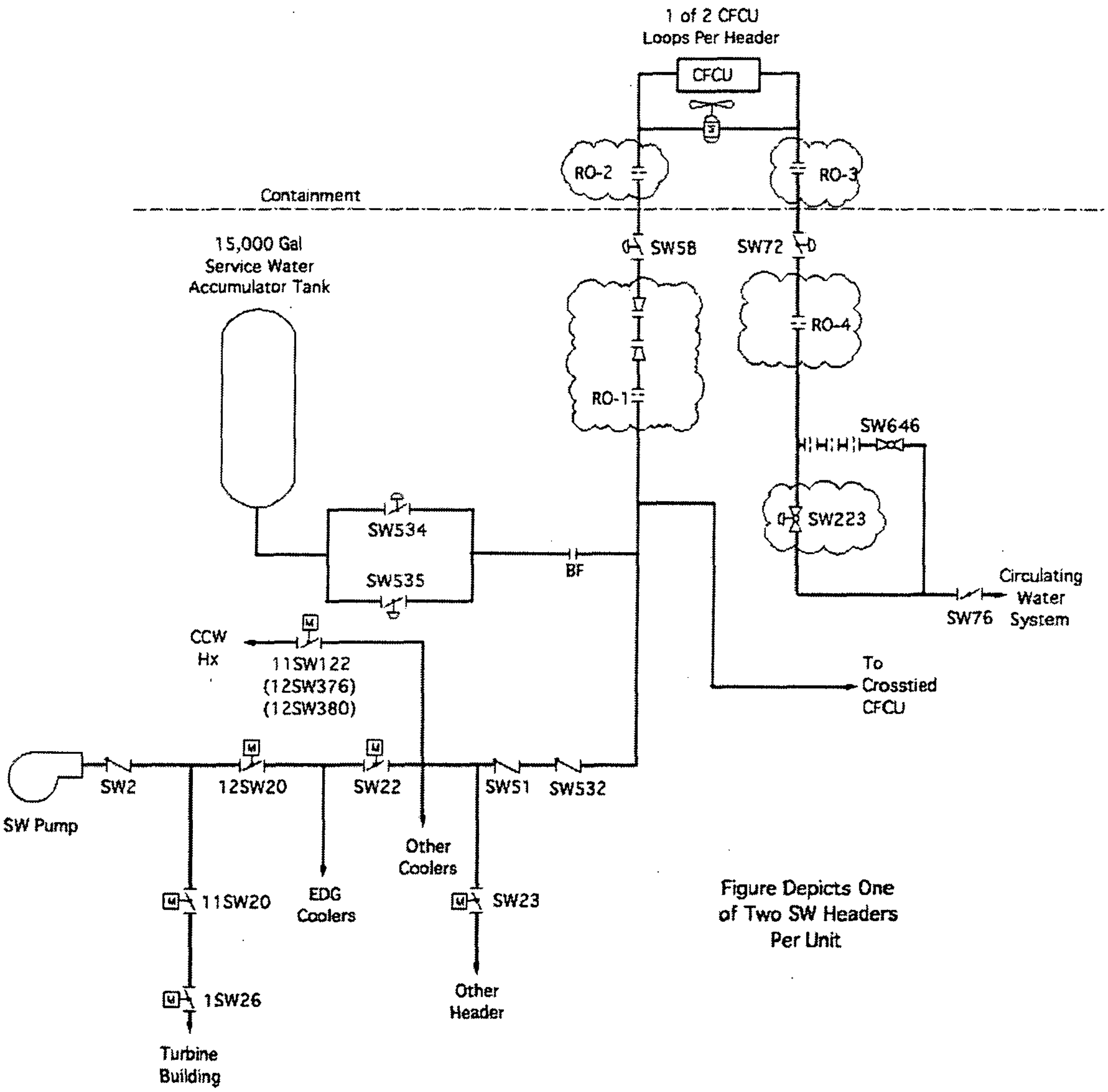

Figure 7.2-1: Modified CFCU Service Water System

Table 7.2-1: Revised CFCU Heat Removal Rates

Containment Temperature (°F)	Heat Removal Per CFCU (BTU/sec)
105	432.4
120	1080.5
140	2132.5
160	3321.7
180	4605.9
200	5904.3
220	7211.3
240	8471.0
260	9750.4
271	10441.7
280	11000.1
Reference 47, Attachment 1-A	

7.3. Evaluation of Acceptability of Reduced CFCU Flow Rate

In order to support this SW System design simplification, PSEG Nuclear had Westinghouse reanalyze the Salem containment temperature response, assuming a reduced CFCU heat removal rate (Reference 47) relative to the AOR, WCAP 13898 (Reference 3). The assumed CFCU heat removal capacity is shown in Table 7.2-1 (Reference 47).

Assumptions that are critical to the estimated CFCU thermal performance are SW supply temperature, maximum tube fouling thermal resistance, and SW flow rate. The assumed SW supply temperature of 93°F is conservative and provides 3°F margin to the maximum Ultimate Heat Sink temperature of 90°F (Reference 6). The assumed heat transfer surface fouling thermal resistance of 0.0035 hr-°F-ft^2/BTU is greater than the CFCU design thermal fouling resistance of 0.0030 hr-°F-ft^2/BTU (Reference 6). The minimum Service Water flow to the CFCU cooling coils is assumed to be 1250 gpm, which is conservative as the required flow to satisfy the minimum analytical CFCU heat removal capacity of 37.6 MBTU/hr at a containment temperature of 271°F is 930 gpm (Reference 6).

Table 7.3-1: Minimum CFCU Thermal Performance

Parameter	Estimated Value
LOCA Containment Air Temperature	265.9°F
Containment Relative Humidity	100%
Containment Pressure	58.2 psia
CFCU Coil Service Water Flow Rate	1250 gpm
CFCU Service Water Supply Temperature	93°F
CFCU Air Flow Rate	40,000 CFM
CFCU Fouling Factor	0.0035 hr-°F-ft^2/BTU
CFCU Heat Duty	44.0E6 BTU/hr

An additional consideration in establishing a minimum CFCU SW flow is maintaining the downstream piping in a water solid condition under all possible plant operating conditions. As previously discussed, PSEG Nuclear modified the Salem SW System in 1997 to include accumulators, whose function is to maintain the SW piping in a water solid condition during a LOOP or LOOP/LOCA transient prior to the SW pumps restarting. This portion of the SW System is not being modified. Following the restart of the SW pumps, and for other SW transient or steady state conditions that are not coincident with a LOOP transient and that result in heat input to the CFCUs, such as a LOCA with offsite power, the SW piping could be exposed to two phase flow due to inadequate margin to local saturation conditions.

Past CFCU thermal analyses, have conservatively assumed that the limiting set of operating conditions would be a failure of the CFCU high speed breaker to open (PR#970122069) following an SEC MODE I or III signal. This scenario is very unlikely since the CFCU fan would most likely trip on over-current due to the high density and moisture in the containment air during an accident. Nevertheless, it has historically been used as the basis for determining the maximum CFCU outlet temperature (including an assumed zero fouling factor) as it results in the highest saturation pressure in the SW return piping. The containment air side of the CFCU would operate under containment accident atmospheric conditions but with normal operating SW and containment air flow rates. The SW outlet temperature corresponding to the above conditions is 208.5°F (Reference 6). However, this particular single-failure scenario is not limiting from the standpoint of saturation margin as it does not result in the minimum SW return piping static pressure.

The SW system alignment which results in minimum static pressure is the limiting single failure scenario of a failure of an EDG where only two SW pumps operate with three CFCUs (all assumed to be at zero fouling). Salem Calculation S-C-CBV-MDC-1637 Addendum 1 (Reference 6) analyzes this system operating scenario and concludes that a minimum of CFCU coil Service Water flow of 1250 gpm and CFCU Motor Cooler flow of 50 gpm are sufficient to maintain the SW piping downstream of the CFCUs in a single phase condition. It also shows that the maximum CFCU outlet temperature is 204.9°F, assuming the operating conditions identified in Table 7.3-2. The minimum static pressures at three locations downstream of the CFCU are shown in Table 7.3-3. The minimum saturation margin is 0.1 psig, which occurs downstream of SW-223 in the CFCU return header (outside of containment) and is acceptable at the minimum Technical Specification flow to prevent two-phase flow conditions from developing in the CFCU Service Water return piping. The analysis is performed at the containment atmospheric conditions associated with the LOCA analysis in order to maximize the energy transfer rate into the CFCU tubeside water. Under LOCA conditions, the CFCU outside heat transfer surfaces will be in a condensing heat transfer mode which has significantly higher film coefficients and results in higher overall CFCU heat duty than for the MSLB accident conditions.

Table 7.3-2: Maximum CFCU Service Water Outlet Temperature Conditions

LOCA Parameter	Estimated Value
Containment Temperature	265.9°F
Containment Relative Humidity	100%
Containment Pressure at 265.9°F	58.2 psia
CFCU Coil Service Water Flow Rate	1250 gpm
CFCU Service Water Supply Temperature	93°F
CBV Air Flow Rate	40,000 CFM
CFCU Fouling Factor	0.0000 hr-°F-ft^2/BTU
CFCU Tubeside Outlet Temperature	204.9°F

Table 7.3-3: Minimum CFCU Service Water Return Subcooling Margin

Location	Node	Pressure (psia)	Temperature (°F)	Saturation Pressure (psia)	Margin (psia)
21 CFCU Outlet	93C	27.8	204.9	12.7	15.1
21 SW-223 Outlet	103	14.3	202.4*	12.1	2.2
21 CFCU Return Header	104A	12.2	202.4	12.1	0.1
24" SW Return Header	86	11.5	181.4**	7.8	3.7

Notes:

* Includes the effect of CFCU Coil and CFCU Motor Cooler outlet flow mixing.

** Includes the effect of multiple Service Water component outlet flow mixing.

Source: Reference 6.

7.4. Impact on Service Water System Failure Modes

In the current Salem SW System design, the following valves in the CFCU loops change state during accident conditions.

- SW57 repositions to full open rather than control pressure.
- SW65 repositions to full open rather than modulate to effect the flow split between the CFCU and the associated motor cooler.
- SW223 modulates to the accident CFCU flow rate rather than the normal flow rate.

The SW System Failure Modes and Effects Analysis (FMEA) (Reference 49), documents the postulated failure modes during post accident cooling. The only changes to the SW System FMEA are the elimination of the potential failures of SW57, SW65 and the loss of AC control power which impacts the modulating function of SW223. All other SW System failure modes are unaffected by this modification.

The deletion of active control valves SW57 and SW65 results in elimination of two of the currently analyzed SW System failure modes. The current failure modes of the SW57 and SW65 valves are the potential failure to reposition to full open on an initiating control signal. The deletion of SW57 and SW65 from the Salem Service Water System results in the elimination of the associated SW System failure modes.

The conversion of the SW223 valves to a non-modulating fixed position design will eliminate the applicable Instrument Loops (FA3160/3665/3176/3172/3169). The deletion of these Instrument Loops results in the elimination of the SW223 failing open failure mode during a LOOP with a concurrent Loss of AC Control Power. No additional active or passive design features are being added to the CFCU portion of the SW System.

7.5. Conclusion

The discussion above provides the basis for the conclusion that a minimum CFCU flow of 1300 gpm (1250 gpm for the CFCU + 50 gpm for the motor cooler) is adequate to meet the CFCU heat removal assumptions in WCAP-16503 (Reference 1) and prevent flashing in the SW system with maximum heat transfer conditions. Further, the modifications eliminate several of the limiting system failure modes.

8. Identification of Minimum Surveillance Testing

Minimum required surveillance testing to support the evaluations described in this EE for crediting the SGFP trip and FIV closure in the containment analyses include the following:

- BF-13 Feedwater Isolation Valves
  - Verification of SI signal for BF13 FIV actuation (See Section 5.2 and References 32 through 33)
  - Verification of signal delay and stroke time delays up to closure of BF13 FIVs. (See Section 5.2)
- Steam Generator Feed Pumps
  - Verification of SI signal actuation of SGFP trip (See Section 5.3 and References 32 through 33)
  - Verification of signal and mechanical delays up to closure of MS43 and RS15 SGFP Stop Valves. (See Section 5.3)

Although existing surveillance procedures exist for verification of BF13 FIV logic and delays, Technical Specification changes and new surveillance procedures are required to support this evaluation for SGFP trip as discussed in Section 5.3.

Minimum Required Surveillance Testing to support the evaluations described in this EE for reduced CFCU heat removal assumed in the containment analyses include the following:

- Revision of Technical Specification surveillance requirement 4.6.2.3.b.3 (See Section 7)

- Revision of Technical Specification surveillance requirement 4.6.2.3.c.2 (See Section 7)
- Revision of CFCU Surveillance Procedures S1(2).OP.ST.CBV-0003 (References 54 and 55).

9. Evaluation Results

Based on the above evaluation, the revised containment response per WCAP-16503 Revision 3 is consistent with the plant design basis and has no adverse impacts on the plant systems, programs and analyses. Changes to the Technical Specifications and Surveillance Testing procedures as described in Section 7 are required to allow periodic verification of SGFP trip parameters used in the revised containment response analysis and the revised minimum Technical Specification surveillance CFCU cooling water flow.

Other than the SI signal process delay, no current plant procedures exist to routinely verify the time delays associated with the Solenoid Trip Valve and Turbine Stop Valves closing stroke. An open item associated with acceptance of the LCR is establishment of routine surveillance testing to verify the SGFP trip circuit signal and mechanical time delays consistent with other SI signal testing requirements (i.e., once every cycle or 18 months). This testing needs to demonstrate the total time from initiation of SI signal to closure of the MS43 and RS15 stop valves are completed within 7 seconds to ensure that the logic and time delays used in the WCAP remain bounding.

The SGFP coastdown time of 7 seconds is based on assumptions used at other similar Westinghouse plants to justify crediting non-safety feedwater equipment use in mitigating a MSLB with a flow control valve failure. Verification of the SGFP coastdown time assumption is documented in Technical Evaluation 60067092-20.

A scoping evaluation of the impact of the slight increase in containment peak temperature from WCAP-16503 during a LOCA indicates that the thermal pressurization of Penetration M25 is likely to be minimal and within the existing structural capability of the current design. PSEG should update calculation S-2-ZZ-MEE-1145 (Reference 28) to verify this result (Reference SAP Operation 80089131-0007).

A minimum CFCU flow of 1300 gpm (1250 gpm for the CFCU + 50 gpm for the motor cooler) is adequate to meet the CFCU heat removal assumptions in WCAP-16503 (Reference 1) and prevent flashing in the SW system with maximum heat transfer conditions. Conversion of the CFCU loops to a fixed flow resistance simplifies the system and eliminates several of the limiting system failure modes.

10. References

1. PSEG Vendor Technical Document VTD-900401, WCAP-16503-NP, "Salem Unit 1 and Unit 2 Containment Response to LOCA and MSLB for Containment Fan Cooler Unit Margin Recovery Project," Revision 3, February 2007.

2. Salem UFSAR, Rev. 21.

3. Westinghouse Project Letter, PSEBO-97-022, "Safety Evaluation for Revised Fan Cooler Delay Time (SECL-96-178, Revision 2)", dated September 2, 1997.

4. Licensing Change Request (LCR) S06-010.

5. Technical Specifications thru Amendment 266 (for Unit 1) and Amendment 253 (Unit 2).

6. Salem Calculation S-C-CBV-MDC-1637, Revision 3.

7. PSEG Document DE-CB.CN-0015, "Configuration Baseline Document for Steam Generator Feedwater and Condensate System" Revision 5

8. PSEG Document VTD 305512, SG Feedwater Pump Instruction Manual, Revision 16.

9. PSEG Nuclear Logic Diagrams:
   - 231440 Sheet 1 Rev. 19,
   - 231440 Sheet 2 Rev. 20,
   - 231445 Sheet 1 Rev. 18,
   - 231445 Sheet 2 Rev. 18,
   - 221062 Rev. 8,
   - 239904 Rev. 4,
   - 239907 Rev. 4.

10. PSEG Nuclear Schematic Diagrams:
    - 203327 Rev. 35,
    - 203337 Sheet 1 Rev. 33
    - 203337 Sheet 2 Rev. 33
    - 203364 Rev. 12,
    - 203365 Rev. 14.

11. PSEG Salem Surveillance Procedure S1.OP-ST.MS-0002(Q) "In-Service Testing Main Steam and Feedwater Valves," Revision 10 [and Unit 2 Procedure S2.OP-ST.MS-0002].

12. PSEG Salem Surveillance Procedure S1.RA-ST.MS-0002(Q) "In-Service Testing Main Steam and Main Feedwater Valves Acceptance Criteria," Revision 9 [and Unit 2 Procedure S2.RA-ST.MS-0002].

13. PSEG Calculation S-1-CN-MDC-0881 Sheet 001, MOV Capability Assessment for 11BF13-MTRY," Revision 0 dated 3/12/95, includes reference to Nuclear Fuels Calculation D01.6-797 [Roll=06510, Frame=1797]

14. EPRI TR-103237-R2, *EPRI MOV Performance Prediction Program Topical Report – Revision 2*, dated April, 1997.

15. PSEG Calc S-C-ZZ-SDC-1419, "Salem Generating Station Environmental Design Criteria", Revision 3.

16. KCI Calculation No. 630-002-DC3, Rev. 0, "Updated Containment Temperature and Pressure Inputs for Environmental Qualification in Preparation for Steam Generator Replacement at Salem Generating Station," dated 10/13/2006.

17. KCI Letter KCI-06-05, dated January 11,2006, transmitting Calculation 630-002-DC2, Rev. 0, "EQ Assessment of Revised LOCA Profile Due to Replacement Steam Generator at Salem Station" (VTD 900494).

18. PSEG Vendor Document 320802, Revision 1 [Corresponds to MPR Report MPR-1693, "Evaluation of Salem Valves for Pressure Locking and Thermal Binding,' Revision 1 (dated June 1, 1997)].

19. Salem Calculation S-C-ZZ-MDC-1945, Revision 0.

20. Salem Calculation S-C-ZZ-MEE-1797, Revision 0.

21. Kays and London, Compact Heat Exchangers, pp. 27-29

22. Salem VTD-304209, Westinghouse Precautions, Limitations and Setpoints, - Auxiliary Coolant System, Revision 35, dated 2/15/06, pg 61.

23. Salem Calculation S-C-MEE-0784 Revision 3.

24. Salem Calculation S-C-MEE-0780 Revision 1.

25. Email from H. Trenka (PSEG) to A. Johnson (Salem Design Engineering), "Changes in Accident Modeling Assumptions", dated 12/10/05.

26. Salem Calculation S-1-ZZ-MEE-1231, Revision 1.

27. Salem Calculation S-1-ZZ-MEE-1173, Revision 2.

28. Salem Calculation S-2-ZZ-MEE-1145, Revision 3.

29. Salem Calculation S-2-ZZ-MEE-1177, Revision 1.

30. MPR Calculation 0108-0342-JFL-01 Revision 0. [included as Attachment 1]

31. E-mail From PGE (J. Nelson) to PSEG (J. Rowey), Subject: "RE: Salem Looking for DCPP MFWPP design info" dated May 11, 2006. [included as Attachment 2]

32. PSEG Procedure S1(2).OP-ST.SSP-0011(Q), Revision 11, Engineered Safety Features Response Time Testing, dated 1/5/05.

33. PSEG Procedure S1(2).OP-SO.CN-0002(Q), Revision 19, Steam Generator Feed Pump Operation, dated 11/6/05

34. Pacific Gas and Electric Company Letter DCL-98-109, License Amendment Request 98-05, dated 8/10/98

35. Indian Point Unit 3 UFSAR Section 14.2.5.6, "Containment Peak Pressure for a Postulated Steam Line Break".

36. Indian Point Unit 3 Technical Specification Section 3.7.3.2.

37. NRC Letter to PGE, "Diablo Canyon Nuclear Power Plant, Units 1 and 2 – Issuance of Amendment Re: Main Feedwater System (TAC Nos. MA3407 and MA3408", dated 2/22/00.

38. Westinghouse Letter PSE-06-73 – "PSEG Nuclear Salem Unit 2 – Transmittal of Calculation Note (CN-CRA-06-35)", dated 8/7/06

39. Westinghouse Calculation Note CN-CRA-03-49 Revision 0, "Salem Steamline Break Mass/Energy Release and Containment Response Analysis for CFCU Enhancement Program", dated 2/4/04.

40. PSEG Letter EA-CFCU-03-004, "PSEG Nuclear Response to Westinghouse Input Request for CFCU Project Containment Mass and Energy Release Analyses", dated 7/10/03.

41. PSEG Letter EA-CFCU-03-005, "Additional Clarification for CFCU Project Containment Analyses Input Parameters", dated 10/20/03.

42. PSEG Letter SGR-06-0064 Revision 1, "Evaluation of Changes to Salem Containment Heat Sinks and Free Volume", dated 8/21/06.

43. Westinghouse Calculation Note CN-CRA-06-063 Revision 0, "Analysis of Increased Paint Thickness on Containment Heat Sinks for Salem Steamline Break Inside Containment", dated 10/16/06.

44. PSEG Nuclear calculation PS-PSE-0727, "Salem Feedwater Flows For Steamline Break Analyses," dated 12/28/93.

45. PSEG Letter LTR-SEE-03-150, "Salem Units 1 and 2 CFCU/Service Water Enhancement Project," dated 7/22/2003.

46. S-C-ZZ-MDC-1987 Revision 1.

47. PSEG Letter SDE-2007-0001, "Reconfirmed Input Parameters for Additional Clarification for CFCU Containment Analysis Input Parameters", dated 1/5/07.

48. PSEG Calculation 6SO-0791-004, Revision 4, "Evaluation of Containment Structures for Latest Temperature Loads, dated August 1, 1997.

49. PSEG Calculation S-C-SW-MEE-1162, Revision 4, "Service Water System Failure Modes and Effects Analysis", dated 10/1/01.

50. PSEG Calculation S-C-SW-MEE-1138, Revision 1, "Salem Generic Letter 96-06 Evaluation", dated 5/6/98.

51. PSEG Calculation 6SO-1800 Revision 1A.

52. PSEG Calculation 6SO-2027 Revision 0.

53. PSEG Calculation 6SO-2028 Revision 1A.

54. PSEG Procedure S1.OP-ST.CBV-0003 Revision 13, "Containment Cooling Systems", dated 5/11/01.

55. PSEG Procedure S2.OP-ST.CBV-0003 Revision 14, "Containment Cooling Systems", dated 12/18/02.

56. Memorandum, A. C. Thadani, US NRC Office of Nuclear Reactor Regulatory Research, to S. J. Collins, US NRC Office of Nuclear Reactor Regulation, dated 02/24/2000 (Accession No. ML003701987).

57. Nuclear Regulatory Commission Regulatory Guide 1.89, "Qualification of Class 1E Equipment for Nuclear Power Plants."

58. Salem Document - "Evaluation of WCAP-16503-NP Revision 3 RSG Containment Temperature and Pressure Inputs Relative to the Environmental Qualification Program for Salem Generating Station" (SAP Number 8009131-0005).

11. Effects on Other Technical Documents

- UFSAR Section 15.4.8.2.2 "Method of Analysis, Single Failure Assumptions, Feedwater Flow," – Revisions to clarify analysis credit for feedwater flow reduction due to SGFP trip and FIV closure.

- UFSAR Section 6.2.2 "Containment Fan Cooling System," – Revision to clarify analysis assumption for reduced CFCU heat removal capacity.

- EQ Program Documents, Including Calculation S-C-ZZ-SDC-1419 (EDC) – Revisions to incorporate new EQ profiles based on results of WCAP-16503 Revision 3 containment response analyses.

- Calculation S-2-ZZ-MEE-1145 – Revision to incorporate WCAP-16503 Revision 3 temperature profile revisions.

- SGFP Trip Surveillance Testing Procedures and bases documents – Revised to incorporate reference for basis of time delay testing criteria (defined by this EE)

- VTD 320802 requires a disposition to document the acceptability of the increase in peak containment temperature.

- Calculation S-C-SW-MEE-1162 – Revision to incorporate Design Changes DCPs 800088611 (U1) and 80089131 (U2).

- Calculation S-C-SW-MDC-1637 – Revision to incorporate Design Changes DCPs 800088611 (U1) and 80089131 (U2).

- CFCU Service Water Flow Surveillance Testing Procedures S1(2).OP.ST.CBV-0003 to incorporate the reduced CFCU Service Water flow rates.

12. Attachments

Attachment 1: MPR Calculation 0108-0342-JFL-01 Revision 0.

Attachment 2: E-mail From PGE (J. Nelson) to PSEG (J. Rowey), Subject= "RE: Salem Looking for DCPP MFWPP design info" dated May 11, 2006.

13. Signatures

Preparers: Jeff Lundy, MPR Date: 2/19/07

Reviewer/Checker: Matthew C. Frey, MPR Date: 2/19/07

Independent Design Verifier: James L. Hibbard, MPR Date: 2-19-07

Contractor Approver: John W. Simons, MPR Date: ~~2-19-07~~ ~~2-20-07~~ 3-1-07 JWS

Approved by: ~~KEK 2/21/07~~ KEK 3/1/07 Alan Johnson Date: ~~2/21/07~~ 3/1/07 AJ

Attachment 1
MPR Calculation 0108-0342-JFL-01 Revision 0
Analysis of CCW Supply Temperature During LOCA Recirculation