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Safety Evaluation of Ginna SG Replacement

VENDOR'S DOCUMENT REVIEW

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1. PURPOSE

The purpose of this document is to evaluate the accident analyses that support the Ginna updated final safety analysis report (UFSAR) and verify that the analyses remain bounding or that all acceptance criteria continue to be met following steam generator replacement with BWI steam generators. For those cases that cannot be shown to meet the acceptance criteria using a straight forward evaluation, confirmatory computer analysis is recommended.

2. BACKGROUND

The R. E. Ginna Nuclear Power Plant is a 1520 MWt, Westinghouse-designed pressurized water reactor. The plant has two loops that each contain a U-tube recirculating steam generator with 3260 tubes. As a result of tube degradation in the existing steam generators, Rochester Gas & Electric Company is replacing the existing steam generators with two BWI steam generators. A comparison of steam generators is given in Table 2-1. In the remainder of this document, the acronym OSG refers to the original steam generator and RSG refers to the replacement steam generators.

Table 2-1. GINNA Steam Generator Parameters

Parameter	Original	Ref	Replacement	Ref
Steam Generator Type	Feed-Ring W Series 44		Feed-Ring	
Heat Load/SG, Btu/hr	2.602E+9	1	2.602E+9	2
Steam Flow/SG, lb/hr	3.29E+6	1	3.26E+6	2
Number of Tubes/SG	3260	1	4765	2
Tube O.D., in	0.875	1	0.750	2
Tube I.D., in	0.775	*	0.664	*
Tube Thickness, in	0.05	1	0.043	2
Secondary Heat Transfer Area, ft^2	44430	1	54001	2
Primary Heat Transfer Area, ft^2	39406	1	47809	2
Overall Tube Bundle Height, ft	31.20	1	30.427	2
Primary Side Nozzle-to-Nozzle ΔP, psi Primary Flow/SG, lb/hr				
0% Tube Plugging	33.54 @ 34.60 Mlb/hr		31.01 @ 34.95 Mlb/hr	
10% Tube Plugging	38.16 @ 33.93 Mlb/hr	6	35.82 @ 34.28 Mlb/hr	6
15% Tube Plugging	40.88 @ 33.52 Mlb/hr		38.72 @ 33.85 Mlb/hr	
20% Tube Plugging	43.98 @ 33.04 Mlb/hr		41.92 @ 33.36 Mlb/hr	
Loop Design Flow With 15% plugging, gpm (Mlb/hr)	86900 (33.01 @ T_{COLD} = 543.1 F)			14
Primary Side Volume/SG, ft^3 Inlet Plenum, ft^3 Outlet Plenum, ft^3 Tubes, ft^3	942.3 133.4 133.4 675.5	1	969.6 129.65 129.65 710.3	2
Secondary Pressure, psia No tubes plugged 10% tubes plugged 15% tubes plugged 20% tubes plugged	 829.7 746.5 727.0 N/A****	 1 14 14	 876.7 N/A N/A 786.7	2
Total Secondary Volume, ft^3	4579	1	4512.7	2
Secondary Liquid Mass, lb_M Full Power Zero Power	 85410** 130120	1	 86257*** 118836	9

*Calculated
**Includes five percent instrument error; no process error.
***Includes 5.2 percent process error; no instrument error.
****N/A denotes not available.

3. SCOPE OF EVALUATION

All accident analyses presented in Chapter 15 of the Ginna UFSAR were evaluated to determine the effects of replacing the original steam generators with BWI RSGs. The objective of each evaluation was to demonstrate that the analysis presented in the UFSAR bounded Ginna with BWI RSGs or that the plant response continued to meet all acceptance criteria following steam generator replacement.

Other accident analyses are contained within the UFSAR. The main steam line break and loss-of-coolant accident analyses for reactor building pressure response are discussed in section 5.9. The overpressure protection analyses in Chapter 5 are addressed in section 5.10. In some instances, an analysis presented in the current revision of the UFSAR (Rev. 10) may not represent the expected content at the time of the 1996 replacement (i.e. analyses currently under NRC review). In those cases, documents other than the UFSAR were reviewed to determine the effect of steam generator replacement on the accident analyses. Similarly, the station blackout (SBO) coping analysis that satisfies the requirements of 10 CFR 50.63 is not reported in the UFSAR. Separate documentation on that analysis was used to perform the evaluation of the effects of steam generator replacement on the SBO coping analysis (section 5.11).

4. METHODOLOGY

The acceptance criteria for each event were taken directly from the UFSAR or were determined based on the frequency classification of that event in the Standard Review Plan (NUREG 0800). The plant parameters (e.g. reactivity coefficients, valve capacities, fluid volume, tube surface area, etc.) that affect the calculated approach to the acceptance criteria were identified. These plant parameters were compared to identify any changes from the OSG to the RSG.

Once the applicable steam generator parameter differences were determined for each event, an evaluation was performed to verify either that the accident analyses in the UFSAR bound the Ginna response with BWI RSGs or that the plant response continued to meet all acceptance criteria following steam generator replacement. For those cases that could not be shown to meet the acceptance criteria using a simple evaluation, confirmatory computer analyses are being performed.

Each event was evaluated assuming that all safety system actuation setpoints remain unaltered following steam generator replacement. Any differences in safety system actuation times or plant conditions caused by the RSG design were evaluated for each event.

Also, the consequences of certain accidents in the UFSAR are bounded by those of other accidents. As part of this evaluation it was determined that those accidents would continue to be bounded following steam generator replacement with BWI RSGs.

5. EVALUATION

The evaluations of the Ginna accident analyses are presented in this chapter, which is arranged to correspond to the presentation in the Ginna UFSAR. Overcooling events are discussed in section 5.1. Overheating events are discussed in section 5.2. Events that result in a decrease in primary system flow rate are evaluated in section 5.3. Reactivity events are evaluated in section 5.4. Events that cause an increase in reactor coolant system inventory are discussed in section 5.5. Section 5.6 contains the evaluation of accidents that cause a decrease in reactor coolant system inventory. Radioactive releases from subsystems or components are evaluated in section 5.7. Compliance with the anticipated transient without scram rule is evaluated in section 5.8. The effects of steam generator replacement on the overpressure protection analyses are discussed in section 5.9. The steam line break and large break loss-of-coolant accident analyses for containment building overpressure are evaluated in section 5.10. Finally, the effects of steam generator replacement on the station blackout coping analysis for 10 CFR 50.63 are evaluated in section 5.11.

5.1 Increase in Heat Removal by the Secondary System

5.1.1 Decrease in Feedwater Temperature

This event is a sudden reduction in feedwater enthalpy at full power caused by loss of one feedwater heater. The reduction in feedwater enthalpy increases the primary-to-secondary heat transfer by an amount equal to the feedwater heater capacity. As the primary system cools, reactor power increases due to moderator reactivity feedback. The reactor reaches an equilibrium condition where the increase in core power equals the increase in steam generator heat removal. Because the reactor does not reach the overpower or overtemperature ΔT setpoints, no fuel pins experience departure from nucleate boiling (DNB).

A decrease in feedwater temperature is a moderate frequency event. Consequently, no fuel pins can experience DNB. The critical parameter for this event is the capacity of the failed feedwater heater stage because the steam generator heat removal rate and the core power increase by an amount equal to the lost heater capacity. Since steam generator replacement does not affect the feedwater heaters, the consequences of this event are not affected by steam generator replacement with BWI RSGs.

5.1.2. Increase in Feedwater Flow

Increase in feedwater flow is evaluated at two plant conditions. Increase in feedwater flow at full power is evaluated to verify minimum DNBR is not violated. Increase in feedwater flow at zero power is evaluated to determine that the reactivity addition rate is bounded by the startup accident. Both cases are discussed below.

5.1.2.1 Increase in Feedwater Flow at Full Power

The addition of excess feedwater to the steam generators results in an increase in the heat removal from the primary coolant system. The resultant decrease in the average temperature of the core causes an increase in core power due to moderator and control system feedback. When the steam generator liquid level reaches the high-level setpoint, the main feedwater control system terminates feedwater until the level falls below the setpoint. The net result is an overcooling of the primary system, while the steam generator level rises to the high-level setpoint. Thereafter, the system returns to a new equilibrium condition, with the steam generator level controlled to the high-level setpoint. Under actual plant conditions, the primary system would equilibrate at the initial operating condition. However, the analyses in the UFSAR were performed with a coincident increase in steam demand to maximize the overcooling. Consequently, the primary system reached equilibrium at a core power greater than the initial value.

The UFSAR states the acceptance criteria as:

1. Critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the limiting value at any time during the transient.

2. Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressure.

3. Fuel temperature and fuel clad strain limits should not be exceeded.

Since an increase in main feedwater flow is an overcooling transient, the reactor power increases because of the negative end-of-cycle moderator temperature reactivity coefficient. The primary system pressure decreases because of the contraction of the reactor coolant. The increase in power and decrease in primary system pressure cause a reduction in DNBR. The overcooling and, therefore, the reduction in DNBR are functions of the increase in feedwater flow. The additional energy removed from the primary system is equal to the energy required to saturate the additional subcooled feedwater. Since the UFSAR analyses of this event were performed with a prescribed increase in feedwater flow (200 percent feedwater to one steam generator or 160 percent feedwater to both steam generators),[3] the energy that would be removed from the primary system with BWI RSGs is identical to that calculated for the OSGs.

Furthermore, the operating pressure of the BWI RSG, with as many as 20 percent plugged tubes, is greater than that of the OSGs. Therefore, the feedwater flow to the RSG following a control valve failure would be less than that to the OSG because of the greater head across the feedwater pumps. Consequently, steam generator replacement does not adversely affect the calculated value of minimum DNBR and the UFSAR calculation remains bounding for Ginna with BWI RSGs.

The increase in feedwater flow transient results in a primary system cooldown and, therefore, primary system design pressure is not challenged.

The calculated secondary system pressure decreases during the increase in feedwater flow event because the steam load is increased in the analysis to compensate for the energy addition via the increased feedwater. Consequently, secondary system pressure would not exceed 110 percent of design pressure. This would also be the case for the BWI RSG for the same method of analysis.

5.1.2.2 Increase in Feedwater Flow at Zero Power

The system response and sequence of events are not provided in the UFSAR for this event. This event is analyzed to show that the reactivity insertion rate caused by the overcooling is bounded by that analyzed in the startup event. The reactivity insertion rate is a function of the rate of primary system cooling and of the moderator temperature reactivity coefficient.

The primary system cooldown rate is directly related to the energy required to saturate the excess feedwater flow. Since the feedwater flow is prescribed (110 percent of full power feedwater flow),[4] the primary system cooldown rate with BWI RSGs would be the same as with the OSGs. Furthermore, steam generator replacement has no effect on core reactivity coefficients. Consequently, the UFSAR analysis of this event remains bounding for Ginna with BWI RSGs and the reactivity insertion rate during an increase in feedwater flow at zero power remains bounded by the startup event.

5.1.3 Excessive Load Increase Incident

An excessive load increase incident is defined as a rapid increase in steam generator steam flow that causes a mismatch between the reactor power and the steam generator heat removal. The resultant cooling of the reactor coolant causes an increase in reactor power due to a negative end-of-cycle moderator temperature coefficient and a reduction in primary system pressure due to the contraction of the reactor coolant. The increase in power and decrease in primary system pressure cause a reduction in DNBR.

The acceptance criteria for this event are:

1. Critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the limiting value at any time during the transient.

2. Primary and secondary system pressure should not exceed 110 percent of the design limit.

Four cases are presented in the Ginna UFSAR for the excessive load increase event.[5] The four cases are a ten percent increase in load with maximum and minimum reactivity feedback and with reactor control in manual and automatic. The excessive load increase with minimum reactivity feedback and reactor control in manual resulted in an increase in DNBR. Consequently, this case is not limiting. The other cases show that the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow (110 percent). In each case the equilibrium value of DNBR was less than the initial value. However, DNBR was greater than the limit for the entire transient.

The calculated MDNR for this event is unaffected by steam generator replacement because the primary system overcooling and the equilibrium reactor power are fixed by the increase in steam load. Steam generator replacement could only affect the rate of the primary system response. Because the unplugged RSG heat transfer area is 43 percent greater than the OSG heat transfer area with 15 percent tube plugging, the primary system would reach the equilibrium power and average temperature more quickly with the RSGs. Because the steam load increase is a specified constant (ten percent), the primary system cooldown and the equilibrium power would be the same regardless of steam generator design. Consequently, the predictions of minimum DNBR and system pressures presented in the UFSAR for the excessive load increase event are bounding for the Ginna plant with BWI RSGs.

5.1.4 Inadvertent Opening of a Steam Generator Relief/Safety Valve

The effects of a relief/safety valve inadvertent opening are analyzed as part of the spectrum of steam line breaks.

5.1.5 Spectrum of Steam System Piping Failures Inside and Outside of Containment

A steam system piping failure, or steam line break (SLB), results in blowdown of the affected steam generator and severe overcooling of the primary system. With a negative moderator temperature reactivity coefficient, the primary system cooldown results in a reduction of core shutdown margin. If the most reactive control rod is assumed to be stuck in its fully withdrawn position, the core can become critical and return to power. The return to power, with the large local flux peak in the region of the stuck control rod, could result in fuel pins experiencing DNB.

Following a SLB upstream of the main steam isolation valves, the affected steam generator will depressurize due to the excess steam flow. The reduction in secondary saturation temperature will increase the primary-to-secondary heat transfer and cause a reduction in primary system temperature. A low steam line pressure safety injection signal will cause a reactor trip. As the primary system cools, the core shutdown margin decreases due to a negative moderator temperature reactivity coefficient. The safety analyses assume the highest worth control rod is stuck out of the core. Consequently, the core returns to critical and core power increases until an equilibrium condition is reached where the core power matches the energy removal via the SLB. By necessity, the negative reactivity insertion due to power Doppler feedback matches the positive reactivity insertion due to moderator temperature feedback in this equilibrium condition. This condition typically yields the minimum fuel pin DNBR because the primary system pressure is at a minimum and the core power is at a maximum value. Eventually the affected steam generator approaches dryout and the heat removal cannot support the elevated core power. Consequently, the average primary system liquid temperature increases and the core power decreases. In addition, boron addition to the primary system via safety injection adds negative reactivity to the core and eventually ensures long term core shutdown.

Steam system piping failures are classified as design basis events. This means that some fuel pins can experience DNB as long as the offsite whole-body and thyroid doses remain within 10 CFR 100 limits. However, the steam system piping failure is analyzed

to show that DNBR remains above the design limit at all times. Consequently, the spectrum of steam system piping failures includes relief/safety valve failures for which no fuel pins may experience DNB.

UFSAR section 15.1.5 presents five steam line break cases analyzed to assess core response of the Ginna plant:

a. Double-ended 4.6 ft^2 break inside containment from zero power conditions. Offsite power is available and two loops are in service.

b. Double-ended 4.6 ft^2 break inside containment from zero power conditions. Offsite power is lost coincident with the steam line break and two loops are in service.

c. Failure of one steam generator safety valve with offsite power available and two loops in service.

d. Case a with only one reactor coolant loop in service.

e. Case c with only one reactor coolant loop in service.

Those analyses show that the double-ended steam line break cases bound the safety valve failure cases with respect to return-to-power because of the severity of the primary system cooldown that results from the double-ended SLB.

The calculated DNBR during the SLB event is most strongly a function of primary system pressure, core power and reactor coolant flow rate. The primary system pressure is a function of the primary system cooldown rate and the core power response. The core power response is a function of the primary system cooldown rate and core reactivity coefficients. Since the peak core power is reached well before the affected steam generator dries out, variations in initial steam generator inventory have do not affect peak core power.

The steam generator parameters that determine the primary system cooldown rate are SLB flow area and primary-to-secondary heat transfer area. The BWI RSG has a flow orifice in the steam exit nozzle. Consequently, any steam line rupture is limited in size to 1.4 ft^2 with the BWI RSG.[2] This means that the steam generator blowdown rate with the BWI RSG would be seventy percent less than that calculated in the UFSAR cases.

If all other parameters were unchanged, the RCS cooldown rate with the RSGs would be seventy percent less than that calculated with the OSGs. The unplugged RSG has thirty-five percent more heat transfer surface area than the OSG (see Table 2-1) with ten percent plugged tubes. If all other parameters were unchanged, the RCS cooldown rate with the RSGs would be no more than thirty-five percent greater than that calculated with the OSGs. A seventy percent reduction in the RCS cooldown rate (due to the RSG orifice) offsets a thirty-five percent increase in the RCS cooldown rate (due to the greater RSG heat transfer area). The net result is that the primary system cooldown rate following a postulated SLB with BWI RSGs would be less than that calculated in the Ginna UFSAR for the double-ended rupture.

Since the primary system cooldown rate during a SLB with the BWI RSGs would be less than that calculated in the UFSAR, the minimum primary system pressure would be greater and the core power would be less than the values calculated in the UFSAR for the double-ended SLB. This means that the minimum DNBR following a SLB with the BWI RSGs would be greater than that calculated for the limiting cases in the Ginna UFSAR. Consequently, the double-ended SLB analyses in the Ginna UFSAR are bounding for the Ginna plant with BWI RSGs. Also, due to the relatively small cooldown rate associated with a steam generator safety valve failure, the double-ended SLB analyses in the Ginna UFSAR are bounding for a steam generator safety valve failure on the Ginna plant with BWI RSGs.

As already stated, the calculated value of DNBR is sensitive to core flow. The RSG flow resistance with up to 18 percent tube plugging is less than that of the OSG with 15 percent of the tubes plugged.[6] Consequently, the primary system flow rate with BWI RSGs and 18 percent tube plugging will be greater than that calculated in the UFSAR analyses. Therefore, the UFSAR SLB calculations bound the Ginna plant with BWI RSGs and tube plugging up to 18 percent.

[illegible]

5.1.6 Combined Steam Generator Atmospheric Relief Valve and Feedwater Control Valve Failures

The spurious opening of a steam generator atmospheric relief valve with a coincident failure of a feedwater control valve would provide an overcooling event more severe than the overfeed event evaluated in UFSAR section 15.1.2 or than the safety valve failure event evaluated in UFSAR section 15.1.5. The reduction in primary system temperature due to the overcooling would cause a positive reactivity insertion due to a negative moderator temperature reactivity coefficient. The reactivity insertion would cause an increase in reactor power if the reactor is initially critical or it could cause a return to criticality if the reactor is initially shutdown. A power increase with the reduction in primary system pressure associated with an overcooling event would cause a reduction in minimum DNBR.

UFSAR section 15.1.6.1.3 states the acceptance criteria for this event as:

1. Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design pressure.

2. Critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the limiting value at any time during the transient.

3. Fuel temperature and fuel clad strain limits should not be exceeded. The peak linear heat rate should not exceed a value that would cause fuel centerline melt.

This event is an overcooling event caused by depressurization and overfeed of the affected steam generator. Therefore, primary and secondary system pressures decrease throughout the event. Consequently, primary and secondary system pressure responses are bounded by the loss-of-electrical load event.

The UFSAR states that twenty different cases were simulated to calculate minimum DNBR for this event. This run matrix includes atmospheric relief valve failures with and without feedwater control valve failures. Asymmetric conditions were analyzed wherein a feedwater control valve failure was taken on the loop opposite the one with the relief valve failure. In addition, control system effects were analyzed by running each case with

control rods in manual and with control rods in automatic control mode. Lastly, the cases were initiated from full power and from zero power conditions.

The core responses calculated for the hot zero power cases were found to be bounded by the double-ended steam line break calculations in UFSAR section 15.1.5. Because the cooldown rate for a large steam line break is much greater than for the combined valve failure, the large steam line break causes a return to power that is not observed for the combined valve failure. This relationship is unaffected by differences between the OSG and RSG

Five scenarios were analyzed at full power with and without automatic rod control:

1. A stuck open atmospheric relief valve in one loop.
2. Stuck open atmospheric relief valve in both loops.
3. A stuck open atmospheric relief valve and a failed open feedwater control valve in the same loop.
4. A stuck open atmospheric relief valve and a failed open feedwater control valve in opposite loops.
5. Stuck open atmospheric relief valves and feedwater control valves in both loops.

The UFSAR states the limiting case initiated from full power is a failure of atmospheric relief valves and feedwater control valves on both steam generators with control rods in manual. This is the limiting case because it causes the greatest cooldown of the primary system which, in turn, results in the greatest peak core power and minimum primary system pressure. This case will continue to be the limiting case after steam generator replacement because two stuck open relief valves with two failed open feedwater control valves will always cause a greater cooldown rate of the primary system than any of the other scenarios.

In the limiting case, both steam generators depressurized at a rate determined by the valve capacity. The increase in primary-to-secondary heat transfer caused by the increase in steam and feedwater flow caused the primary system to cool. The reduction

in average system temperature caused an increase in core power due to the negative moderator temperature reactivity coefficient. The reactor tripped on overpower ΔT in 11.4 seconds.[7] Following a time delay of 2 seconds,[8] the control rods began to fall into the core. The core power peaked at approximately 14 seconds and then decreased because of control rod insertion. The minimum value of DNBR was reached at the time of peak power.

The parameters that most strongly affect the rate of power increase and, therefore, the approach to the DNBR design limit are the feedwater overfeed rate and the relief valve steam flow rate. The overfeed rate to the RSG during this event would be less than for the OSG because the RSG operates at a greater secondary pressure than the OSG. However, this beneficial effect on the transient is small because the heat removed from the primary due to the overfeed is limited to that required to saturate the excess feedwater. This heat removal is small compared to the heat removed due to the excess steam load.

The primary-to-secondary heat removal due to the increase in steam generator steam flow is a function of the relief valve capacity (valve area). Replacement of the OSGs with BWI RSGs has no effect on the secondary relief valve critical flow areas. The clean, unplugged RSG will, however, operate at a greater secondary pressure than does the OSG, so the steam flow rate through the relief valves will be greater than that predicted in the UFSAR. The clean, unplugged BWI RSG will operate at a secondary pressure of 877 psia.[2] The UFSAR does not state if tube plugging effects were modeled. With respect to core power response, it is conservative to consider this event with no tube plugging. However, to maximize the difference between the RSG and OSG, it is assumed that the OSG was modeled with ten percent tube plugging. Therefore, the secondary pressure of the OSG is 746.5 psia.[1] Consequently, the secondary relief valve flow on the RSG will be 17.5 percent greater than that for the OSG.

If the relief valve flow is 17.5 percent greater than that for the OSG, the calculated cooldown rate, the reactivity insertion rate, and the rate of power increase for this event could be 17.5 percent greater with the RSGs. Consequently, the calculated value of

minimum DNBR for the limiting case in UFSAR section 15.1.5 would not bound the core response with BWI RSGs. However, the minimum DNBR for this event with BWI RSGs is bounded by the minimum DNBR calculated for the total loss-of-reactor coolant flow event.

This event, the combined failure of relief valves and feedwater control valves on both steam generators, will be analyzed using RELAP5/MOD2. The Ginna plant configuration with the OSGs will be modeled to provide a baseline analysis. The event will be reanalyzed with the RSGs. The change in peak core power is expected to be much less than one percent of full power. The resultant power-to-flow ratio with the RSGs will be compared to that of the total loss of flow event in the UFSAR to demonstrate that the minimum DNBR for the total loss of flow is bounding for this event.

5.2 Decrease in Heat Removal by the Secondary System

5.2.1 Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow

The effects of a steam pressure regulator malfunction are bounded by the loss of external load event discussed in Section 5.2.2.

5.2.2 Loss of External Electrical Load

The postulated loss of external electrical load (LOEL) is caused by trip of the turbine generator via closure of the turbine stop valves. Tripping the turbine results in a rapid increase in secondary pressure. Secondary pressure increases to the main steam safety valves (MSSVs) lift pressure. The turbine trip results in a loss of heat sink which causes a primary to secondary heat mismatch. The RCS temperature and pressure increase until a reactor trip is initiated on high pressurizer pressure. Core power is reduced due to reactor trip and the primary system pressurization is terminated by the lifting of the PSVs. Long term heat removal is provided by auxiliary feedwater and subsequent steam relief through the MSSVs.

The loss of external load event is a moderate frequency event and is subject to the following acceptance criteria:

1. Pressure in the reactor coolant and main steam systems shall not exceed 110% of the design value.
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

Since the primary pressure increases during this event, and since the reactor coolant pumps remain running, minimum DNBR is bounded by the flow coastdown event (5.3.1).

The UFSAR states that four cases were analyzed to determine the effect of LOEL on peak primary and secondary system pressures. The limiting case with respect to peak primary and secondary system pressures is the loss of load from full power without automatic control rod control, pressurizer pressure control, condenser steam dump, or atmospheric steam dump.

The parameters that affect the peak secondary pressure are steam production rate, MSSV characteristics, and the pressure differential between the MSSVs and the peak pressure location in the steam generator. The steady-state steam production rate of the OSG is within 0.9 percent of that for the RSG (Table 2-1). The main steam safety valve (MSSV) characteristics are not affected by the replacement steam generator. Since the steam production rates do not differ significantly and the MSSV characteristics are not altered by the steam generator replacement, the peak steam dome pressure of the RSG should be equivalent to that of the OSG following turbine stop valve closure. There will be a small difference in the peak pressures because of the difference in internal steam generator pressure differentials. However, the replacement steam generator pressure will remain below the acceptance criterion following a LOEL event. Confirmatory analyses will be performed to verify that the peak RSG pressure remains below the acceptance criterion following a LOEL event.

The peak RCS pressure is a function of the initial secondary pressure, PSV relief capacity, and high pressurizer pressure reactor trip setpoint. Upon turbine stop valve

(TSV) closure, the secondary pressure increases from its initial value to the MSSV lift pressure. The associated increase in saturation temperature causes an increase in the RCS cold leg temperature. This, in turn, causes an increase in RCS pressure that is terminated by reactor trip. The most severe primary system pressurization will occur for the lowest initial secondary pressure condition due to the larger change in secondary saturation temperature following TSV closure. Consequently, the limiting steam generator condition for the LOEL event is with the maximum number of plugged tubes.

Steam generator replacement does not affect the PSV relief capacity or the high pressurizer pressure reactor trip setpoint. To determine if the peak RCS pressure response with BWI RSGs is bounded by the UFSAR analysis, a comparison of the initial steam generator pressures is made between the UFSAR analysis of the OSG and that expected for the RSG. The case with the lower initial steam pressure will have the greatest peak primary system pressure because the increase in secondary pressure to reach the MSSV lift setpoint and the time required to reach the lift setpoint will be greater than for the steam generator with the greater initial steam pressure.

The BWI RSG operates at a steam pressure of 790 psia with 20 percent of the tubes plugged.[2] The cold leg temperature with 20 percent tube plugging is 544 F.[2] To operate at 540.7 F (design cold leg temperature[2] 544.7 F minus 4 F for control band error and measurement uncertainty), the secondary saturation temperature must be reduced 3.3 F. Saturation temperature at 790 psia is 516.8 F. Therefore, the new secondary saturation temperature would be 513.5 F. The pressure corresponding to this saturation temperature is 768 psia.

The initial steam pressure assumed in the UFSAR analysis was 727 psia.[14] This value is 41 psi less than the operating pressure of the BWI RSG with maximum tube plugging. Consequently, the peak primary system pressure in the UFSAR analysis bounds the value that would be obtained with the BWI RSG because the increase in secondary saturation temperature following the LOEL is the greatest for the UFSAR analysis. Confirmatory analyses will be performed to demonstrate that the peak RCS pressure will remain below the acceptance criterion following a LOEL with BWI RSGs.

5.2.3 Turbine Trip

The analysis of the consequences of an instantaneous turbine trip by closure of the turbine stop valves is the initiating event for the loss of external electrical load (5.2.2). The discussion presented in 5.2.2 is valid for the turbine trip event.

5.2.4 Loss of Condenser Vacuum

Loss of condenser vacuum can occur from failure of the circulating water system or excessive air leakage through turbine gland packing. In the event of loss of condenser vacuum, the turbine will be tripped. Instantaneous turbine trip by closure of the turbine stop valves is the initiating event for the LOEL event. Therefore, loss of condenser vacuum is bounded by the LOEL.

5.2.5 Loss of Offsite Alternating Current (AC) Power to the Station Auxiliaries

A complete loss of offsite AC power, assuming a unit trip, results in loss of power to the RCPs, the RCCA drive mechanisms, and a loss of main feedwater. As a result of the loss of power to the RCPs, the pumps begin to coastdown at event initiation. The flow coastdown will cause a reduction in DNBR. However, the loss of offsite AC power causes reactor trip at event initiation due to loss of power to the RCCA drive mechanism. Since the reactor trips at the same time the RCPs begin to coastdown, the loss of coolant flow accident (5.3.1) bounds the event response with respect to DNB.

The loss of main feedwater resulting from loss of power to the condensate booster pumps would normally result in an increase in RCS pressure. However, the loss of main feedwater is coincident with reactor trip on loss of power to the RCCA drive mechanism. Therefore, the peak RCS pressure for this event is bounded by the normal loss of main feedwater event because it results in a later reactor trip on high pressurizer pressure.

The loss of offsite AC power event is also analyzed to confirm the ability of the combined primary and secondary system to provide core decay heat removal during natural circulation. The parameters that influence natural circulation heat removal are steam generator elevation relative to the reactor core, auxiliary feedwater flow rate, steam

generator primary side pressure drop (flow resistance), steam generator heat transfer area, and secondary mass inventory. The steam generator elevation and auxiliary feedwater flow rate are not affected by steam generator replacement. The primary side pressure drop indicates flow resistance and, therefore, can affect natural circulation flow rate. The primary side pressure drop for the OSG, with 15 percent plugged tubes, is 40.88 psi at full power (Table 2-1). The pressure drop for the RSGs is less than this value for up to 18 percent plugged tubes. Therefore, the RSGs would result in higher natural circulation flow if the RSG heat transfer area is greater than or equal to that of the OSG. The secondary side heat transfer area for the OSG with 15 percent plugged tubes is 37,766 ft^2. The secondary side heat transfer area of the RSG with 18 percent plugged tubes is 44281 ft^2. Because the primary side steam generator resistance is less and the heat transfer area is greater for the RSGs, they will provide higher natural circulation flows. Furthermore, the liquid inventory in the RSG at the low-low level trip setpoint, 45981 lb,[10] is greater than that for the OSG at the low-low level trip setpoint, 42520 lb.[11] Therefore, the heat removal capability of the RSGs exceed that of the OSGs.

Because the RSGs will provide higher natural circulation flows and the RSGs have a greater heat removal capacity, the UFSAR analysis of the loss of offsite AC power remains bounding for the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.2.6 Loss of Normal Feedwater Flow

A loss of normal feedwater results in a reduction in secondary heat removal. The resulting heat removal mismatch causes a primary system pressurization. If the reactor is not tripped during this accident, primary plant damage could occur due to the loss of heat sink.

The loss of normal feedwater flow is a moderate frequency event and is subject to the following acceptance criteria:

1. Pressure in the reactor coolant and main steam systems shall not exceed 110% of the design value.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

3. An ultimate heat sink for decay heat removal must be assured.

4. There can be no liquid relief through the pressurizer PORVs or safety valves.

The loss of normal feedwater would result in a reduction in steam generator liquid inventory. The steam generator liquid inventory boils off until the low-low level setpoint is reached. This signal actuates auxiliary feedwater and trips the reactor. The UFSAR analysis assumes that the reactor coolant pumps are tripped on reactor trip. After a 60 second delay, 200 gpm AFW flow is assumed to start to one steam generator. This flow alone is insufficient to remove core decay heat. Consequently, steam generator inventory decreases until the heat removal from AFW matches core decay heat.

At the time of reactor trip and the time period immediately following, the RCS temperatures, pressure and flow are the same as the loss of reactor coolant flow event because the RCS conditions do not change during the reduction in secondary inventory to the trip setpoint. Therefore, the loss of reactor coolant flow event bounds the loss of normal feedwater with respect to DNBR.

The RCS and secondary pressure responses for a loss of normal feedwater are bounded by the LOEL event. The peak RCS pressure is less than that for the LOEL because the reactor and turbine trip at about the same time for a loss of feedwater, minimizing the mismatch in primary-to-secondary heat transfer. The peak secondary pressure is less than that for the LOEL because, unlike the LOEL event, the reactor trips at the time of turbine trip, providing less heat transfer to the secondary. These relationships are valid regardless of steam generator type. Consequently, the peak primary and secondary pressures for the loss of feedwater event with RSGs remains bounded by those predicted for the LOEL event.

The ultimate heat sink following a loss of normal feedwater is ensured by heat removal via auxiliary feedwater injection and by boiling the initial steam generator liquid inventory.

The steam is relieved through the MSSVs. The RSG will not affect the AFW flow rate, the AFW delay time or the steam relief capacity of the MSSVs. The RSG liquid inventory at the low-low level trip setpoint would be approximately 45981 lb.[10] The OSG liquid inventory at the low-low level trip setpoint would be approximately 42520 lb.[11] Consequently, the RSG has a greater capacity to remove core decay heat. Therefore, the analysis presented in the UFSAR bounds the Ginna plant with BWI RSGs.

Because the UFSAR analysis bounds the Ginna plant with BWI RSGs, and because the pressurizer did not go solid in the UFSAR analysis, the pressurizer would not go solid following a loss of normal feedwater with the BWI RSGs.

5.2.7 Feedwater System Pipe Breaks

A feedwater line rupture produces a rapid blowdown of the affected steam generator through the feedwater nozzle. The initial portion of the transient exhibits similar behavior to that of an overcooling transient because the rapid depressurization of the affected steam generator causes a large reduction in secondary saturation temperature. Following dryout of the affected steam generator, the RCS would heat up until the heat removal from AFW exceeds the core decay heat. The primary system pressure would increase until the pressurizer safety valves (PSVs) open.

The rupture of a feedwater pipe is considered a limiting fault event and is subject to the following acceptance criteria:

1. Pressure in the reactor coolant and main steam systems shall not exceed 110% of the design value.
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.
3. An ultimate heat sink for decay heat removal must be assured.

The analysis in the UFSAR shows that the primary system pressure increases to the pressurizer safety valve (PSV) setpoint where it remains as liquid is vented from the pressurizer.[15] This would also be the case following steam generator replacement

because the relief capacity of the PSVs is far greater than the RCS liquid expansion rate. Consequently, RCS pressure would not exceed 110 percent of the design value following a FWLB with BWI RSGs.

The unaffected steam generator would pressurize following closure of the turbine stop valves upon reactor trip. However, the initiator for the LOEL event is an instantaneous turbine stop valve closure. Consequently, the steam generator pressure response for this event is bounded by the LOEL event (section 5.2.2).

Similar to the loss of normal feedwater event, the ultimate heat sink is ensured via auxiliary feedwater injection to the unaffected steam generator and by boiling of the initial liquid inventory in the unaffected steam generator. The UFSAR analysis assumed that two hundred gpm AFW flow started ten minutes after reactor trip, which was assumed to occur when the steam generator was dry.[16] The assumption that the reactor tripped when the steam generator was dry, rather than on low-low water level, over-predicts the energy addition to the RCS by several full-power seconds. This conservative assumption offsets any differences in liquid inventory between the RSG and the OSG. Furthermore, the liquid mass in the RSG at the low-low level trip setpoint would be approximately 45981 lb.[10] The liquid mass in the OSG at the low-low level trip setpoint would be approximately 42520 lb.[11] Consequently, the decay heat removal capacity of the unaffected RSG exceeds that for the unaffected OSG. Therefore, the analysis presented in the UFSAR bounds the Ginna plant with BWI RSGs.

5.3 <u>Decrease in Reactor Coolant System Flow Rate</u>

5.3.1 Flow Coastdown Accidents

A loss of coolant flow event can result from a mechanical or electrical failure in one or more reactor coolant pumps or from a fault in the power supply to these pumps. If the reactor is at power, the loss of coolant flow results in a rapid increase in coolant temperature. This increase in temperature, combined with the reduced core flow, could

result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor is not tripped promptly.

Two cases are examined in the Ginna UFSAR:

1. A loss of two pumps from rated power.
2. A loss of one pump from rated power.

The loss of two reactor coolant pumps is the most limiting with respect to minimum DNBR.[12]

The postulated loss of both reactor coolant pumps (RCPs) results in a rapid reduction in reactor coolant flow. The flow reduction results in an increase in reactor coolant temperature. The temperature increase, coupled with the positive moderator temperature reactivity coefficient, produces a positive reactivity insertion, which increases core power. The increase in core power and reduction in flow reduces the DNBR. The continued decrease in loop flow causes a reactor trip on low reactor coolant flow.

This event is a moderate frequency event with the following SRP acceptance criteria:

1. Pressure in the reactor coolant and main steam systems shall not exceed 110% of the design value.
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

The important parameters that affect the approach to the DNBR limit are the initial RCS flow, RCP moments of inertia, and the reactor protection system (RPS) low coolant flow trip delay time. The impact of the BWI RSGs on each of these parameters is discussed below.

The steady-state RCS flow determines the margin to the DNBR limit. The initial RCS flow is a function of the system pressure drop. The higher the system pressure drop, the lower the initial RCS flow. The only component of the total RCS pressure drop that is affected by the steam generator replacement is the primary side nozzle-to-nozzle

pressure drop in the steam generator. The response of the Ginna plant to this event was shown to be acceptable with up to 15 percent plugged tubes in the OSG.[23] The pressure drop for the RSG with up to 18 percent plugged tubes is less than that for the OSG with 15 percent plugged tubes (Table 2-1). Therefore, the initial RCS flow with the RSGs will be greater and the initial margin to the DNB limit will be higher. In addition, the reactor trip occurs when the loop flow reaches 87 percent of the initial value.[8] Since the initial RCS flow with the RSGs will be greater than that with the OSGs, the margin to DNB will also be greater at the time of reactor trip.

The reactor coolant flow coastdown is driven by the RCP inertia and to a lesser extent, the total loop pressure drop. The RSGs do not affect the RCP inertia. As discussed above, the RSGs have a lower pressure drop than the OSGs. The smaller pressure drop will have a slightly beneficial effect by slowing the flow coastdown. The effect is small, however, and need not be credited in this evaluation.

The delay time for the low reactor coolant flow instrument string is a function only of the equipment comprised by the trip string and will be unaffected by the steam generator replacement.

The RSG does not adversely affect any of the parameters that determine the minimum DNBR reached for the total loss of forced reactor coolant flow. Therefore, the loss of coolant flow analyses presented in the Ginna UFSAR bound the Ginna plant with BWI RSGs.

5.3.2 Locked Rotor Accident

The locked rotor accident is analyzed considering a postulated seizure of an RCP rotor. Flow through the RCS is rapidly reduced, leading to a reactor trip on low flow. The rapid flow reduction results in a decrease in the DNBR. Following reactor trip and subsequent rod insertion, the DNBR increases.

This event is classified as a limiting fault. The UFSAR states the following acceptance criteria:

1. Peak RCS pressure shall not exceed 120% of the design value.
2. Peak clad temperature shall not exceed 2700 F.

The parameters that affect the peak clad temperature and the peak RCS pressure are initial primary system flow, locked RCP rotor resistance, pressurizer safety valve (PSV) flow, low reactor coolant flow trip delay time, and total primary system loop resistance. The steady-state RCS flow determines the initial margin to the DNBR limit. The initial RCS flow is a function of the system pressure drop. The higher the system pressure drop, the lower the initial RCS flow. The only component of the total RCS pressure drop that is affected by the steam generator replacement is the primary side nozzle-to-nozzle pressure drop in the steam generator. The pressure drop for the OSGs with 15 percent tube plugging is 40.88 psi. The pressure drop of the BWI RSGs is less than this value with up to 18 percent plugged tubes (Table 2-1). Since the RSGs have a lower pressure drop, the total loop resistance with the RSGs will be lower than that of the OSGs. Therefore, the initial RCS flow with the RSGs will be greater and the initial margin to the DNB limit will be higher.

The locked RCP rotor resistance is based on the configuration of the RCP rotor after the failure resulting in the rotor lockup. This resistance is not affected by steam generator replacement. Likewise, neither the PSV flow nor the low reactor coolant flow trip delay time are affected by the steam generator, so the steam generator replacement does not affect these parameters.

The reactor coolant flow coastdown is driven by the locked RCP rotor resistance and, to a lesser extent, the total loop pressure drop. The RSGs do not affect the locked RCP rotor resistance. In addition, the reactor trip occurs when the loop flow reaches 87 percent of the initial value. Since the initial loop flow with the RSGs is greater than with the OSGs, the margin to DNB is increased for this event following steam generator replacement.

Since none of the parameters that affect peak clad temperature or peak RCS pressure for the locked rotor transient are adversely affected by the steam generator replacement, the UFSAR analysis bounds the Ginna plant with BWI RSGs.

It is indicated in UFSAR Table 15.0-1[13] that the locked rotor analysis was performed assuming 15 percent plugged tubes in the OSGs. The RCS flow rate with RSGs and 18 percent plugged tubes is greater than that with OSGs and 15 percent tube plugging (Table 2-1).[6] Therefore, the UFSAR analysis of the locked rotor event bounds the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.4 Reactivity and Power Distribution Anomalies

5.4.1 Uncontrolled Rod Cluster Control Assembly Withdrawal from a Subcritical Condition

A rod cluster control assembly (RCCA) withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of rod cluster control assemblies resulting in a power excursion. While a continuous withdrawal of a RCCA is considered unlikely, the reactor protection system is designed to terminate any such transient before fuel thermal design limits are reached.

The power excursion resulting from the RCCA withdrawal results in a primary-to-secondary heat mismatch. As the primary system heats up, the positive moderator coefficient results in positive reactivity insertion. The power increase, coupled with the coolant temperature increase, reduces the margin to DNB. The RCS pressurizes until a reactor trip on power range flux level (low setting) is reached. The reactor trip reduces core power and reduces the heat mismatch. The RCS pressure peaks and then declines due to steam/liquid relief through the PSVs and heat removal via auxiliary feedwater.

An uncontrolled withdrawal of a RCCA from a subcritical condition is classified as a moderate frequency event with the following applicable acceptance criteria:

1. Peak primary and secondary system pressure shall not exceed 110% of design value.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

The parameters that affect the response to the RCCA withdrawal from subcritical conditions are reactivity insertion due to rod motion, initial axial power distribution, moderator temperature reactivity coefficient and Doppler reactivity coefficient. These parameters are not affected by steam generator replacement.

The effects of tube plugging on the margin to DNB were evaluated in the UFSAR. The evaluation concluded that sufficient margin existed to accommodate 15 percent tube plugging in the OSGs. The RCS flow rate with RSGs and 18 percent tube plugging is greater than that with OSGs and 15 percent tube plugging. Therefore, the UFSAR analysis of the startup event bounds the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.4.2 Uncontrolled Rod Cluster Control Assembly Withdrawal at Power

An uncontrolled RCCA withdrawal at power results in an increase in core power. Since the heat removal via the steam generators remains constant, there is a net increase in reactor coolant temperature. Unless terminated by manual or automatic action, this power mismatch and resultant coolant temperature rise would eventually result in DNB. The RPS is designed to terminate any such transient with an adequate margin to DNB.

The uncontrolled withdrawal of a RCCA at power event is a moderate frequency event with the following acceptance criteria:

1. Peak primary and secondary system pressure shall not exceed 110% of design value.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

An uncontrolled withdrawal of a RCCA at power causes a heat mismatch between core power and secondary heat removal. The mismatch results in an increase in primary coolant temperature and pressure. As the primary system heats up, the positive moderator coefficient produces a positive reactivity insertion. The power increase, coupled with the coolant temperature increase and asymmetric rod position, reduces the margin to DNB. The RCS heats up and pressurizes until a reactor trip on nuclear flux overpower, high pressurizer level, or overtemperature ΔT is reached. The reactor trip reduces core power and reduces the heat mismatch. The RCS pressure peaks and then declines because of relief through the PSVs and heat removal via the steam generators.

Since steam generator heat removal was held constant in the UFSAR analysis, the plant response to the RCCA withdrawal from power is solely a function of core parameters. These include reactivity insertion due to rod motion, initial axial power distribution, moderator temperature reactivity coefficient and Doppler reactivity coefficient. None of these parameters are affected by steam generator replacement.

The RCCA withdrawal event analysis in the UFSAR was performed with 15 percent plugged tubes in the OSGs.[13] The RCS flow rate with RSGs and 18 percent tube plugging is greater than that with OSGs and 15 percent tube plugging.[6] Therefore, the UFSAR analyses of the RCCA withdrawal events bound the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.4.3 Startup of an Inactive Reactor Coolant Loop

Operation of the plant with an inactive loop causes reversed flow through the inactive loop because there are no isolation valves or check valves in the reactor coolant loop. If the reactor is operated at power in this condition, the coolant temperature in the inactive loop is colder than that in the other loop. The subsequent restart of the idle reactor coolant pump results in the injection of cold water into the core. This infusion of cold water coupled with the increased coolant flow rate causes a reduction in the average coolant temperature in the core region. With a negative moderator temperature reactivity

coefficient, a reduction in core average coolant temperature causes a rapid reactivity addition to the core.

The startup of an inactive reactor coolant loop is a moderate frequency event with the following acceptance criteria:

1. Peak primary and secondary system pressure shall not exceed 110% of design value.
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

The parameters that affect the system response to this event are initial power level, coolant temperature in the inactive loop, moderator temperature coefficient, and inactive pump time constant. The maximum initial power level is the maximum power level for one pump operation permitted by the Technical Specifications (8.5 percent).[17, 18] The coolant temperature in the inactive loop was assumed to be equal to the saturation temperature at secondary pressure. At 8.5 percent power, the secondary saturation temperature was conservatively assumed to be 20 F lower than the hot leg temperature of the active loop. The moderator temperature coefficient used was the most negative value during time of core life. The RCP time constant to full flow was considered to be 0.0 seconds (instantaneous transition to full flow). None of these parameters are affected by steam generator replacement. Therefore, the results presented in the Ginna UFSAR bound the Ginna plant with BWI RSGs.

5.4.4 Chemical and Volume Control System Malfunction

The chemical and volume control system (CVCS) regulates both the chemistry and the quantity of coolant in the RCS. Inadvertent operation of the CVCS resulting in injection of deborated water into the RCS would cause a reduction in RCS boron concentration. Boron dilution in any operational mode adds positive reactivity to the core. Depending on the time given to terminate the dilution, the resulting positive reactivity insertion could result in a power excursion and result in a reduction in the DNBR and core thermal margins.

The inadvertent dilution of the RCS via the CVCS is a moderate frequency event and has the following acceptance criteria:

1. Peak primary and secondary system pressure shall not exceed 110% of design value.
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

The parameters that affect the response to the boron dilution event are the minimum required shutdown margin, dilution flow rate, critical boron concentration, and total RCS volume. The replacement of the OSGs with BWI RSGs does not affect the minimum shutdown margin, dilution flow rate, or critical boron concentration. The replacement steam generator primary side volume is 27 ft^3/SG larger than that of the OSGs (Table 2-1). The larger volume of the RSGs reduces the reactivity insertion for a given dilution flow rate. The lower reactivity insertion rate will result in a smaller reactor power increase for the at power transient and a slower increase in reactivity for the shutdown dilution events. Therefore, the UFSAR analyses bound the Ginna plant with BWI RSGs.

The analysis of CVCS malfunction (boron dilution) analyzed for the Ginna UFSAR included the effects of 15 percent tube plugging on the margin to DNB for the startup and at power dilution cases.[13] The RCS flow rate with RSGs and 18 percent tube plugging is greater than that with OSGs and 15 percent tube plugging.[6] Furthermore, the primary side volume of the OSG with 15 percent plugged tubes, 841 ft^3 (Table 2-1), is less than the primary side volume of the RSG with 18 percent plugged tubes, 842 ft^3 (Table 2-1). Therefore, the UFSAR analyses of CVCS malfunction bound the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.4.5 Rupture of a Control Rod Drive Mechanism Housing - RCCA Ejection

The RCCA ejection is a postulated event caused by rupture of the control rod drive housing. The rupture results in a rapid ejection of a RCCA. The resultant positive reactivity insertion and subsequent core power excursion is limited by the Doppler reactivity effects of the increased fuel temperature and is terminated by reactor trip on high nuclear power.

[illegible]

The ejection of a RCCA is classified as a limiting fault event and is subject to the following acceptance criteria as stated in the UFSAR:

1. Average fuel pellet enthalpy at the hot spot shall not exceed 200 cal/g.
2. Peak reactor coolant pressure shall not cause stresses to exceed the faulted condition stress limits.
3. Fuel melting will be limited to less than the innermost 10% of the fuel volume at the hot spot.

The primary parameters that affect the fuel pellet enthalpy, RCS pressure, and centerline fuel melting are time in core life, ejected rod worth, Doppler temperature/power coefficient, and PSV flow rate. None of these parameters are affected by steam generator replacement. Consequently, the UFSAR analyses of RCCA ejection bound the Ginna plant with BWI RSGs.

The limiting rod ejection cases were analyzed to include the effects of 15 percent tube plugging on the fuel pin response.[13] The RCS flow rate with RSGs and 18 percent tube plugging is greater than that with OSGs and 15 percent tube plugging.[6] Therefore, the UFSAR analysis of the RCCA ejection event bounds the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.4.6 RCCA Drop

Dropping of a full length RCCA could occur if the drive mechanism is de-energized. The rod drop would cause a power reduction and an increase in the hot channel peaking factor. If no protective action occurred, the reactor control system would restore core power level to the pre-dropped level. This could result in DNB due to the abnormal core peaking induced by the dropped control rod.

The dropped RCCA event is a moderate frequency event and is subject to the following acceptance criteria:

1. Peak primary and secondary system pressure shall not exceed 110% of design value.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

The parameters that affect the response to the RCCA drop accident are dropped rod worth, moderator temperature reactivity coefficient, Doppler reactivity coefficient and core flow rate. The dropped rod worth, moderator temperature reactivity coefficient and Doppler reactivity coefficient are unaffected by steam generator replacement.

The RCS flow rate influences the event response since the minimum DNBR is a function of the core flow. This event was evaluated for 15 percent tube plugging in the OSGs.[13] The RCS flow rate with RSGs and 18 percent tube plugging is greater than that with OSGs and 15 percent tube plugging (Table 2-1). Therefore, the UFSAR analysis of the RCCA drop accident bounds the Ginna plant with BWI RSGs and up to 18 percent plugged tubes.

5.5 Increase in Reactor Coolant Inventory

5.5.1 Inadvertent Actuation of the Emergency Core Cooling System

Inadvertent actuation of the emergency core cooling system (ECCS) or a chemical and volume control system malfunction that increases the reactor coolant inventory can lead to an increase in system pressure and pressurizer level. During power operation, system pressure is higher than the pump shutoff head of the high pressure safety injection pumps. Therefore, inadvertent actuation of the ECCS cannot result in an increase in primary inventory.

The three positive displacement charging pumps can deliver a maximum of 180 gpm at nominal system pressure. If the injection is not terminated by the operator upon receipt of the various alarm signals, the reactor will trip on high pressurizer pressure or level.

The inadvertent actuation of the ECCS is a moderate frequency event and is subject to the following consequences:

1. Peak primary and secondary system pressure shall not exceed 110% of design value.
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for the correlation used.

The parameters that affect the system response to this event are initial pressurizer level, injection flow rate, PORV flow rate, and PSV flow rate. These parameters are not affected by the steam generator replacement. Therefore, the analysis in the Ginna UFSAR remains bounding for the steam generator replacement with BWI RSGs.

5.6 Decrease in Reactor Coolant Inventory

5.6.1 Inadvertent Opening of a Pressurizer Safety or Relief Valve

The inadvertent opening of a pressurizer safety or relief valve or the failure to close following an overpressurization transient, can cause a decrease in reactor coolant inventory and subsequent reduction in reactor coolant system RCS pressure. If the valve is not closed, the continuing depressurization leads to a reactor trip on low RCS pressure, overtemperature ΔT, or high pressurizer level.

The inadvertent opening of a pressurizer safety or relief valve is a moderate frequency event. The standard review plan (SRP) acceptance criteria for this event class are:

1. Pressure in the reactor coolant and main steam systems shall not exceed 110% of the design values
2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit based on acceptable correlations.

Upon opening of the pressurizer safety or relief valve, the RCS would depressurize due to venting of the pressurizer steam. The depressurization of the RCS would result in a decrease in the DNBR. The rate at which the DNBR approaches the correlation limit

depends on the RCS depressurization rate and core power. The continued venting of steam would cause the pressurizer liquid level to rise and approach the high pressurizer level trip. Depending on the relief capacity of the valves, the reactor would trip on low RCS pressure, overtemperature ΔT, or high pressurizer level. Following reactor trip, the rapid reduction in core power produces an increase in the DNBR. The primary system pressure would continue to decrease until safety injection actuates on low pressure. High pressure injection flow ensures that the core remains covered during the event.

The approach to DNB is a function of the RCS depressurization rate and the core power prior to RCCA insertion following reactor trip. The RCS depressurization is governed by the relief capacity of the pressurizer safety or relief valve(s). Core power is determined by moderator density and Doppler temperature reactivity feedback. The RSG does not affect the relief capacity of the pressurizer safety or relief valves nor does it affect the reactivity feedback. Therefore, with respect to minimum DNBR, the analysis referenced in the UFSAR bounds the Ginna plant with BWI RSGs.

The UFSAR states that a generic analysis showed that no core uncovering would occur for breaks on the pressurizer of 0.008 ft^2 or 0.034 ft^2. Since the breaks were postulated on the pressurizer, the vessel mixture level would decrease no lower than the hot leg nozzle elevation. This would provide a direct path for core steam to exit the break and allow system refill for cases of a failure of a train of safety injection. In the case of full safety injection flow, the injection flow would exceed the single-phase liquid discharge through the failed valve and core uncovering would be prevented.

With respect to system response and the possible approach to core uncovering, the generic analysis referenced in the UFSAR bounds the Ginna plant with RSGs. The RSGs contain 27 ft^3 more primary volume per steam generator than the OSGs. This means that the RSGs have more margin to core uncovering. Also, the RSGs have 22 percent more heat transfer surface area than do the OSGs. Consequently, should the system transition to reflux boiling mode of cooling, the primary pressure with the RSGs would be lower than that with the OSGs because the RSGs would provide greater condensation than the

OSGs. This means that the break discharge flow would be less and the safety injection flow would be greater than calculated in the generic analysis performed in the UFSAR.

5.6.2 Radiological Consequences of Small Lines Carrying Primary Coolant Outside Containment

The postulated rupture of small lines carrying primary coolant outside containment would result in a leakage of radioactive primary coolant to buildings outside containment, ultimately resulting in offsite releases.

This event is classified as a limiting fault event and the acceptance criterion is that the offsite whole-body and thyroid doses shall not exceed 10 CFR 100 limits.

The rupture of a small line carrying primary coolant outside containment leads to a reduction in RCS pressure and inventory similar to that in a small break loss-of-coolant accident. The RCS depressurization will produce a reactor trip on low RCS pressure or overtemperature ΔT, depending on the size of the line. Upon reactor trip, all lines leaving containment are isolated. This isolation terminates the RCS depressurization and inventory loss. Therefore, the primary system response to this event is bounded by the small break loss of coolant accident (UFSAR section 15.6.4).

The primary coolant discharge to buildings outside containment is governed by the size of the rupture and initial RCS pressure. The replacement of the steam generator does not affect either of these factors, so, the analysis remains bounding for the steam generator replacement.

5.6.3 Steam Generator Tube Rupture

The rupture of a steam generator tube is a breach of the barrier between the reactor coolant system and the main steam system. Primary coolant is discharged to the secondary where it mixes with the water on the shell side of the affected steam generator. Radioactivity can be transported by steam through the turbine to the

condenser. Non-condensible radioactive gases in the condenser are removed by the condenser air ejector discharge to the atmosphere.

Following rupture, the steam generator blowdown liquid monitor and/or the condenser air ejector radiation monitor will actuate an alarm indicating a sharp increase in radioactivity in the secondary system. The continued loss of primary inventory will cause a reduction in RCS pressure and pressurizer level. Upon receipt of a low pressurizer level signal, the charging pump flow will increase in an attempt to maintain pressurizer level. The decrease in RCS pressure will lead to a reactor trip on low pressurizer pressure or overtemperature delta T. Following reactor trip, the radioactive release continues until the RCS is cooled and depressurized below the secondary pressure of the affected steam generator.

The steam generator tube rupture (SGTR) is a limiting fault event with the following SRP acceptance criteria:

1. The offsite doses for an initial RCS activity of 1 µCi/g with an accident initiated iodine spike should not exceed 10 percent of 10 CFR 100 dose limits.

2. The offsite doses for an initial RCS activity of 60 µCi/g with no iodine spike should not exceed 10 CFR 100 dose limits.

Two cases were analyzed for the licensing bases of the Ginna plant. The first case analyzed the double-ended rupture of a single steam generator tube with a failure of a steam generator pilot operated relief valve (PORV) to close on the affected steam generator. This case usually provides the worse case offsite doses. The second case examined the primary and secondary system response following a double-ended SGTR with primary system cooldown and depressurization delayed by a failure of the PORV on the unaffected steam generator to open. This case provides the worse case with respect to steam generator overfill. In both cases, loss-of-offsite power was assumed coincident with reactor trip.

5.6.3.1 SGTR for Limiting Offsite Dose

The parameters important to the calculation of offsite dose for this event are the integrated leakage into the secondary system and RCS activity concentration. The integrated leakage into the secondary system is a function of the break area. The OSG has an inner tube diameter of 0.775 inches and the RSG has an inner tube diameter of 0.664 inches (Table 2-1). This means that the break flow for an RSG tube is 26.6 percent less than that of an OSG tube. The smaller leak flow from the RSG would delay reactor trip. The mass leaked to the RSG up to reactor trip, however, would be approximately the same as that for the OSG. Also, the blowdown of the affected steam generator to the atmosphere following reactor trip is the same for either steam generator type because the capacity of the PORV is not changed by steam generator replacement. Consequently, the primary-to-secondary leakage for an SGTR on the RSG would be significantly less than that for the OSG.

The RCS activity utilized in the UFSAR calculations corresponded to the maximum allowed concentration permitted by the Technical Specifications. This concentration limit is not affected by the steam generator replacement. Consequently, the existing calculation of the limiting SGTR event with respect to offsite dose bounds the Ginna plant following replacement of the OSGs with BWI RSGs.

5.6.3.2 Limiting SGTR With Respect to SG Overfill

The RSG tube area is 26.6 percent less than that of the OSG. Therefore, the integrated leak flow should be less for the RSG than for the OSG and the RSG should have more margin to overfill than the OSG. However, the secondary volume of the RSG is approximately 66 ft^3 (Table 2-1) less than that of the OSG, indicating less margin to overfill. Because one RSG parameter serves to mitigate the transient results and one RSG parameter serves to aggravate the transient results, a RELAP5/MOD2 analysis of this SGTR event will be performed using a Ginna plant model with the OSGs. The analysis will serve as a baseline for

comparison with an identical analysis of this event with the RSGs. The comparison will demonstrate that the RSG has a greater margin to overfill than does the OSG.

5.6.4 Loss of Coolant Accident

5.6.4.1 Loss of Reactor Coolant From Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates Emergency Core Cooling System

The effects of the BWI RSGs on the primary and secondary system responses to a small break loss of coolant accident are evaluated in a separate document.[24] That evaluation showed that the changes in parameters for the replacement steam generators are beneficial to plant response following the worse case SBLOCA.

5.6.4.2 Major Reactor Coolant System Pipe Ruptures (Loss of Coolant Accident)

The effects of the BWI RSGs on the primary and secondary system response to a large break loss of coolant accident are being evaluated by the owner, in conjuction with the fuel vendor.

5.7 Radioactive Release From a Subsystem or Component

5.7.1 Radioactive Gas Waste System Failure

Two separate cases are considered in the UFSAR for radioactive gas waste system failure. One case is a gas decay tank rupture. The second case is a volume control tank rupture. Each case is discussed below.

5.7.1.1 Waste Gas Decay Tank Rupture

The waste gas decay tanks contain the gases vented from the reactor coolant system, the volume control tank, and the liquid holdup tanks. Sufficient volume is provided in each of four tanks to store the gases evolved during a reactor shutdown. The waste gas accident is defined as an unexpected and uncontrolled release to the atmosphere of the radioactive xenon and krypton fission gases that are stored in the wasted gas storage system.

The waste gas decay tank rupture accident is a limiting fault event. The acceptance criteria are:

1. The offsite dose shall not exceed 10 CFR 100 limits.
2. The dose to control room personnel shall not exceed 5 rem.

The activity in a waste gas decay tank was taken to be the maximum amount that could accumulate from operation with cladding defects in 1 percent of the fuel elements. The maximum activity was obtained by assuming that all of the xenon and krypton accumulated with no release over a full core cycle. The equivalent activity is 46,000 Ci equivalent Xe-133. The accident was evaluated with an instantaneous release of the entire tank activity to the atmosphere.

The parameters important for the dose calculations are RCS activity concentration and site specific dispersion factors. The total radioactive noble gas inventory from one full core cycle is not affected by the replacement of the Ginna steam generators with BWI RSGs. Site dispersion factors are a function of the meteorology of the site and are not affected by steam generator replacement. Therefore, the consequences of the waste gas decay tank rupture accident presented in the Ginna UFSAR bound the Ginna plant with BWI RSGs.

5.7.1.2 Volume Control Tank Rupture

The volume control tank contains fission gases and low concentrations of halogens which are normally a source of waste gas activity vented to a waste gas decay tank. The iodine concentrations and volatility are quire low at the temperature, pH, and pressure of the fluid in the volume control tank. The volume control tank is assumed to rupture and disperse the release at ground level.

The volume control tank rupture accident is a limiting fault event. The acceptance criteria are as follows:

1. The offsite dose shall not exceed 10 CFR 100 limits.

2. The dose to control room personnel shall not exceed 5 rem.

The activity in the volume control tank was assumed to include:

1. All the contained noble gases.

2. The contained iodine in the fraction that evaporates.

3. The small amount of iodine contained in the 60 gpm flow from the demineralizers, which would continue for up to 5 minutes before isolation would occur.

Plant operation with one percent defective fuel was assumed.

The parameters important for the dose calculations are volume control tank activity and site specific atmospheric dispersion factors. The total activity in the volume control tank is not affected by the replacement of the Ginna steam generators with BWI RSGs. Site dispersion factors are a function of the meteorology of the site and are not affected by steam generator replacement. Therefore, the consequences of the volume control tank rupture accident presented in the Ginna UFSAR bound the Ginna plant with BWI RSGs.

5.7.2 Radioactive Liquid Waste System Failure

Several postulated failures of tanks within the liquid waste system were examined. These include failures of all liquid waste tanks in the auxiliary building and failure of the spent resin storage tank.

5.7.2.1 Liquid Waste Components

Accidents in the auxiliary building which would result in the release of radioactive liquids are those which may involve the rupture or leaking of system piping or storage tanks. The largest vessels are the three liquid holdup tanks, each sized to hold two-thirds of the reactor coolant liquid volume. These tanks are used to process the normal recycle or waste fluids produced. The contents of one tank is passed through the liquid processing train while another tank is being filled.

All liquid waste components except the reactor coolant drain tank are located in the auxiliary building and any leakage from the tank or piping is collected in the building sump to be pumped back into the liquid waste system. The building sump and basement volume is sufficient to hold the full volume of a liquid holdup tank without overflowing to areas outside the building.

The parameters important for the dose calculations are tank volume, auxiliary building sump volume, basement volume, and liquid activity. None of these parameters are affected by the replacement of the Ginna steam generators with BWI RSGs. Therefore, the consequences of the liquid waste system failure accident discussed in the Ginna UFSAR remain bounding for the Ginna plant with BWI RSGs.

5.7.2.2 Credibility of Accidental Release of Liquid Waste

The UFSAR provides an evaluation of the credibility of the accidental release of radioactive fluids from the waste disposal system discharge. The evaluation concluded that the administrative controls imposed on the operator, combined with the safety features built into the liquid waste system, provide a high degree of assurance against accidental release of waste liquids. Steam generator replacement does not affect administrative controls or the waste liquid system. Therefore, the UFSAR evaluation remains valid for the Ginna plant following steam generator replacement.

5.7.2.3 Consequence of Tank Failure in the Auxiliary Building

Should a complete failure of any tank located in the auxiliary building occur, the contents would remain in the building. Any subsequent discharge of radioactive liquid to the lake would be conducted under administrative controls and would not result in the discharge of activity concentrations into the lake in excess of the limits given in the Technical Specifications. Steam generator replacement does not affect administrative controls regarding liquid discharge. Consequently, the

UFSAR discussion remains valid for the Ginna plant following steam generator replacement.

5.7.2.4 Spent Resin Storage Tank Failure

In the event of a loss of water from a spent resin storage tank, a low level alarm actuates to warn the operator. Resin in the tank is then cooled by periodically flushing water from the reactor makeup water tank through the resin. Two separate means are available to provide coolant for the resin. Calculations have been performed to determine the required frequency of injecting coolant through the resin tank to prevent resin degradation. The resin temperature is controlled until the resin can be removed to burial facilities.

The replacement of the OSGs with BWI RSGs has no impact on this event. Therefore, the discussion presented in the Ginna UFSAR remains valid following replacement of the OSGs with BWI RSGs.

5.7.3 Fuel Handling Accident

The fuel handling accident can be defined as any event that results in application of forces on the fuel assembly that may result in rupture of one or more fuel rods. The consequences of a fuel handling accident that results in failure of one or more fuel rods is a potential offsite release or control room exposure.

Fuel handling accidents outside and inside containment are evaluated in the UFSAR. The dose consequences for a fuel handling accident outside containment are a function of the fuel rod gap fission gas activity of the damaged fuel assembly and the efficiency of charcoal filters in the auxiliary building. Neither of these parameters is affected by steam generator replacement. Therefore, the conclusions in the UFSAR remain valid for the Ginna plant with BWI RSGs.

The fuel handling accident inside containment is assumed to result in rupture of all 179 rods in one fuel assembly. No credit is taken for containment isolation or effluent filtration. Other assumptions were made based on Regulatory Guide 1.25.

The dose consequences for a fuel handling accident inside containment are a function of the fuel rod gap fission gas activity of the hottest fuel assembly and the reactor cavity pool decontamination factor. Steam generator replacement does not affect fuel assembly fission gas activity or refueling pool decontamination factor. Therefore, the accident is not affected by steam generator replacement.

5.8 Anticipated Transients Without Scram (ATWS)

An ATWS is an anticipated operational occurrence (such as loss of feedwater, loss of condenser vacuum, or loss of offsite power) that is accompanied by a failure of the reactor trip system to shut down the reactor. The ATWS rule described in 10 CFR 50.62 requires specific improvements in the design and operation of commercial nuclear power facilities to reduce the probability of failure to shut down the reactor following anticipated transients and to mitigate the consequences of an ATWS event.

5.8.1 Effect of RSGs on AMSAC

The Ginna plant has ATWS mitigating system actuation circuitry (AMSAC) that mitigates the consequences of an ATWS by initiating auxiliary feedwater and by tripping the turbine on a loss of feedwater flow.[21] The circuitry is active when the reactor power is between 40 and 100 percent power. Following a low feedwater flow signal, actuation of the AMSAC mitigation actions is delayed by the time required to boil down the steam generators to the low-low level reactor trip setpoint. This delay is implemented using a variable timer. The time delay varies with plant power as measured by turbine impulse pressure.

The AMSAC design is not affected by steam generator replacement since no circuitry will be replaced due to the RSG installation. Neither the actuation of AMSAC on a low

feedwater flow signal or the mitigation actions of AMSAC are affected by steam generator replacement because they are external to the steam generator.

The AMSAC time delay could be affected by steam generator replacement because the time to boil down the RSG to the low-low level trip setpoint could be different than that for the OSG. State-point calculations at normal and low-low steam generator levels will allow the boil down time to be determined for the RSG. If required, a simple adjustment of the timer delay can be made following steam generator replacement. Since the AMSAC is administratively controlled, a change in the delay would not require a change to the Technical Specifications.

Since the AMSAC is unaffected by steam generator replacement, the Ginna plant will meet the requirements of the ATWS rule following steam generator replacement with BWI RSGs. When the RSG design is finalized, the AMSAC timer delay should be calculated from state-point mass calculations to be performed by BWI.

5.8.2 Effect of RSGs on Results of WCAP-8404

Westinghouse Electric Corporation analyzed a number of ATWS events for Westinghouse-designed pressurized water reactors with 44 series steam generators.[22] The events considered in that study include:

1. Rod withdrawal from subcritical conditions.
2. Rod cluster control assembly bank withdrawal at power.
3. Boron dilution.
4. Partial loss of forced reactor coolant flow.
5. Startup of an inactive reactor coolant loop.
6. Loss of external electrical load and/or turbine trip.
7. Complete loss of normal feedwater.
8. Loss of AC power to the station auxiliaries (station blackout).

9. Excessive load increase.
10. Accidental depressurization of the reactor coolant system.
11. Rod drop.

The study showed that for each event the minimum DNBR was greater than the design value and the peak primary system pressure was less than .service level C limits. Furthermore, it was demonstrated that the loss of feedwater event was the limiting event for peak primary system pressure. In addition, a loss of feedwater ATWS event with a failure of the turbine to trip leads to a primary system pressure in excess of 3800 psia. The AMSAC system is designed to mitigate this particular event by tripping the turbine and initiating AFW (section 5.8.1). Use of the R000SGs does not alter the conclusions in WCAP-8404. The effects of the RSGs on each event are discussed below.

5.8.2.1 Rod Withdrawal From Subcritical Conditions

The rod withdrawal from subcritical causes increases in core power and in primary system pressure. The power increase terminates when the rod bank is completely out of the core and the primary-to-secondary heat transfer matches the core power. As the steam generator dries out, the primary system liquid temperature increases and the core power declines because of moderator temperature reactivity feedback. However, the pressurizer becomes liquid solid, reducing the volumetric discharge through the pressurizer relief and safety valves. Consequently, peak primary system pressure occurs when the steam generator dries out and the pressurizer goes liquid solid.

Use of the RSGs would have little effect on this event. The peak primary system pressure is a function of pressurizer relief and safety valve capacities and core power response. The core power response is a function of withdrawn rod bank worth, reactivity coefficients and main steam safety valve capacity (secondary heat removal capacity). None of these parameters are affected by steam generator replacement. The RSG has more liquid mass than the OSG. This could affect the time at which the RSG dries out. However, the RSG liquid mass is similar to that

used in the WCAP-8404 analysis. Furthermore, a sensitivity study on liquid mass reported in WCAP-8404 states that variations in steam generator liquid mass have no effect on peak RCS pressure. Consequently, the peak RCS pressure reported in WCAP-8404 remains applicable to the Ginna plant with RSGs.

Because the core power did not exceed 60 percent of full power, the minimum DNBR remained above the design limit. As already stated, the RSGs have no effect on the core power response in WCAP-8404. Therefore, the minimum DNBR for this event would remain above the design limit with the RSGs.

5.8.2.2 Rod Cluster Control Assembly Bank Withdrawal at Power

The transient response to a 0.3 percent Δk/k rod withdrawal from full power was reported in WCAP-8404. As the rods were withdrawn, core power increased, forcing the core temperatures to increase because of the mismatch between core power and secondary heat removal. Moderator and Doppler reactivity feedback terminated the power increase. Core power and secondary heat removal returned to 100 percent as the reactivity feedback from the increased primary system liquid temperature matched the reactivity insertion from the rod withdrawal. Peak primary system pressure occurred during the initial power transient. Pressurizer power operated relief valves limited the peak system pressure to 2350 psia. Consequently, peak system pressure for this ATWS event is bounded by that for the loss of normal feedwater ATWS event.

The peak reactor power and, therefore, pressurizer insurge rate are most strongly functions of the reactivity inserted by withdrawal of the control rod and of the moderator and Doppler reactivity coefficients. These parameters are unaffected by the RSGs. Consequently, the RSGs would have little effect on the minimum DNBR and peak primary system pressure calculated for this event in WCAP-8404.

5.8.2.3 Boron Dilution Event

It is stated in WCAP-8404 that the maximum reactivity insertion due to dilution over a ten-minute period is less than 0.10% dk. Because this insertion is less than that for the uncontrolled rod withdrawal at power, this event is bounded by rod withdrawal at power and no clad damage is expected. This conclusion remains valid for the RSGs because the primary side liquid volume of the RSGs is greater than that of the OSGs (Table 2-1). Consequently, the dilution of the primary system with the RSGs would be less severe than that with the OSGs.

5.8.2.4 Partial Loss of Forced Reactor Coolant Flow

A partial loss of forced reactor coolant flow ATWS event would be a single reactor coolant pump trip with failure of the reactor to trip. It was determined in WCAP-8404 that this event is bounded by the station blackout ATWS event because the power-to-flow ratio for the station blackout event (total loss of forced flow) is much greater than that for the partial loss of flow event. Steam generator replacement does not alter this conclusion.

5.8.2.5 Startup of an Inactive Reactor Loop

Startup of an inactive coolant loop could result in an increase in core power because of the reactivity insertion caused by transport of cold liquid from the inactive loop to the core. Startup of an inactive loop on a 3-loop plant was evaluated in WCAP-8404. That evaluation determined that this event is bounded by the rod withdrawal at power ATWS event. This conclusion is valid for Ginna because the maximum core power in single-loop operation at Ginna is 8.5 percent (see 5.4.3). Consequently, it is unlikely that the Ginna plant could attain full power following startup of an idle loop from 8.5 percent power. Replacement of the OSGs with BWI RSGs does not alter the conclusions in WCAP-8404 for this event.

5.8.2.6 Loss of External Electrical Load and/or Turbine Trip

The plant response to a turbine trip and loss of main feedwater, without reactor trip, was presented in WCAP-8404. It was shown that the primary system pressure reached an initial peak at the time of secondary safety valve lift. Later, as the steam generators dried out, the primary system pressure reached a second, higher peak because the pressurizer was liquid solid when steam generator heat transfer was lost. Peak primary system pressure did not exceed 2750 psig and minimum DNBR did not decrease below the initial value during the transient.

The peak primary system pressure is a function of pressurizer relief and safety valve capacities and core power response. The core power response is a function of core reactivity coefficients and main steam safety valve capacity (secondary heat removal capacity). None of these parameters are affected by steam generator replacement. Consequently, the analysis of this event in WCAP-8404 remains valid for Ginna with BWI RSGs.

The RSG has more liquid mass than the OSG. This could delay the time at which the RSG dries out. However, the time that the steam generator begins to dryout has no effect on the peak pressure. The rate of dryout of the tube bundle affects the peak RCS pressure. The rate of dryout of the tube bundle is primarily a function of the steaming rate (safety valve capacity), which is unchanged by steam generator replacement.

5.8.2.7 Loss of Normal Feedwater

The analysis of this event in WCAP-8404 assumed a loss of main feedwater with turbine trip 30 seconds later. Steam dump to the condenser was assumed to be available following turbine trip and auxiliary feedwater was initiated 60 seconds after the loss of main feedwater. The peak pressure for this event occurred as the steam generator dried out. The pressurizer was already liquid solid when the steam generator began to dry out. The decrease in heat removal from the primary system caused an increase in the surge rate into the pressurizer, causing the

primary system pressure to reach the peak value. The value obtained for the base plant (3-loop) was less than service level C limits.

The peak pressure was greater than that calculated for the LOEL ATWS event because the loss of feedwater analysis assumptions maximized steam flow from the steam generators, which provided a greater core power and a more rapid dryout of the steam generators once the tubes began to uncover. Sensitivity studies also demonstrated this effect on peak primary system pressure. A loss of main feedwater ATWS event with no turbine trip resulted in a system pressure of 3900 psia because the increased secondary steam flow resulted in a greater core power and a more rapid termination of secondary heat removal as the tube bundle dried out. Furthermore, delays in auxiliary feedwater initiation also resulted in an increase in the primary system pressure as compared with the base case.

Steam generator replacement has no effect on the results presented in WCAP-8404 because the peak primary system pressure is a function of pressurizer relief and safety valve capacities, secondary steaming capacity and core power response. The core power response is a function of core reactivity coefficients and secondary system steaming capacity (heat removal capacity). None of these parameters are affected by steam generator replacement.

5.8.2.8 Loss of AC Power to the Station Auxiliaries (Station Blackout)

This event was analyzed for WCAP-8404 assuming coastdown of all reactor coolant pumps from full power, turbine trip, main feedwater pump trip, and actuation of auxiliary feedwater pumps in 60 seconds. The flow coastdown caused an increase in average coolant temperature and an increase in primary system pressure. The increase in coolant temperature caused a significant decrease in core power because of the negative moderator temperature reactivity coefficient. Consequently, for the two-loop analysis, the peak RCS pressure was limited to 2376 psia by the power operated relief valves. Therefore, the primary pressure

response for this event was bounded by the LOEL and loss of main feedwater ATWS events.

The decrease in loop flow caused an initial decrease in DNBR. Minimum DNBR was reached in approximately 15 seconds. After that time, the rate of decrease in core power offset the rate of decrease in core flow, and DNBR increased.

The core and pressure responses to this event are functions of the moderator temperature and Doppler reactivity coefficients, flow coastdown rate and the steam generator mass inventory. The reactivity coefficients are unaffected by steam generator replacement. A sensitivity study in WCAP-8404 showed that minimum DNBR and peak RCS pressure improve with increasing flow coastdown rates. The evaluation of the flow coastdown event in 5.3.1 determined that the flow coastdown with RSGs would be marginally better than with OSGs. Another sensitivity study showed that an increase in steam generator mass of 10 percent resulted in a reduction in MDNBR of 0.05. The RSG liquid inventory (Table 2-1) is less than 10 percent greater than that used in the WCAP-8404 analysis. Therefore, the reduction in DNBR would be very small. Furthermore, there is significant margin between the calculated MDNBR and the design limit. Therefore, a station blackout ATWS event with the RSGs would result in peak primary system pressure less than the design value and minimum DNBR greater than the design value.

5.8.2.9 Excessive Load Increase Event

An increase in steam load of ten percent at full power is the postulated event. The core power would increase to 110 percent as a result of automatic rod control or as a result of moderator temperature reactivity feedback. No reactor trip setpoint would be reached. Consequently, this event is identical to that in 5.1.3. The evaluation in 5.1.3 determined that all acceptance criteria would be satisfied with the RSGs.

5.8.2.10 Accidental Depressurization of the Reactor Coolant System

This event was analyzed as a 2.47 in^2 break in the top of the pressurizer from full power conditions. The primary system rapidly depressurized to saturation. The associated decrease in moderator density caused the core power to slowly decrease. The heat removal by the steam generators decreased proportionally because feedwater was controlled to maintain constant steam generator level. Consequently, the moderator temperature decreased for the remainder of the event. Because the primary system was saturated, primary system pressure slowly decreased throughout the event.

Minimum DNBR (1.68 with high radial peaks) occurred at the time of initial primary system saturation because at that time the core power was near 100 percent and the average coolant temperature was near the initial value. This means that minimum DNBR is a function of only the core power because the core power level sets the fuel pin heat flux and sets the hot leg temperature at which the system will saturate. The Ginna plant can operate at the same core power and hot leg fluid temperature with the RSGs. Consequently, steam generator replacement does not affect the results of the evaluation in WCAP-8404, and minimum DNBR with the RSGs for this ATWS event will remain above the design limit.

5.8.2.11 Rod Drop

A reactor trip is neither called for nor required in the event of a dropped rod since a large margin to DNB is retained in this event. Furthermore, it was determined in 5.4.6 that the RSGs do not impact the UFSAR analysis of this event. Consequently, no cladding would experience DNB for a dropped rod.

5.9 Overpressure Protection

Overpressure protection is ensured during normal operation and during low temperature conditions. Each case is discussed below.

5.9.1 Overpressure Protection During Normal Operation

Verification of the system design to maintain system pressures below 110 percent of the design values is made by referencing the LOEL event in UFSAR section 15.2.2. The evaluation of that event in section 5.2 of this report concluded that the analysis of LOEL in the UFSAR is bounding with respect to the Ginna plant with BWI RSGs. Consequently, system integrity is assured following steam generator replacement.

5.9.2 Low Temperature Overpressure Protection

The UFSAR describes two causes of primary system overpressurization at low RCS temperatures. These two involve events in which there is mass injection to the RCS or there is heat input to the RCS. Inadvertent actuation of three charging pumps with letdown isolated is the limiting case for low temperature overpressure caused by an increase in coolant inventory. The most limiting thermal expansion transient is the startup of a reactor coolant pump with a 50 F temperature difference between the water in the reactor vessel and the water in the steam generator.

The pressurization due to inadvertent actuation of the safety injection system is affected by the injection flow rate, the pilot operated relief valve (PORV) lift pressure, and the PORV flow rate. Replacement of the steam generators does not affect any of these parameters. Therefore, the analysis results of an inadvertent actuation of the safety injection system at low RCS temperatures presented in UFSAR section 5.2.2 bound the Ginna plant with BWI RSGs.

The pressurization of the RCS due to startup of a RCP with a secondary-to-primary ΔT of 50 F is directly affected by changes in steam generator parameters since heat transfer from the steam generators causes the pressurization. The heat transfer during the event is a function of the heat transfer coefficient in the steam generator tubes, the steam generator heat transfer area, and the initial temperature differential (50 F as defined). The BWI RSGs have a heat transfer area of 54001 ft^2 versus the OSG heat transfer area of 44430 ft^2 (Table 2-1). This 22 percent increase in heat transfer area will result in a higher peak RCS pressure prediction with the RSGs than was calculated for the OSGs.

Due to the large difference in heat transfer, an analysis will be performed to verify that the peak RCS pressure for this event remains acceptable following replacement of the steam generators with BWI RSGs.

5.10 Containment Building Pressure Response

The UFSAR identifies two events that are analyzed to determine the peak containment building pressure: the large break loss of coolant accident (LBLOCA) and the main steam line break (MSLB).

5.10.1 LBLOCA For Containment Building Pressure

The steam generator parameters that affect the containment building pressure following a LBLOCA are the initial primary side liquid mass, initial primary liquid internal energy, secondary liquid sensible heat and the steam generator metal sensible heat. The primary side volume of the RSG is 27.3 ft^3 greater than that for the OSG (Table 2-1). Therefore, the initial primary system mass and internal energy will increase following steam generator replacement. This increase in mass and energy will have little effect on the blowdown time of the RCS, but the blowdown peak in the containment pressure would likely increase by approximately 0.3 psi to 0.5 psi. It is conservative to assume that the containment pressure for the duration of the event would be 0.3 psi to 0.5 psi greater than the calculation with OSGs.

The RSG has 22 percent more tube surface area than does the OSG (Table 2-1). Normally this would result in a greater superheating of the steam exiting the primary system through the break during the reflood period of the LBLOCA. However, the UFSAR analysis assumed that the steam was heated to the secondary saturation temperature. This assumption should bound the RSG and there is no effect of steam generator replacement on the reflood peak.

The RSG metal mass and secondary liquid inventory will be greater than the OSG. Consequently, the energy transferred to the building during the post-reflood stage of the

LBLOCA will increase. However, since the containment building pressure decreases during the post-reflood stage, the additional energy transferred from the RSG will have no effect on the peak containment building pressure.

Since the containment pressure following a LBLOCA with RSGs will increase above that calculated for the current plant, the effect of the RSGs on the peak containment pressure will be calculated in a separate task.

5.10.2 SLB For Containment Pressure

RG&E recently re-evaluated the containment building pressure response following SLB.[19] A detailed parametric study was performed to determine the effects of break size, break location, initial power level and single failures on the peak containment building pressure. The worse case SLB resulted in a peak pressure of 59.9 psig. The containment building design pressure is 60 psig.

The RSG design has features that would both aggravate and mitigate the peak containment building pressure. For example, the RSG heat transfer surface area is 22 percent greater than the OSG (Table 2-1). This will increase the energy transfer to the containment building. However, the RSG has a flow orifice in the steam nozzle.[2] This will limit the effective break area to 1.4 ft^2.

Since there are offsetting differences between the RSG and the OSG, it is not possible to determine from a simple comparison of steam generator parameters that the peak containment pressure following a worse case SLB would remain below the design pressure. Consequently, a separate analytical task is already in place to determine the containment building pressure response following a SLB on the BWI RSGs.

5.11 Station Blackout (Total Loss of Offsite/Onsite Power)

The station blackout event is defined in 10 CFR 50.63 as a total loss of offsite and onsite AC power. Each licensee is required to show that the plant has a qualified alternate AC power source or that the plant can cope with a complete loss of AC power for up to four

hours. The Ginna plant does not have an alternate AC power source. Consequently, an analysis of a complete loss of power event is an important part of demonstrating compliance with 10 CFR 50.63.

The SBO coping analysis for Ginna[20] assumed a loss of offsite power as the initiating event. The reactor, the turbine, the reactor coolant pumps and the main feedwater pumps were tripped on the loss of power. Reactor coolant pump seal leaks of 25 gpm/pump were assumed to begin coincident with the loss of power. The emergency diesel generators were assumed to fail. Consequently, no safety injection was available and only the turbine driven AFW pump was available to provide decay heat removal via the steam generators. The event was terminated in the analysis four hours later as offsite power was assumed to be restored.

The acceptance criterion for the station blackout event is that the core shall not uncover.

The SBO event is a cold leg SBLOCA without safety injection. The reactor coolant pump seal leakage is small. Consequently, the RCS would experience a slow loss of inventory while decay heat is removed via natural circulation cooling. Minimum system inventory would be reached at four hours when offsite power and, therefore, safety injection are assumed available to restore RCS inventory.

The parameters that affect the approach to core uncovering are the pump seal leakage and the initial RCS mass. Steam generator replacement does not affect the effective break areas of the pump seal leaks. Consequently, the initial leak discharge is unaffected. The RCS pressure would be lower during the event with RSGs because the greater heat transfer surface area would provide closer coupling to the secondary pressure than would the OSGs. This would reduce the seal leakage, though the effect would be small.

The RSGs have a greater primary side volume than the OSGs (27.3 ft^3/SG). Consequently, the approach to core uncovering would be delayed by the time required to discharge this additional inventory through the pump seal leaks.

In summary, the effect of the RSGs on the SBO response is to delay core uncovering. Therefore, the existing SBO coping analysis bounds the Ginna plant with BWI RSGs.

6. SUMMARY AND CONCLUSIONS

The accident analyses that support the R. E. Ginna UFSAR and Technical Specifications were reviewed to determine the effects of replacing the steam generators with BWI steam generators. The objective was to verify that the analyses remain bounding or that all acceptance criteria continue to be met following steam generator replacement with BWI steam generators.

The evaluation included review of:

1. All UFSAR Chapter 15 events exclusive of large and small break LOCAs.
2. The overpressure protection events in Chapter 5 of the UFSAR.
3. Separate licensing submittals that show compliance with 10 CFR 50.62 (ATWS rule) and 10 CFR 50.63 (Station Blackout).

Except for the cases described below, all of the safety analyses bound the Ginna plant with BWI RSGs with up to 18 percent tube plugging.

The analysis of combined steam generator atmospheric relief valve and feedwater control valve failures in UFSAR section 15.1.6 does not bound the Ginna plant with BWI RSGs. Confirmatory accident analyses will be performed to verify that the combined failure event with BWI RSGs remains bounded by the loss of forced reactor coolant flow event.

The evaluation of the SGTR accident recommended that computer analysis be performed for the limiting case for steam generator overfill. The analysis should verify that the smaller tube diameter (reduced break flow) of the RSG offsets the smaller secondary volume of the RSG.

In addition, the evaluation determined that the design differences between the OSG and the RSG require re-analysis of the limiting low temperature overpressure protection

analyses and the containment building pressure response following steam line break. Furthermore, simple calculations are required to show the effects of steam generator replacement on the peak containment building pressure following a loss of coolant accident and on the AMSAC actuation delay timer.

The evaluation of the loss of external electrical load event in 5.2.2 determined that the primary and secondary pressure responses with the RSGs should meet the acceptance criteria. Computer analysis was recommended to verify this conclusion and to provide validation of the plant model that will be used for other accident analyses.

7. REFERENCES

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6. *RCS Flow Rates For Ginna RSG*, BWNT Document 32-1224865-01.

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9.* *Ginna - RSG Verified Design Data*, BWI Document 222-7705-A19, Rev. 01, Appendix H, Table H1.

10.* *Ginna - RSG Verified Design Data,* BWI Document 222-7705-A19, Rev. 01, Appendix L.

11. RGE Letter R/WNS94-002, *Steam Generator Liquid Mass Following Loss of Feedwater,* BWNT Document 38-1210551-00.

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18. *R. E. Ginna Nuclear Plant Technical Specifications,* Amendment 54, October 1993, Section 3.1.1.1.

19. Robert C. Mecredy, Rochester Gas & Electric, to Allen R. Johnson, USNRC, *RG&E Corp. R. E. Ginna Nuclear Power Plant Docket No. 50-244,* December 17, 1992.

20. Robert C. Mecredy, Rochester Gas & Electric, to Allen R. Johnson, USNRC, *10 CFR 50.63, Loss Of All Alternating Current Power R. E. Ginna Nuclear Power Plant Docket No. 50-244,* April 22, 1991.

21. Carl Stahle, USNRC, to Robert C. Mecredy, RG&E, *Safety Evaluation Report on Compliance With ATWS Rule, 10CFR50.62(c)(1),* March 16, 1989.

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23. Rochester Gas & Electric, *R. E. Ginna Nuclear Power Plant Updated Final Safety Analysis Report,* Section 15.3.1.5, Rev 10, 12/93.

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