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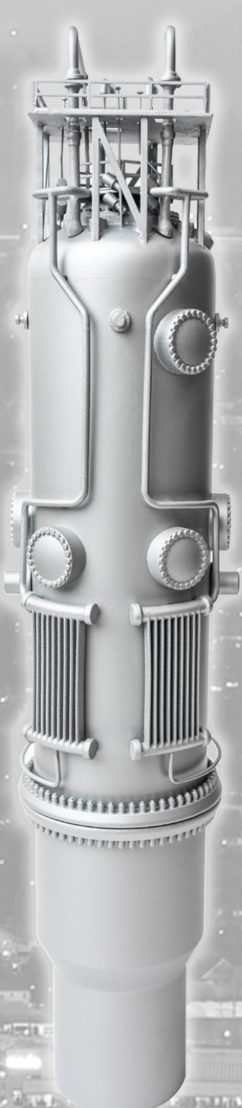
NuScale Standard Plant
Design Certification Application

Chapter Five
Reactor Coolant System and Connecting Systems



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CHAPTER 5 REACTOR COOLANT SYSTEM AND CONNECTING SYSTEMS

5.1 Summary Description

The reactor coolant system (RCS) provides for the circulation of the primary coolant. The NuScale Power, LLC (NuScale) design relies on natural circulation flow for the reactor coolant and does not include reactor coolant pumps or an external piping system. The RCS is a subsystem of the NuScale Power Module (NPM). The RCS includes the reactor pressure vessel (RPV) and integral pressurizer (PZR), the reactor vessel internals (RVI), the reactor safety valves (RSVs), RCS piping inside the containment vessel (CNV) (RCS injection, RCS discharge, PZR spray supply, and RPV high-point degasification lines), the PZR control cabinet and the RCS instruments and cables.

Chapter 1 provides an overview of the NuScale Power Plant design that includes up to twelve individual NPMs. The description in this chapter applies to each of the NPMs individually, unless otherwise stated.

5.1.1 Design Basis

The performance and safety design bases of the RCS and its major components are interrelated. These design bases are listed as follows:

- The RCS promotes natural circulation to transfer approximately 160 MW thermal power from the reactor core to the steam generator system (SGS) during power operation and the heat produced when the reactor is subcritical, including the initial phase of plant cooldown.
- The RCS provides coolant to the reactor core such that specified acceptable fuel design limits are not violated during normal operation including the effects of anticipated operational occurrences.
- The RCS water chemistry is maintained so that solid deposits on the reactor core and the steam generators (SGs) are minimized.
- The RCS maintains a uniform concentration of soluble boron concentration during normal, transient, and accident conditions, and adequate chemical and thermal mixing to maintain reactivity.
- Steady-state temperatures are maintained throughout the reactor coolant to maintain the temperature of the RVI and RPV below design limits during normal and accident conditions.
- The PZR has sufficient capacity to control reactor coolant pressure within the permitted operating range for normal operating transients without actuating the RSVs.
- The RCS removes decay heat from the reactor core during shutdown and refueling operations by a combination of heat transfer to the DHRS through the SGS and convection from the RPV to the reactor pool.
- The RCS provides the water used as the core neutron moderator and reflector blocks that reflect a portion of the neutrons that escape the fuel region, improving neutron economy in the core.

- The RCS provides a degasification line to remove noncondensible gases from the PZR volume at the top of the RPV during normal operation. Reactor vent valves (RVVs), which are opened to discharge the PZR steam space directly to the CNV as part of ECCS operation, also allow noncondensible gases to be removed from the PZR during emergency core cooling operation.
- The pressure-retaining portions of the RCS assist in maintaining the integrity of the reactor coolant pressure boundary (RCPB) that provides a barrier to the release of radionuclides.

5.1.2 System Description

The RCS is a subsystem of the NPM and is located inside the CNV. The RCS includes the RPV, the integral PZR, the RVI, the RSVs, reactor coolant piping inside the CNV and the RCS instruments and controls.

The RCS interfacing systems include the chemical and volume control system via the containment system, the emergency core cooling system (ECCS) valves consisting of RVVs and reactor recirculation valves (RRVs), the CNV, control rod drive system, SGS, and the primary sampling system (through the chemical and volume control system).

A diagram of an individual NPM is provided in Figure 5.1-1 showing the RPV within the CNV and denoting major RCS components. A simplified RCS diagram is provided in Figure 5.1-2.

During normal operation, the RCS transports heat from the reactor core to the SGs by natural circulation. The motive force for the reactor coolant flow is natural convection, driven by differences in coolant density between the hot coolant leaving the reactor core and the colder coolant leaving the SGs, and by the elevation difference between the reactor core (heat source) and the SGs (heat sink). The reactor coolant is heated in the core, travels upward through the lower and upper riser assemblies, and at the top of the upper riser assembly is turned downward by the PZR baffle plate. The heated coolant then flows into the annular space between the upper riser assembly and the vertical shell of the RPV. This annular space contains the SG helical tube bundles. As the reactor coolant flows downward across the outside of the SG tubes, it transfers heat to the secondary coolant inside the tubes. Heat transfer to the SG tubes lowers the temperature of the reactor coolant, increasing its density and causing the cooler, dense coolant to sink into the annular downcomer space between the lower riser assembly and core barrel and continue into the lower plenum near the bottom of the RPV where the reactor coolant returns to the reactor core.

A schematic flow diagram of the RCS is provided in Figure 5.1-3, denoting major components, and major RCS loop flow stages during normal steady-state, full-power operating conditions. In addition, Table 5.1-1 identifies the RCS volumes.

The SGS (in conjunction with the main steam and main feedwater systems) are used to remove decay heat from the RCS during the initial phase of module cooldown. When decay heat is sufficiently low and the RCS temperature is low enough to support filling the CNV, the CNV is filled to the PZR baffle plate by the containment flooding system. RCS cooldown continues passively as decay heat is transferred through the RPV to the flooded containment and through the CNV to the reactor pool. The DHRS actuation valves are opened to allow feedwater to recirculate through the DHRS heat exchangers and secondary water chemistry conditions for wet layup are established. The SGs are then isolated from the main steam and feedwater systems. PZR water level is reduced using the chemical volume control system to match the water level in the CNV in preparation for opening the RVVs and RRVs. Nitrogen is vented from the PZR through the RPV high point degasification line until PZR pressure matches containment pressure. When the PZR and containment pressure and water level are matched, the RVVs and RRVs are opened.

5.1.3 System Components

5.1.3.1 Reactor Pressure Vessel

The RPV is a metal vessel that forms part of the RCPB and is a barrier to the release of fission products. Most of the reactor coolant is contained in the RPV. The RPV is supported laterally and vertically by the CNV. The RPV contains and supports the reactor core, RVI, steam generators, and PZR. The RPV provides penetrations, support, and alignment for the control rod drive system. The RPV also provides penetrations and attachment locations for the RCS instruments, the ECCS valves (RVVs and RRVs), and RCS piping (RCS injection, RCS discharge, PZR spray supply, and RPV high point degasification lines). In addition, the RPV also provides steam and feedwater plenums for the steam generators and RSV penetrations.

The RPV and appurtenances are further described in Section 5.3.

5.1.3.2 Reactor Coolant System Piping

The RCS piping external to the RPV consists of the following lines:

- two PZR spray line branches from a common spray header
- RPV high point degasification line
- RCS injection line
- RCS discharge line

The RCS injection line has branch lines that connect to each of the ECCS valve reset valves.

The RCS piping is further described in Section 5.4.

5.1.3.3 Pressurizer

The PZR, which is integral to the RPV, occupies the volume inside the RPV above the PZR baffle plate. The RCS components in the PZR volume are the PZR spray nozzles (which are part of the RVI) and the PZR heater assemblies. The PZR provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions at a temperature greater than T_{HOT} for pressure control of the RCS during steady-state operations and transients. Maintaining the saturated conditions higher than T_{HOT} ensures the reactor coolant remains subcooled during normal operations. The PZR also serves as a surge volume.

The PZR is further described in Section 5.4.

5.1.3.4 Reactor Vessel Internals

The RVI contain several sub-assemblies that provide support and alignment for the core, the control rod assemblies, the control rod drive shafts, surveillance capsules, and the instrument guide tubes. Additionally, the RVI channel reactor coolant flow from the reactor core to the SGs and back within the RPV.

The RVI sub-assemblies include the core support assembly, surveillance capsule assemblies, lower riser assembly, upper riser assembly, flow diverter, and PZR spray nozzles.

The RVI are further described in Section 3.9.5 and Section 5.3.

5.1.3.5 Reactor Safety Valves

Two pilot operated, self-actuating RSVs connect to the top of the RPV upper head and discharge directly to the CNV. These valves are a part of the RCPB and provide overpressure protection as required by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

The RSVs are further described in Section 5.2.

5.1.3.6 Emergency Core Cooling Valves

The ECCS valves consist of three RVVs and two RRVs. The RVVs connect to the upper head portion of the RPV and discharge the PZR steam space directly to the CNV. Two RRVs connect to the RPV shell just above the main closure flange. When opened, they permit recirculation of water in the CNV back into the RPV and ultimately through the core. The ECCS valves are a part of the RCPB and are used during emergency core cooling operation. The RVVs also provide overpressure protection during operations at low temperature conditions.

The RVVs and RRVs are further described in Section 6.3.

5.1.3.7 Steam Generators

The SGS is an integral part of the RPV (although not a component of the RCS) composed of the SG tubes, SG tube supports, steam and feedwater piping inside containment, SG tube inlet flow restrictors, feed plenums, and steam plenums. The design contains two independent, but intertwined, SGs located inside the RPV that facilitate heat transfer to the secondary coolant system and provide redundancy for the DHRS. The SGs are a once-through, helical-coil design, with primary-side reactor coolant outside the tubes and secondary-side fluid inside the tubes. On the primary side, the reactor coolant flows downward across the outside of the tubes, transferring heat to the fluid inside the SG tubes. On the secondary side, preheated feedwater enters the two feed plenums at the bottom of each SG, flows up the helical tubes where it is heated, boiled, and superheated, and exits the two steam plenums at the top of each SG. The DHRS is connected to the steam and feed piping to permit use of the SG to remove decay heat from the primary coolant.

The SGs are further described in Section 5.4.

5.1.4 System Evaluation

To optimize performance of the NuScale Power Plant over the range of power levels within the design basis, steady state values for primary and secondary side parameters are established as a function of reactor power. The following criteria are considered to define optimal performance: maximizing electrical generation, using support systems efficiently, and providing margin to analytical limits. The following parameters are determined: primary coolant temperatures, primary coolant flow rates, PZR water level, SG water level and mass, feedwater and steam flow rates, feedwater and steam pressure, and steam superheat. The steady state parameters are calculated using the thermal hydraulic software NRELAP5 and are verified by hand calculation.

Calculations establish a best-estimate flow, maximum flow, and minimum flow for the applicable design considerations, as well as the primary coolant temperatures at each flow condition. In establishing the range of design flows, the calculations account for uncertainties in the component flow resistances, the amount of core bypass flow, and the thermal head capability. Bounding uncertainties are determined based on testing data and design requirements.

The pressure losses through the RCS flow path are very low, to support the natural circulation design of the RCS. Since the pressure losses due to flow are small, the pressure at any location in the RCS flow path is primarily a function of the static head. The primary coolant flows over the outside of the helical SG tubes; therefore, SG tube plugging uncertainties are not applicable to the primary coolant natural circulation flow rate determination.

Minimum design flow is the lowest expected value for the primary coolant flow rate and is calculated by biasing analytical uncertainties to minimize the flow rate. Minimum design primary coolant flow rate is used in design analyses where it is bounding to assume a low flow rate.

Maximum design flow is the highest expected value for the primary coolant flow rate. Maximum design flow is calculated by biasing analytical uncertainties to maximize the primary coolant flow rate. Maximum design primary coolant flow rate is used in design analyses where it is bounding to assume a high flow rate.

The module heatup system is used to heat up the RCS and provide primary coolant flow before the reactor is critical. Between hot zero power and 15 percent reactor power, the heat generated from the reactor core is used to heat up the RCS to the normal operating average coolant temperature. Between 15 percent reactor power and full power operating conditions, the average primary coolant temperature is maintained at a constant value. The full power average coolant temperature is higher for higher primary coolant flow conditions, and lower for lower primary coolant flow conditions. This phenomenon provides for similar hot leg temperatures at full power conditions, which allows for the SG to generate sufficient superheat independent of the full power primary coolant flow rate.

The RCS volumes are shown in Table 5.1-1. The thermal-hydraulic design for reactor core coolant flow by natural circulation is discussed in Table 5.1-2 and Section 4.4.

Table 5.1-1: Reactor Coolant System Volumes

RCS Region	Nominal Volume (ft^3)*
Hot Leg (lower riser, riser transition, upper riser, riser supports)	635
Cold Leg [feedwater plenums, downcomer transition, downcomer (lower riser), core barrel, RPV bottom head, flow diverter]	578
Core Region (fuel assembly region and reflector cooling channels)	89
SG Region	621
PZR Region (main steam plenums, PZR, RPV top head)	578
PZR Region, cylindrical (main steam plenums and PZR)	487

*Volumes are rounded to the nearest cubic foot.

Table 5.1-2: Primary System Temperatures and Flow Rates

Reactor Power		Primary Flow		Primary Coolant Temperature			
%	**MWt**	**%**	**(Kg/s)**	**Core dT**	**T_{Cold} (°F)**	**T_{avg} (°F)**	**T_{Hot} (°F)**
Best-Estimate Flow							
0	0	0-12	0-68.5 Note(1)	0	Note(1)	425.5	Note(1)
15	24	47.7	280.2	31.7	528.5	543.3	558.2
50	80	75.6	443.7	66.5	512.2	543.3	574.4
75	120	88.9	521.6	84.6	503.8	543.3	582.9
100	160	100	587.0	99.8	496.6	543.3	590.1
Minimum Design Flow							
100	160	91.7	538.5	107.60	487.4	538.7	590.1
Maximum Design Flow							
100	160	112.5	660.5	89.65	507.8	548.9	590.0

Note (1): When core decay heat is not available as a heat source, the module heatup system provides the driving force for natural circulation flow. Flow rate will vary as a function of module heatup system performance, steam generator operation and RCS temperature. A typical hot zero power temperature and range of the steady state best-estimate flow rates are identified.

Figure 5.1-1: NuScale Power Module Major Components

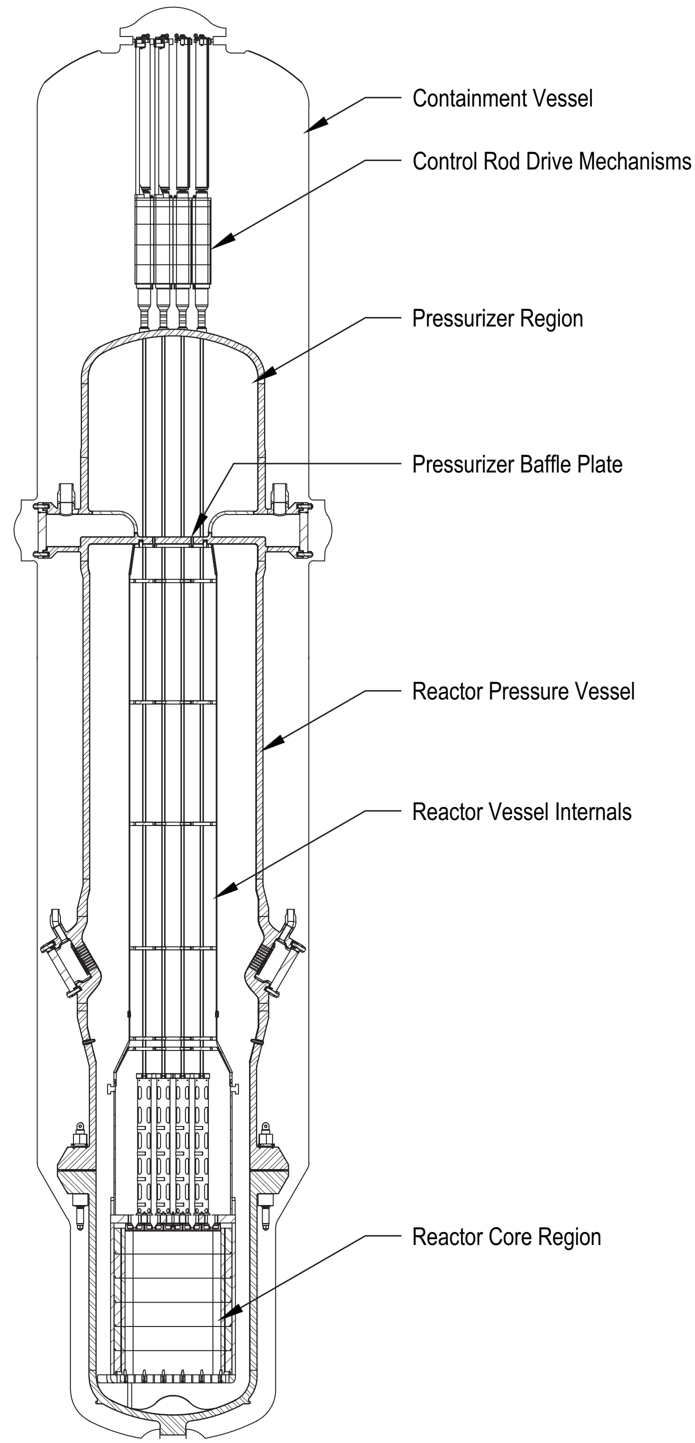


Figure 5.1-2: Reactor Coolant System Simplified Diagram

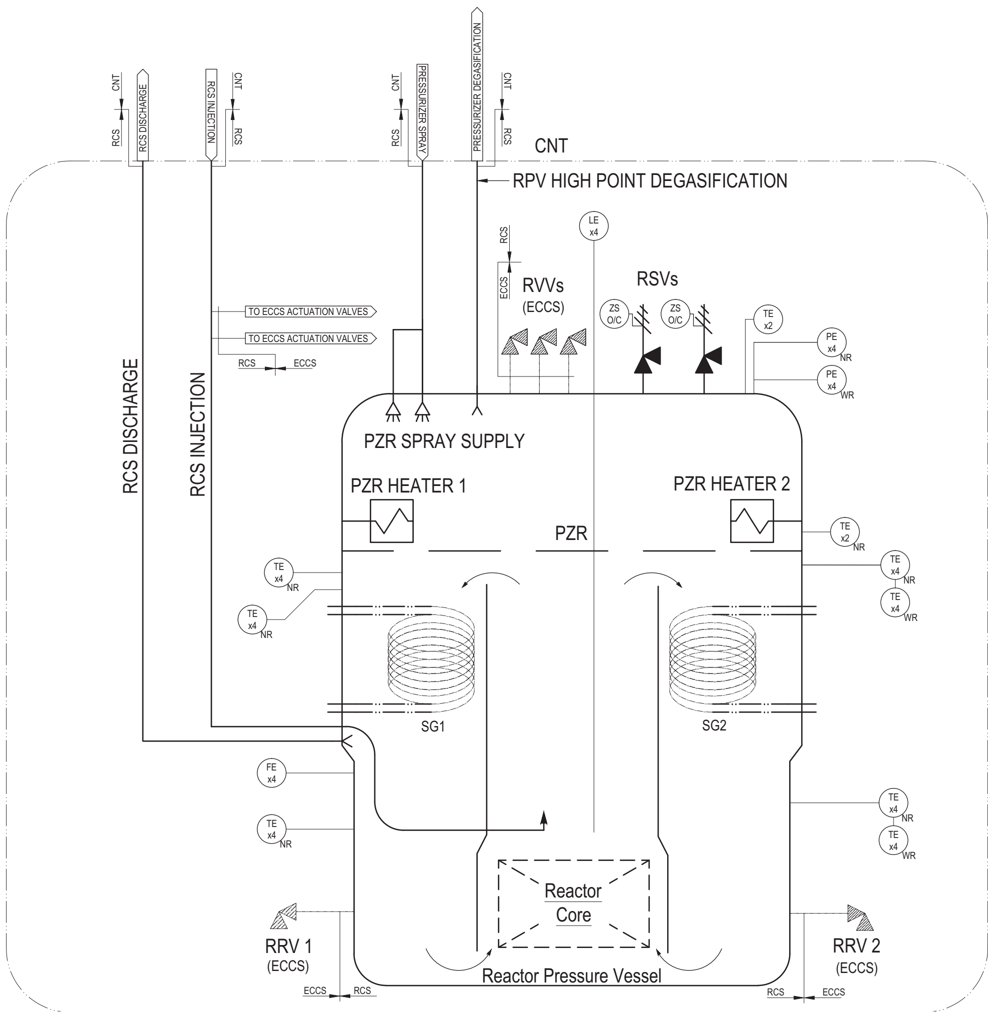
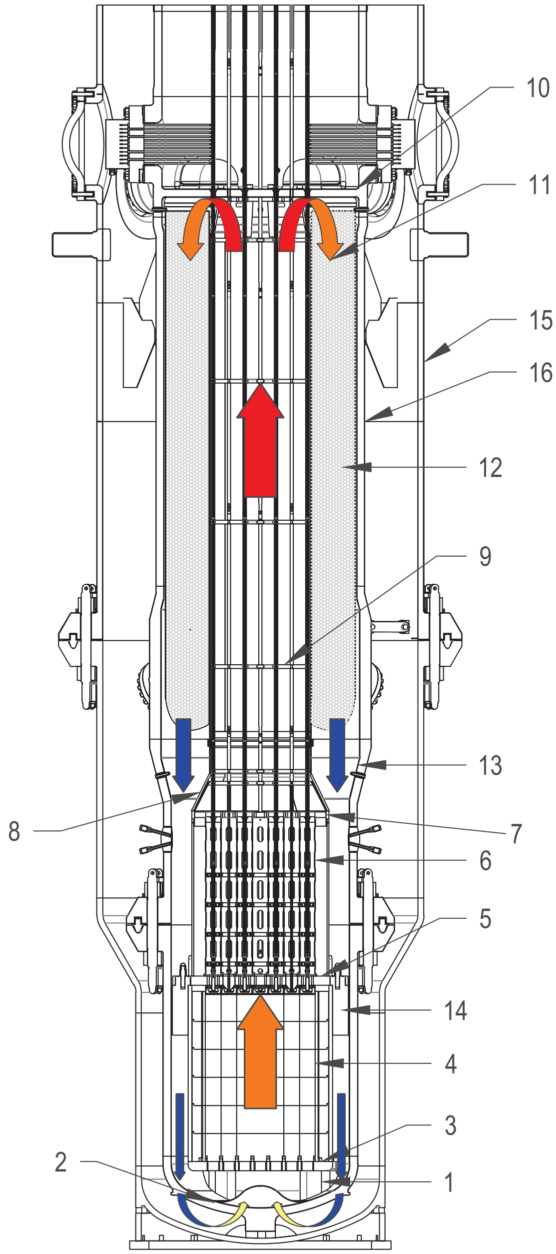


Figure 5.1-3: Reactor Coolant System Schematic Flow Diagram



No.	Stage
1	Core support blocks in downcomer
2	Downcomer to lower plenum turn
3	Lower core plate
4	Core
5	Upper core plate
6	Control rod assembly guide tubes
7	Control rod assembly guide tube support plate
8	Riser transition
9	Control rod drive shaft support
10	Pressurizer baffle
11	Upper riser turn to annulus
12	Downcomer through steam generator
13	Downcomer transition
14	Upper core support blocks
15	Containment vessel
16	Reactor vessel

5.2 Integrity of Reactor Coolant Boundary

The design features of each NuScale Power Module (NPM) are provided to maintain the integrity of the reactor coolant pressure boundary (RCPB) for the design life of the plant. The RCPB for each NPM is consistent with the RCPB definition provided in 10 CFR 50.2 and includes the pressure retaining components that are part of the reactor coolant system (RCS) up to and including:

- the outermost containment isolation valve (CIV) in system piping that penetrates the containment vessel (CNV)
- the reactor safety valves (RSVs)
- the emergency core cooling system (ECCS) reactor vent valves (RVVs) and reactor recirculation valves (RRVs)

For each NPM, the RCS piping that forms the RCPB penetrates both the reactor pressure vessel (RPV) and the CNV up to the outermost CIV. The RCS piping does not terminate inside the CNV.

The portions of the RCS that form the RCPB include the RPV shell, integral pressurizer (PZR) volume, RPV penetrations, several CNV nozzles and their safe ends, tubes of the steam generators (SGs), integral steam plenums and feed plenums, and pressure-retaining portions of the RSVs.

The systems and components connected to the RCS that are part of the RCPB are:

- pressure housing of the control rod drive mechanisms (CRDMs) described in Section 4.6.
- RCS injection and discharge, PZR spray, and high point degasification piping up to the outermost CIVs that connect the NPM to the chemical and volume control system (CVCS), described in Section 5.4.2.
- PZR heater bundles described in Section 5.4.5.
- RVVs and RRVs and the associated actuator assemblies described in Section 6.3.

The RPV, described in Section 5.3, is the primary component of the RCS and RCPB for each NPM. Section 3.9 describes the design transients, loading combinations, stress limits, evaluation methods used in the design and fatigue analyses of RCPB components, and design information used to support the conclusion that the RCPB integrity is maintained. The components of the RCPB are designed, constructed, and maintained commensurate with quality standards that ensure overpressure protection of the RCS.

The RCPB include the RCS injection and discharge piping that interfaces with the CVCS up to the outermost CIV installed on the top of each NPM. A summary discussion of containment isolation system is provided in Section 6.2.4. With respect to the NuScale design, compliance with and the applicability of 10 CFR 50, Appendix A, General Design Criteria (GDC) 55 and 57 is addressed in Section 3.1.

5.2.1 Compliance with Codes and Code Cases

5.2.1.1 Compliance with 10 CFR 50.55a

Each of the NPMs meet the relevant requirements of the following regulations:

- 10 CFR 50.55a - The RPV and pressure retaining components associated with the RCPB are designed, fabricated, constructed, tested, and inspected as Class 1 in accordance with Section III, of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC) and meet the applicable conditions promulgated in 10 CFR 50.55a(b).
- 10 CFR 50, Appendix A, GDC 1 and 30 - The RPV and pressure retaining components associated with the RCPB are designed, fabricated, and tested as Class 1 to the highest quality standards in accordance with Quality Assurance Program described in Chapter 17.

The RCS injection and discharge piping that connects to the CVCS up to and including the associated isolation valves is designed as Class 1 in accordance with the ASME BPVC, Section III. The RCS piping interfacing with the CVCS from the outermost CIVs to the NPM flange connections is not part of the RCPB and is designed as Class 3 in accordance with ASME BPVC, Section III. Also, systems other than the CVCS that connect to the RCS have required isolation and are not classified as RCPB. A listing of the RCPB pressure retaining components and the Nuclear Regulatory Commission (NRC) quality group classification is provided in Table 3.2-1.

The ASME BPVC of record for the NuScale design certification of the NPMs is the ASME BPVC, 2013 Edition with no Addenda. The 2013 Edition of the ASME BPVC, 2013 Edition, as endorsed by the ASME and promulgated in the 2015 rulemaking proposing to amend 10 CFR 50.55a (80 FR 56820), meets the requirements of ASME BPVC editions specified in 10 CFR 50.55a(a)(1) and Regulatory Guides (RGs) 1.84, Revision 36, and 1.147, Revision 17.

The application of the ASME BPVC Section XI inservice inspection (ISI) requirements for Quality Group A systems and components (ASME BPVC Class 1) are described in Section 5.2.4. The RCPB does not include Quality Group B or C components. The ASME BPVC Section XI ISI requirements for Quality Groups B and C systems and components (ASME BPVC Class 2 and 3) are described in Section 6.6.

Operational and maintenance inservice testing codes, standards, and guides for the NPMs design are in accordance with the ASME Operational and Maintenance (OM) Code OM-2012, "Operation and Maintenance of Nuclear Power Plants," as allowed by 10 CFR 50.55a(a)(1). ASME OM-2012, as endorsed by the ASME and promulgated in the 2015 rulemaking proposing to amend 10 CFR 50.55a (80 FR 56820), meets the requirements of ASME OM Code editions specified in 10 CFR 50.55a(a)(1) and RG 1.192, Revision 1. Use of ASME OM Code editions and addenda issued subsequent to the design certification is permitted or required based on the provisions in the design certification. If an ASME OM Code edition or addenda dated later than ASME OM-2012 edition is used, these later ASME OM Code editions and addenda and associated code cases must be approved for incorporation by reference per 10 CFR 50.55a(a)(1) or authorized by the NRC pursuant to 10 CFR 50.55a(a)(3) and subject to applicable provisions of 10 CFR 50.55a(b). An ASME OM Code edition or addenda not endorsed by the NRC may be used pursuant to the requirements of 10 CFR 50.55a(z).

Section 3.9.6 describes the Inservice Test Program and compliance with 10 CFR 50.55a(f)(3)(iii)(B) and 10 CFR 50.55a(f)(3)(iv)(B).

5.2.1.2 Compliance with Applicable Code Cases

The ASME BPVC, Section III code cases used for design, fabrication, and construction are determined by those listed in the applicable ASME BPVC Edition specified in 10 CFR 50.55a(a)(1)(i) or Tables 1 and 2 of RG 1.84 pursuant to 10 CFR 50.55a(a)(3)(i) and subject to the applicable provisions of 10 CFR 50.55a(b). Code cases that are used and listed in Table 2 of RG 1.84 also meet the conditions established in the RG.

Section 5.2.4 and Section 6.6 provide a summary discussion of preservice and ISI examinations and procedures. The applicable ASME BPVC Section XI code cases used for preservice inspection and ISI are identified by the plant owner and determined by those listed in the applicable ASME BPVC Edition specified in 10 CFR 50.55a(a)(1)(ii) or Tables 1 and 2 of RG 1.147 pursuant to 10 CFR 50.55a(a)(3)(ii) and subject to the applicable provisions of 10 CFR 50.55a(b). Code cases that are used and listed in Table 2 of RG 1.147 also meet the conditions established in the RG.

The ASME OM code cases used for preservice testing and inservice testing are identified by the plant owner and determined by those listed in the applicable ASME OM Code Edition specified in 10 CFR 50.55a(a)(1)(iv) or Tables 1 and 2 of RG 1.192 pursuant to 10 CFR 50.55a(a)(3)(iii) and subject to the applicable provisions of 10 CFR 50.55a(b). Code cases that are used and listed in Table 2 of RG 1.192 also meet the conditions established in the RG.

Table 5.2-1, "ASME Code Cases," provides a consolidated list of the specific code cases used in the NPM RCPB design that are not addressed in ASME BPVC 2013 Edition. Conditionally acceptable ASME code cases listed in Table 5.2-1 are subject to the applicable conditions specified in Table 2 of RG 1.84. Other acceptable and conditionally acceptable ASME code cases listed in RGs 1.84, 1.147, and 1.192 in effect at the time of the Design Certification and listed in RG revisions issued subsequent to the Design Certification may be used for RCPB components. ASME code cases listed in RG 1.193, Revision 4, are not used unless authorized by the NRC pursuant to the requirements of 10 CFR 50.55a(z).

COL Item 5.2-1: Not used.

5.2.2 Overpressure Protection

Each NPM is provided with overpressure protection features to protect the RCPB, including the primary side of auxiliary systems connected to the RCS, and the secondary side of the SGs from overpressurization.

Integrated overpressure protection is provided for the RCPB by two ASME BPVC Section III safety valves during normal operations and anticipated operational occurrences (AOOs). Integrated overpressure protection is provided for the secondary side components with the same design pressure as the RCPB by system design that does not exceed the ASME BPVC service limits during normal operations and AOOs. The low temperature overpressure protection (LTOP) system consists of the RVVs and provides overpressure protection during low temperature conditions.

Two pilot-operated RSVs are installed above the pressurizer volume on the top of the RPV head to provide overpressure relief for the RCS. These valves relieve the RCS pressure directly into containment. Structural design and valve qualification information related to the RSVs is provided in Section 5.2.2.4.

During NuScale Power Module startup and shutdown conditions with the module at low temperature conditions and the RPV not vented, LTOP is provided by the RVVs to prevent exceeding the maximum allowable pressure. Three RVVs are connected to the RPV above the PZR volume and discharge steam and water directly into containment. A temperature dependent pressure setpoint is provided when RPV temperature is below the LTOP enabling temperature. Upon LTOP actuation by the module protection system logic, the RVVs open to limit RCS pressure below the maximum allowable pressure.

Further description of the qualification, design, and operation of the RVVs, including the actuators, is provided in Section 6.3.

5.2.2.1 Design Bases

Overpressure protection for the RCPB is provided to ensure design pressure conditions are not exceeded during the normal range of operations, including AOOs in accordance with the requirements of 10 CFR 50, Appendix A, GDC 15. The overpressure protection system is designed with sufficient capacity to prevent RCPB pressure from exceeding 110 percent of design pressure during normal operations and AOOs. The overpressure protection system is able to perform its function assuming a single active failure and a concurrent loss of normal AC power.

The overpressure protection system for the secondary system ensures the ASME BPVC service limits are not exceeded during specified service conditions.

Overpressure protection provided by the RSVs is in accordance with the requirements of ASME BPVC, Section III, Articles NB-7000 for the RCPB and NC-7120(b) for the secondary system piping associated with the SGs and the DHRS that extends from the RPV to the secondary main steam isolation valves (MSIVs) and the feedwater regulating valves (FWRVs).

The CVCS, which is normally connected to the RCS, is isolated from the RCS following a containment isolation actuation as described in Section 6.2.4 and Section 7.1. During an operational RCS pressure transient that does not result in isolation of the CVCS from the RCS, CVCS overpressure protection is provided by the RPV integral PZR, CVCS design, and relief valves as described in Section 9.3.4.

Overpressure protection for the RCPB is also provided during low temperature conditions with sufficient margin to ensure the pressure boundary behaves in a non-brittle manner and the probability of a rapidly propagating fracture is minimized consistent with the requirements of 10 CFR 50, Appendix A, GDC 31.

The LTOP system design provides sufficient capacity to prevent RCPB pressure from exceeding the pressure-temperature (P-T) limits derived from 10 CFR 50 Appendix G when below the LTOP system enable temperature such that RPV pressure is maintained below brittle fracture limits during operating, maintenance, testing or postulated accident conditions.

During power operation, normal pressure control is provided by the PZR surge volume with sufficient capacity to preclude actuation of the RSVs during normal operational transients. Protection is provided during the following operating conditions:

- The reactor is operating at the licensed core thermal power level.
- System and core parameters values are within normal operating range that produce the highest anticipated pressure.
- Components, instrumentation, and controls function normally.

The NPM is designed to achieve safe shutdown conditions without reliance on pressure control by PZR heaters or PZR spray flow. Additionally, the thermal hydraulic analysis demonstrates that the PZR volume is adequate to accept the in-surge from a loss of load transient without liquid or two-phase flow reaching the RSVs. Further description of the PZR is provided in Section 5.4.5.

5.2.2.2 Design Evaluation

Overpressure protection for the RPV is provided by two RSVs during power operations and the RVVs provide overpressure protection during operations at low temperature conditions. The RSVs also provide external overpressure protection for the SG tubing and plenums. Additionally, the RSVs provide overpressure protection for piping external to the RPV that forms part of the RCPB (e.g., RCS injection, discharge, degasification, and pressurizer spray piping up to and including the outermost CIVs; ECCS valve pilot actuator piping, and several CNV nozzles and their safe ends).

A thermal relief valve provides overpressure protection for the control rod drive system cooling piping during a containment isolation event. Additional information regarding the control rod drive system is provided in Section 4.6.

Integrated overpressure protection for the secondary side components with design pressure equal to RCPB design pressure is provided by system design that does not exceed the ASME BPVC service limits during normal operation or during transients, thereby precluding the need for pressure relieving devices as indicated in ASME BPVC, Section III, Paragraph NB-7120(c) and NC-7120(b). Secondary systems with the same design pressure as the RCPB include the SG system, the decay heat removal system (DHRS), the steam and feedwater portions of the containment system, the portion of the condensate and feedwater system downstream of the FWRVs, and the portion of the main steam system upstream of the secondary MSIVs. Design and service limits for these systems are described in Section 3.9. Under normal operating conditions and pressure transients, internal pressure limits on these systems are not exceeded because the design pressure is equivalent to the design pressure of the RCPB. Overpressure protection for the portion of the main steam system downstream of the secondary MSIVs is discussed in Section 10.3. In the event of a SG tube failure accident, overpressure protection for SG internal pressure is provided by the primary system RSVs.

During shutdown conditions, thermal relief valves provide overpressure protection for the secondary side of the SGs, feedwater and steam piping in containment, and the DHRS when the secondary system is water solid and the containment is isolated. The thermal relief valves provide investment protection for the secondary system components during shutdown conditions and are not credited for safety-related overpressure protection for these systems during operation. Additional information regarding the thermal relief valves is provided in Section 5.4.

5.2.2.2.1 Overpressure Protection During Power Operations

The main design function of the RSVs is to provide overpressure protection for the RPV in accordance with the requirements of the ASME BPVC, Section III, Article NB-7000 and 10 CFR 50, Appendix A, GDC 15. The RSVs are designed as part of the RCPB, are bolted via flange to a nozzle safe end directly to the RPV head, and the setpoint of each valve is designed to actuate the associated RSV on RCS high pressure to allow flow directly to containment.

The RSVs are designed as Seismic Category I components, Quality Group A, constructed in accordance with ASME BPVC, Section III, Subsection NB.

Overpressure protection during power operation or an AOO is provided for the RCS by the RSVs. The AOOs analyzed, which could lead to overpressure of the RCPB, include:

- loss of load
- turbine trip with bypass
- turbine trip without bypass
- loss of condenser vacuum
- inadvertent MSIV closure
- steam pressure regulator failure closed
- loss of normal AC power
- loss of feedwater
- inadvertent operation of the DHRS

These AOOs are further described in DCD Chapter 15 and include plant initial conditions and system parameters, assumptions used in the analysis, and a list of systems and equipment assumed to operate, reactor trip signals, and sensitivity of the system's performance to variations in the event conditions, parameters, and characteristics.

A turbine trip at full power without bypass capability is the most severe AOO and is the bounding event used in the determination of RSV capacity and the RPV overpressure analyses. The RCS and the PZR steam space are sized to avoid an RSV lift during normal operational transients at full power conditions, with system and core parameters within normal operating range, that produce the highest RPV pressure. In the event of a safety valve lift, the size of the PZR steam space is sufficient to preclude liquid discharge.

The RSVs are designed with sufficient capacity to prevent RCPB pressure from exceeding 110 percent of design pressure under normal and abnormal conditions. The analytical model used for the analysis of the overpressure protection system and the basis for its validity is provided in NuScale Topical Reports TR-0516-49416, "Non-LOCA Transient Analysis Methodology," (Reference 5.2-1) and TR-0516-49422, "LOCA Evaluation Model" (Reference 5.2-2). The analysis maximizes the net heat input into the RCS and maximizes the coefficient of thermal expansion of the RCS coolant to determine the volumetric capacity of a single RSV. The RSV volumetric capacity considers the largest surge rate into the PZR.

5.2.2.2.2 Low Temperature Overpressure Protection System

Overpressure protection during low temperature conditions is provided by the RVVs, which are part of the RCPB and are designed in accordance with ASME BPVC, Section III, Subsection NB.

An RCS overpressurization during low temperature conditions could occur due to equipment malfunctions or operator error that results in excessive heat or inventory being added to the RCS, including inadvertent energization of the PZR heaters, inadvertent operation of the module heatup system, or excessive CVCS makeup. Increased RCS inventory events and inadvertent operation of the module heatup system are terminated by isolation of RCS injection line on high PZR water level thereby precluding RCS inventory solid conditions from challenging the integrity of the RCPB at low temperature conditions. Operability and testing requirements associated with the automatic isolation of the RCS injection piping on high PZR water level are provided in the plant technical specifications. The spurious actuation of the PZR heaters is the limiting RCS cold overpressurization event.

The RVVs are designed with sufficient capacity to prevent RCPB pressure from exceeding the limiting pressure when below the LTOP enabling temperature such that an RPV is maintained below brittle fracture stress limits during operating, maintenance, testing or postulated accident conditions. The variable LTOP limit is determined as a function of RCS cold temperature (i.e., temperature in the downcomer at the SG outlet). The selected LTOP pressure setpoint is a function of the cold temperature. Table 5.2-10 provides the LTOP pressure setpoint using linear interpolation between values. Figure 5.2-4 provides a graph of the LTOP variable setpoint. LTOP is enabled when the RCS cold temperature is less than or equal to 318 degrees F. The RVVs are part of the RCPB and are capable of opening during startup and shutdown discharging directly from the RCS to containment to provide the LTOP function.

Selection of the LTOP setpoint considers the worst case low temperature overpressure transient, which is the spurious actuation of the PZR heaters while below the LTOP enabling temperature. The LTOP analysis assumes a bounding maximum PZR heater total power output of 880 kW with an additional heat input of 2 MW from core decay heat. An LTOP pressurization case demonstrates that the RVVs open before RCS pressure exceeds the low temperature pressure limit. This case assumes initial conditions that maximize the rate of PZR level increase as it approaches a water solid condition, thus maximizing the pressurization rate. A 10 second delay is assumed before the RVVs open to maximize the pressure increase. The LTOP setpoint includes the following margin: pressure and temperature uncertainty; the difference in elevation between the pressure sensing instrumentation and the bottom of the RPV; the potential difference in temperature between downcomer regions; the maximum delay in RVV opening; delay in sensor response time; and module protection system processing time.

As PZR level nears 100 percent, LTOP analysis shows pressure increasing rapidly and exceeding the LTOP pressure setpoint. During the valve opening delay, PZR pressure continues to increase followed by opening of the RVV. The analysis results indicate the peak pressure remains below the brittle fracture stress limit.

COL Item 5.2-2: A COL applicant that references the NuScale Power Plant design certification will provide a certified Overpressure Protection Report in compliance with American Society of Mechanical Engineers Boiler and Pressure Vessel Code Section III Subarticles NB-7200 and NC-7200 to demonstrate the reactor coolant pressure boundary and secondary system are designed with adequate overpressure protection features, including low temperature overpressure protection features.

5.2.2.3 Piping and Instrumentation Diagram

Figure 5.1-2 provides the RCS piping and instrument diagram and illustrates the design configuration of the RSVs and RVVs showing the number and location with respect to the RPV.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Reactor Safety Valves

The RSVs are redundant, safety-related, Seismic Category I, Quality Group A components designed to maintain pressure below 110 percent of design pressure, 2310 psia. Each valve is sized to provide 100 percent of the required relief capacity.

The RSV design information is provided in Table 5.2-2, and materials of the RSV components are provided in Table 6.1-3. The RSV pressure boundary design life is for a service life of 60 years. Each RSV is a pilot operated relief valve designed in accordance with the requirements of ASME BPVC, Section III, Subsubarticle NB-7520. The valve is designed to allow RCS pressure routed to a chamber located above the pilot disc where it expands the pilot valve bellows and seats the pilot disc. Relief pressure is determined by the spring pre-load of the pilot valve and the main valve closing spring pressure. A simplified diagram of the RSV and associated pilot valve is provided in Figure 5.2-1 and Figure 5.2-2. RSVs are designed for 300 cycles over the design life. Environmental qualification information associated with the RSVs is provided in Section 3.11.

5.2.2.4.2 Reactor Vent Valves

Three RVVs are safety-related, Seismic Category I, Quality Group A components constructed in accordance with ASME BPVC, Section III, Subsection NB, each designed with sufficient relief capacity to prevent brittle fracture stress limits being exceeded on the RPV and pressure-retaining components associated with the RCPB when operating at low temperature conditions.

The trip and reset valves for the RVVs are solenoid pilot valves constructed in accordance with ASME BPVC, Section III, Subsection NB. The pilot actuators are mounted on the exterior of the CNV. To minimize the probability of an inadvertent opening of the RVVs when operating at power, an inadvertent actuation block feature in the RVV actuators prevent valve opening when at normal operating RCS pressure. The inadvertent actuation block arming setpoint is above the limiting RPV pressure at LTOP conditions and, as such, will not prevent LTOP actuation of the RVVs when LTOP enabling setpoint is reached. Section 6.3.2 provides a detailed description of the RVVs and valve actuators.

Three RVVs, associated actuators, and controls ensure LTOP protection is maintained assuming a single active component failure. The RVVs are designed with sufficient pressure relief capacity to accommodate the most limiting single active failure assuming the most limiting allowable operating condition and system configuration.

Further description of the design and operation of the RVVs is covered in Section 6.3.2. Environmental qualification information associated with the RVVs is provided in Section 3.11.

5.2.2.5 Mounting of Pressure-Relief Devices

The RSVs are bolted to flanges mounted on the RPV head, to allow for periodic removal for inspection and testing. Access to the RSVs is provided by a manway on the containment upper head.

The RRVs and RVVs are bolted directly to the reactor vessel nozzles. Further description of the design of the RRVs and RVVs is covered in Section 6.3.2.

5.2.2.6 Applicable Codes and Classification

The RSVs and RVVs are designed in accordance with ASME BPVC, Section III, Subarticle NB-3500 and function to satisfy the overpressure protection criteria described in ASME BPVC Section III, Article NB-7000. The applicable design code edition is described in Section 5.2.1 and Section 3.2 describes the classifications applicable to overpressurization equipment and components.

5.2.2.7 Material Specifications

Material specifications for the RSVs and the RVVs are addressed in Section 6.1.

5.2.2.8 Process Instrumentation

Direct position indication for each RSV and RVV is provided in the control room pursuant to the requirement of 10 CFR 50.34(f)(2)(xi) promulgating Three Mile Island action plan recommendation Item II.D.3. Due to the design of the NPM, RCS leakage into the containment atmosphere is conservatively classified as unidentified leakage, including the leakage from these valves.

Detection of leakage from the reactor vessel to the containment vessel is discussed in Section 9.3.6.3.

5.2.2.9 System Reliability

The RSVs and RVVs are designed, tested and inspected to ASME BPVC, Sections III and XI criteria. ASME BPVC safety and relief valves have demonstrated a high degree of reliability over their many years of service in the nuclear industry. Functional qualification of the RSVs and RVVs is performed in accordance with ASME QME-1 as endorsed by RG 1.100. The inservice testing and inspection of the safety and vent valves provides reasonable assurance of continued reliability and conformance.

The RSVs are considered passive devices. The metal bellows, spring operated pilot valve arrangement is designed in accordance with ASME BPVC, Section III, Subparagraph NB-7511.1 requirements. The design of the mechanical operation of the pilot valve is for opening the main valve with a large differential pressure across the main valve disk to reliably relieve the PZR pressure. Redundant RSVs provide additional reliability that the system will adequately respond to overpressure events.

The reliability of the RVVs is discussed in Section 6.3.2.

5.2.2.10 Testing and Inspection

Testing and inspection of overpressure protection equipment is conducted in accordance with accepted industry standards including Sections III and XI of the ASME BPVC, Mandatory Appendix I of the ASME OM Code, and the requirements of 10 CFR 50.34(f)(2)(x) promulgating Three Mile Island action plan recommendation Item II.D.1.

Overpressure protection surveillance testing requirements for normal and low temperature operating conditions are addressed in plant technical specifications.

The RSVs are included in the plant inservice testing program. A position verification test is performed for each valve every 24 months during refueling conditions in accordance with ASME Code OM-2012, Division 1, Subarticle ISTC-3700 and a set pressure test is performed every 5 years in accordance with ASME Code OM-2012, Division 1, Mandatory Appendix I, Paragraphs I-1320 and I-7310.

Sections 6.6, 14.2, and 3.9.6 provide additional information on testing and inspection of the overpressure protection components.

5.2.3 Reactor Coolant Pressure Boundary Materials

The RCPB materials, including weld materials, conform to fabrication, construction, and testing requirements of ASME BPVC, Section III, Subsection NB requirements and the materials selected for fabrication of the RCPB comply with the requirements of ASME BPVC, Section II. Details of the materials conformance for the RPV are provided in Section 5.3.

The RCPB materials comply with the relevant requirements of the following regulations:

- 10 CFR 50, Appendix A
  - GDC 1 and 30 - The RPV materials and pressure retaining component materials associated with the RCPB are designed, fabricated, and tested as Class 1 to the highest quality standards in accordance with the Quality Assurance described in Chapter 17.
  - GDC 4 - The RPV and pressure retaining components associated with the RCPB are designed and fabricated to be compatible with the environmental conditions of the reactor coolant and containment atmosphere.
  - GDC 14 and 31 - The RPV and pressure retaining components associated with the RCPB are designed and fabricated with sufficient margin to ensure the RCPB behaves in a non-brittle manner and to minimize the probability of rapidly propagating fracture and gross rupture of the RCPB.
- Criterion XIII of 10 CFR 50, Appendix B - Measures are established to control the on-site cleaning of RPV and pressure retaining components associated with the RCPB during construction.

COL Item 5.2-3: Not used.

- Appendix G to 10 CFR 50 - The RPV ferritic pressure retaining and integrally attached materials are tested and meet applicable fracture toughness acceptance criteria.

5.2.3.1 Material Specifications

The materials for the Class 1 components and supports that comprise the RCPB, including the RPV and SGs, are provided in Table 5.2-4. Table 5.2-4 also includes materials and specifications associated with the RPV attachments and appurtenances. The table lists the grade or type, as applicable, of the ferritic low allow steels, austenitic stainless steels, and nickel-based alloys specified for the RCPB. Except where noted in Table 5.2-4, the final metallurgical condition is provided in the associated ASME BPVC material specification. Further discussion of the materials associated with the RPV is provided in Section 5.3.

The RCPB surface materials normally in contact with reactor coolant or in contact with pool water during refueling, including welds, are austenitic stainless steel or nickel-based alloy.

Processing and welding of unstablized American Iron and Steel Institute Type 3XX series austenitic stainless steels for pressure retaining components comply with RG 1.44, Revision 1, to prevent sensitization caused by chromium depletion at the grain boundaries during welding and heat treatment operations. For unstablized American

Iron and Steel Institute Type 3XX series austenitic stainless steel subjected to sensitizing temperatures subsequent to solution heat treatment, the carbon content is limited to no more than 0.03 weight percent (wt%).

Nickel-based Alloy 690 is used as a base metal in the RCPB components and structures along with Alloy 52/152 cladding and weld metals and similar alloys developed for improved weldability. Alloy 690 and 52/152 have a high resistance to general corrosion, high resistance to fast fracture, and superior tensile properties at elevated temperature. Steam generator tubes use Alloy 690 in the thermally treated condition. Alloy 600 base metal and Alloy 82/182 cladding and weld metal are not used in the RCPB design.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Reactor Coolant Chemistry

The RCS water chemistry for each NuScale Power Module is controlled to minimize corrosion of RCS surfaces and to minimize corrosion product transport during normal operation. These objectives ensure the integrity of reactor pressure boundary materials, the integrity of the fuel cladding, fuel performance by limiting cladding corrosion, and the minimization of radiation fields. Accordingly, alkaline-reducing water chemistry is maintained during power operation. The coolant is routinely sampled and analyzed to verify its chemical composition.

The CVCS provides the means for chemical addition to the primary coolant via the RCS injection line and removal of chemicals, suspended solids, and impurities by the CVCS purification systems via the RCS discharge line. Chemical concentrations and impurities are also reduced by diluting the primary coolant with RCS injection flow.

For reactivity control, boric acid is added as a soluble neutron poison and is adjusted as needed for reactivity control to compensate for changes in fuel reactivity over the lifetime of the fuel.

Lithium hydroxide enriched with lithium-7 isotope is added to the reactor coolant through the charging flow of the CVCS. Lithium is removed from the RCS through the use of the CVCS delithiating ion exchanger to maintain the pH level within the required range. Lithium hydroxide is chosen for its compatibility with boric acid, stainless steel, zirconium alloys, and nickel-base alloys. The primary coolant pH and lithium concentration are maintained within the plant specific pH program in accordance with the recommendations of the fuel vendor and the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) Primary Water Chemistry Guidelines (Reference 5.2-3).

Dissolved hydrogen is added during operation to maintain a reducing environment in the reactor coolant. Hydrogen is chosen for its compatibility with an aqueous environment and its ability to suppress oxygen generated by the radiolysis of water and oxygen introduced into the RCS with makeup water. Dissolved hydrogen is added to the reactor coolant by direct injection of high pressure gaseous hydrogen into the CVCS charging flow. Hydrazine is added to scavenge dissolved oxygen at low temperature during startup.

The quality of the chemicals and the makeup water added to the reactor coolant are controlled to limit potential contamination. Reactor coolant chemistry parameters and impurity limitations monitored during power operations, including the parameters listed in Table 5.2-5, conform to the limits specified the EPRI PWR Primary Water Chemistry Guidelines and the RG 1.44, Revision 1, limits also specified in Table 5.2-5. Zinc is added to the primary system in order to reduce radiation levels in plant maintenance areas and reduce primary water stress-corrosion cracking (PWSCC) initiation rates.

The water chemistry program is based on industry guidelines as described in EPRI Technical Report 3002000505, Pressurized Water Reactor Primary Water Chemistry Guidelines, (Reference 5.2-3). The program includes periodic monitoring and control of chemical additives and reactor coolant impurities listed in Table 5.2-5. Detailed procedures implement the program requirements for sampling and analysis frequencies and corrective actions for control of reactor water chemistry.

The frequency of sampling water chemistry varies (e.g., continuous, daily, weekly, or as needed) based on plant operating conditions and the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range and within the time period specified in the EPRI water chemistry guidelines. Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants to within the specified range. Chemistry procedures will provide guidance for the sampling and monitoring of primary coolant properties.

Refueling operations will require the NuScale Power Module to be isolated, disconnected from the attached systems, and transported to the refueling pool for disassembly and refueling. The pool water will be purified by the pool cleanup system to ensure impurity levels in the pool water meet the impurity levels (i.e. chloride, fluoride, and sulfate) specified for reactor coolant system cold shutdown in the EPRI PWR Primary Water Chemistry Guidelines (Reference 5.2-3).

COL Item 5.2-4: A COL applicant that references the NuScale Power Plant design certification will develop and implement a Strategic Water Chemistry Plan. The Strategic Water Chemistry Plan will provide the optimization strategy for maintaining primary coolant chemistry and provide the basis for requirements for sampling and analysis frequencies, and corrective actions for control of primary water chemistry consistent with the latest version of the Electric Power Research Institute Pressurized Water Reactor Primary Water Chemistry Guidelines.

COL Item 5.2-5: A COL applicant that references the NuScale Power Plant design certification will develop and implement a Boric Acid Control Program that includes: inspection elements to ensure the integrity of the reactor coolant pressure boundary components for subsequent service, monitoring of the containment atmosphere for evidence of reactor coolant system leakage, the type of visual or other nondestructive inspections to be performed, and the required inspection frequency.

5.2.3.2.2 Compatibility of Construction Materials with Reactor Coolant

The RCPB ferritic low alloy steels used in pressure retaining applications have austenitic stainless steel cladding or Ni-Cr-Fe cladding on surfaces that are exposed to the reactor coolant. Low alloy steel forgings have an average grain size of five or finer in accordance with American Society for Testing and Materials standards. The cladding of ferritic type base material receives a post-weld heat treatment as required by ASME BPVC, Section III, Subsubarticle NB-4622.

The inside and outside surfaces of the RPV low alloy steels including RPV attachments and appurtenances in contact with reactor coolant, secondary water or pool water are clad with austenitic stainless steel or Ni-Cr-Fe. The austenitic stainless steel cladding on the inside surfaces is deposited with at least two layers; the first layer is Type 309L and subsequent layers are Type 308L. The austenitic stainless steel cladding on the outside surfaces is deposited with at least one layer of Type 309L. The Ni-Cr-Fe cladding is deposited with Alloy 52/152. Weld overlay cladding is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME BPVC, Section III, Subarticle NB-4300 and Section IX.

The through-holes in the baffle plate of the low-alloy steel, integral steam plenum for the twelve incore instrumentation guide tubes are sleeved with Alloy 690 inserts. Larger through-holes in the baffle plate for the CRDM shafts and holes for pressurizer insurge and outsurge flow, approximately two inches in diameter or greater, are cladded with austenitic stainless steel.

The use of cobalt based alloys is minimized and limits are established to minimize cobalt intrusion into the reactor coolant. Cobalt based alloys are used for hard surfacing and wear resistant parts in the CRDMs. Refer to Section 4.5 for additional details regarding the materials of the CRDMs. Low cobalt or cobalt-free alloys may be used for hardfacing and wear resistant parts in contact with the reactor coolant if their wear and corrosion resistance are qualified by testing.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

The fracture toughness properties of the RCPB components comply with the requirements of 10 CFR 50, Appendix G, "Fracture toughness requirements," and ASME BPVC, Section III, Subarticle NB-2300. Discussion of the fracture toughness requirements of the RPV materials are provided in Section 5.3.

5.2.3.3.2 Welding Control - Ferritic Materials

Welding of ferritic materials used for components of the RCPB is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME BPVC, Section III, Subarticle NB-4300 and Section IX.

Stainless steel corrosion resistant weld overlay cladding of low alloy steel components conforms to the requirements of RG 1.43, Revision 1. Controls to limit underclad cracking of susceptible materials also conform to the requirements of RG 1.43.

Prior to cladding, the surfaces to be clad are examined using magnetic particle or liquid penetrant tests in accordance with ASME BPVC Section III, Paragraphs NB-2545 or NB-2546, respectively.

Other than for austenitic stainless steel cladding of low alloy steel, electroslag welding is not used.

Controls for preheating and interpass temperatures to support welding of carbon and low alloy steel in the RCPB, including preheat for weld deposited cladding, conform to the requirements of ASME BPVC Section III, Division 1, Non-mandatory Appendix D and are specified in the welding procedure specification as required by ASME BPVC Section IX, Article V. Control of the preheat temperature for low alloy steel forgings is in accordance with the requirements of RG 1.50, Revision 1.

Procedure qualification records and welding procedure specifications used to support welding of low alloy steel welds in the RCPB are qualified per ASME BPVC Section III, Subarticle NB-4600 and Section IX. Welders and welding operators are qualified in accordance with ASME BPVC Section III, Subarticle NB-4300 and ASME Section IX. Controls imposed on welding ferritic steels under conditions of limited accessibility are in accordance with the recommendations RG 1.71, Revision 1.

Post weld heat treatment temperature of the RPV low alloy steel material is 1125 degrees F $\pm$ 25 degrees F. Alternative post weld heat treatment times and temperatures specified in Subparagraph NB-4622.4(c) of ASME BPVC Section III, Subsection NB are not used.

5.2.3.3.3 Nondestructive Examination of Ferritic Steel Tubular Products

The RCPB components do not contain ferritic steel tubular products. Nondestructive examination requirements associated with austenitic stainless steel tubular products are discussed in Section 5.2.3.4.5.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steels

5.2.3.4.1 Prevention of Sensitization and Intergranular Corrosion of Austenitic Stainless Steel

In aggressive environments, sensitized austenitic stainless steels are susceptible to intergranular corrosion. Grain boundary carbide sensitization occurs when metal carbides precipitate on the grain boundaries when the material is heated in the temperature range of 800 degrees F to 1500 degrees F.

Avoidance of sensitization and intergranular attack in unstablized Type 3XX austenitic stainless steels is accomplished by compliance with RG 1.44, Revision 1.

Austenitic stainless steel weld materials for RCPB are analyzed for delta ferrite content and limited to 5 FN to 20 FN in accordance with RG 1.31, Revision 4, and ASME BPV Code, Section III, Paragraph NB-2433.

The control of oxygen, chlorides, and fluorides in the reactor coolant during normal operation further minimizes the probability of stress corrosion cracking of unstabilized austenitic stainless steels. The primary water chemistry is maintained as described in Section 5.2.3.2. Additional information regarding the CVCS and the process for controlling RCS water chemistry is provided in Section 9.3.4.

The use of hydrogen in the reactor coolant inhibits the presence of oxygen during operation. Gaseous argon may also be added to reactor coolant at the same location as the hydrogen injection tee, if required, to support primary to secondary leakage controls. The effectiveness of these controls has been demonstrated by test and operating experience.

Precautions are taken to prevent the intrusion of contaminants into the system during fabrication, shipping, and storage.

Use of cold worked austenitic stainless steel is avoided to the extent practicable during fabrication of RCPB components. Cold worked austenitic stainless steel with a material yield strength greater than 90,000 psi, as determined by the 0.2 percent offset method, is not used in the fabrication of RCPB components.

5.2.3.4.2 Cleaning and Contamination Protection Procedures

Cleaning of RCPB components complies with ASME NQA-1 requirements (Reference 5.2-5). The final cleanness of the RCPB internal surfaces meets the requirements for "Class B" of Subpart 2.1. The final cleanness of the RCPB external surfaces meets the requirements for “Class C” of Subpart 2.1.

Handling, storage, and shipping of RCPB components comply with ASME NQA-1-2008, Part I, Requirement 13. Packaging, shipment, handling, and storage of RCPB components meet the applicable requirements of ASME NQA-1a-2009, Part II, Subpart 2.2 (Reference 5.2-5).

Austenitic stainless steel materials used in the fabrication, installation, and testing of nuclear steam supply components and systems are handled, protected, stored, and cleaned according to recognized and accepted methods that are designed to minimize contamination which could lead to stress corrosion cracking.

Procedures provide cleanliness controls during the various phases of manufacture and installation including final flushing. The suppliers implement a written cleanliness control plan prior to and during manufacturing and assembly of components and continues until components are sealed for shipment. The cleanliness control plan includes specific provisions for:

- maintenance of cleanliness
- controls to prevent foreign material from being introduced into the hardware
- water purity control
- controls to prevent detrimental material from contacting hardware
- support system cleanliness and inspection
- use of temporary plugs or seals to prevent entry of foreign material and objects and, as practical, prevent mechanical damage
- use of stickers or other devices identifying cleanliness control requirements, affixed to temporary plugs and seals in such a manner that removal of the plug or seal cannot be accomplished without breaking the sticker
- detection and removal of foreign objects
- maintenance of cleanliness immediately prior to and during welding, brazing, and heat treating
- tools and loose parts accountability
- complete removal of temporary markings prior to heating, welding, heat treating, assembly, or shipment

Controls are established to minimize the introduction of potentially harmful contaminants including chlorides, fluorides, and low melting point alloys on the surface of austenitic stainless steel components. In accordance with RG 1.44, cleaning solutions, processing equipment, degreasing agents, and other foreign materials are removed at any stage of processing prior to elevated temperature treatments. Acid pickling is avoided on stainless steel.

Use of abrasive work is minimized to avoid surface coldwork and contamination. Tools for abrasive work such as grinding, polishing, or wire brushing are not permitted to be contaminated by previous usage on carbon or low alloy steels or other non-corrosive resistant materials that could contribute to intergranular cracking or stress-corrosion cracking.

5.2.3.4.3 Compatibility of Construction Materials with External Reactor Coolant

The external surfaces of the RPV are clad with austenitic stainless steel. External surfaces of the RCPB do not contain exposed ferritic materials and are compatible with a borated water environment and resistant to general corrosion.

5.2.3.4.4 Control of Welding - Austenitic Stainless Steel

Welding is conducted utilizing procedures qualified according to the rules of ASME BPVC, Sections III, Subarticle NB-4300 and IX. Control of welding variables, as well as examination and testing during procedure qualification and production welding, is performed in accordance with ASME Code requirements.

Welders and welding operators are qualified in accordance with ASME Section IX and RG 1.71, Revision 1.

5.2.3.4.5 Nondestructive Examination for Austenitic Stainless Steel Tubular Products

Nondestructive examinations performed on austenitic stainless steel tubular products to detect unacceptable defects comply with ASME BPVC, Section III, Subsubarticles NB-2550 through NB-2570, and Section XI examination requirements. For Class 1 piping welds requiring an ultrasonic preservice examination, the welds meet the surface finish and marking requirements of ASME BPV Code, Section III, Subparagraph NB-4424.2.

5.2.3.5 Prevention of Primary Water Stress-Corrosion Cracking for Nickel-Based Alloys

Nickel-based alloy components in the RCS are protected from PWSCC by:

- using Alloy 690/152/52 in nickel-based alloy applications.
- controlled chemistry, mechanical properties, and thermo-mechanical processing requirements that produce an optimum microstructure for resistance to intergranular corrosion for nickel-based alloy base metal.
- limiting the sulfur content of nickel-based alloy base metal in contact with RCS primary fluid to maximum 0.02 wt%.

The nickel-based alloy materials that are used in the RCPB, including weld materials, conform to the fabrication, construction, and testing requirements of ASME BPVC Section III. Material specifications comply with ASME BPVC Section II Parts B and C. Welding of nickel-base alloys in the RCPB is performed in accordance with procedures qualified to the requirements of ASME BPVC, Section III, Subarticle NB-4300 and Section IX. Control of welding variables, as well as examination and testing during procedure qualification and production welding, are performed in accordance with ASME Code requirements. Welders and welding operators are qualified in accordance with ASME Section IX and RG 1.71, Revision 1.

Chemistry, mechanical properties, and thermo-mechanical processing requirements are controlled in nickel-based alloy base metal by solution annealing and by thermal treating to produce an optimum microstructure for resistance to intergranular corrosion.

EPRI Materials Reliability Program Reports MRP-111 (Reference 5.2-6) and MRP-258 (Reference 5.2-7) detail the Alloy 690, 52/52M, and 152 resistance to PWSCC. These documents conclude that Alloy 690 and its weld metals are highly corrosion resistant materials deemed acceptable for PWR applications. No signs of PWSCC in Alloy 690 materials have been observed in operating PWRs and Alloy 690 has proven resistant to PWSCC initiation in a wide variety of laboratory tests.

These EPRI reports provide a comprehensive summary of Alloy 690 stress corrosion cracking laboratory test data from simulated primary water environments which provides reasonable assurance of the high resistance to PWSCC for Alloy 690 and its weld metals.

5.2.3.6 Threaded Fasteners

Threaded fasteners used in the RPV main closure flange, PZR heater bundle closures, RCS piping flanges, and RSV flanges are nickel-based Alloy 718. Threaded fastener materials conform to the applicable requirements of ASME BPVC, Sections II and III and are selected for their compatibility with the borated water environment in the RCS and reactor pool water.

Section 3.13 provides further description of the design of threaded fasteners for the RPV and pressure retaining components including design requirements for the use of Alloy 718 for the mitigation of SCC.

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

Preservice and inservice inspection and testing of ASME BPVC Class 1 pressure-retaining components (including vessels, pumps, valves, bolting, and supports) within the RCPB are performed in accordance with ASME BPVC, Section XI pursuant to 10 CFR 50.55a(g), including ASME BPVC Section XI mandatory appendices.

The initial ISI Program incorporates the latest edition and addenda of the ASME BPVC approved in 10 CFR 50.55a(b) prior to initial fuel load as specified in 10 CFR 50.55a, subject to the conditions listed in 10 CFR 50.55a(b). Inservice examination of components and system pressure tests conducted during successive 120-month inspection intervals must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(b), subject to the conditions listed in 10 CFR 50.55a(b).

The specific edition and addenda of the Code used to determine the requirements for the inspection and testing plan for the initial and subsequent inspection intervals is to be delineated in the inspection program. The Code includes requirements for system pressure tests and functional tests for active components. The requirements for system pressure tests are defined in ASME BPVC, Section XI, Articles IWA-5000 and IWB-5000. These tests verify the pressure boundary integrity in conjunction with ISI. Section 6.6 discusses Class 2 and 3 component examinations.

5.2.4.1 Inservice Inspection and Testing Program

This section describes the process for assessing inspection and testing of the ASME BPVC Class 1components except for SG tubes. Section 5.4.1 describes the process for ISI requirements for the SG tubes.

The RCPB components are designed and provided with access to permit periodic inspection and testing of important areas and features to assess their structural and leak-tight integrity pursuant GDC 32. The design allows inspection, testing, and maintenance of the RSV, PZR heaters, SG primary and secondary sides, instruments, electrical connections, and other components located inside of the RCPB of the NPMs. Equipment that may require inspection or repair is placed in an accessible position to minimize time and radiation exposure during refueling and maintenance outages. Plant technicians access components without being placed at risk for excessive dose or situations where excessive plates, shields, covers, or piping must be moved or removed in order to access components.

The inspection requirements and conditions of 10 CFR 50.55a, as detailed in Section XI of the ASME BPVC, are met for Class 1 pressure-containing components and their supports. The RCPB components subject to inspection as Class 1 components are classified as Quality Group A as described in Section 3.2.2.1 and comply with the ASME BPVC as described in Section 5.2.1. Figure 6.6-1 shows the ASME BPVC Section III, Class 1 boundary for the RCS piping and SG system. Additionally, the ECCS valve actuators and actuator pressure sensing lines form a portion of the ASME BPVC Section III Class 1 boundary and are subject to ASME Section XI testing.

The inspection and testing program addresses the unique inspection and testing requirements for each NPM to ensure plant safety is maintained for the operating life.

The NPM inspection, testing, and maintenance strategy is: (1) design the NPM components to anticipate required inspections and (2) develop an ISI program to identify aspects such as interval and inspection frequencies, selection of components and welds for inspection, and expansion criteria.

Development of the NuScale inspection program consists of the following:

- identification of the appropriate ISI or testing requirements for the NuScale design (code version, overall inspections and tests required)
- identification of the structures, systems, and components (SSC), the subset inspections or test elements associated with SSC and those SSC which are subject to inspection and testing
- identification of appropriate ISI and testing requirements for each structure, system, and component
- assessment of each inspection and test element
- development of a comprehensive ISI and testing plan

The ISI schedule and requirements for Class 1 systems and components are in accordance with ASME BPVC, Section XI.

The following tables provide the applicable ISI examination categories and methods:

- Table 5.2-6 - Reactor Pressure Vessel Inspection Elements
- Table 5.2-7 - Reactor Vessel Internals Inspection Elements
- Table 5.2-8 - ASME Class 1 Piping Inspection Elements
- Table 5.2-9 - ASME Class 1 Support Inspection Elements

Prior to NPM startup following each refueling outage, a system leakage test is performed followed by a VT-2 examination for the RPV Class 1 pressure retaining boundary in accordance with the requirements specified in ASME BPVC, Section XI, Table IWB-2500-1 (B-P) and Articles IWA-5000 and IWB-5000. In the NuScale design, leakage is continuously monitored in the CNV or from the RPV to the CNV. This constitutes a VT-2 exam according to Section XI IWA-5241 (c). During normal operation, the CNV is in a vacuum, so leakage is from the pool to the inside of the CNV. The CNV leak detection system is able to detect leakage from both the RPV and CNV during normal operation.

The body-to-bonnet seals on the ECCS trip/reset actuator valve form the reactor coolant pressure boundary and require testing to RCS operating pressure prior to going into operation. Since this valve is located in the reactor pool during start-up there is no means to perform the required Section XI, Table IWB-2500-1 (B-P) VT-2 examination during the system pressure test. To confirm the seal integrity prior to start-up a seal verification test will be performed. The seal verification test will use the test port to pressurize the space between the inner and outer O-ring to RCS design pressure using a gas while the NPM is located in the dry dock. The seal test will be performed to the requirements of Section XI, Table IWB-2500-1 (B-P).

A surface and a volumetric examination is performed for ASME Class 1 pipe welds greater than or equal to four nominal pipe size (NPS). Only a surface examination is performed for pipe welds associated with ASME Class 1 piping less than four NPS, Table IWB-2500-1 Category B-J.

The ASME Class 1 boundary valves (i.e., CIVs) are located outside of the NPM. The reduced inspection requirements for the small primary system pipe welds associated with less than four NPS piping are not applied to the welds between the containment and the CIVs because a break at one of these weld locations would result in a RCPB leak outside the containment. Therefore, ASME Class 1 welds between the containment and the CIVs are inspected with a volumetric and surface examination each interval in accordance with the requirements of ASME BPVC, Section XI, Subarticle IWB-2500.

Flanges on the RPV have dual O-rings with a leak port tube between the O-rings to allow for leakage testing. Leakage testing is performed following installation of the O-rings each time they are removed to ensure a good seal.

The RPV and containment main flange bolts are inspected in accordance with the requirements specified in ASME BPVC, Section XI, Table IWB-2500-1 (B-G-1).

Pressure retaining bolting that two inches or less in diameter is inspected in accordance with the requirements specified in ASME BPVC, Section XI, Table IWB-2500-1 (B-G-2). These bolting assemblies require a VT-1 visual examination each interval if removed.

NuScale reactor vessel internals inspection requirements are developed consistent with the approach in the Materials Reliability Program (MRP) 227 (Reference 5.2-9) to augment the inspection requirements of ASME BPVC, Section XI. No exceptions are identified in determining internal inspection criteria using the MRP approach. Table 5.2-7 includes the ISI examination categories and methods for the reactor vessel internals. Included in the list are core support components, internal structures, and steam generator supports.

Based on the high pressure and the safety function of the containment, enhanced inspection requirements are provided for the containment in excess of the Class MC requirements of ASME BPVC, Section XI, Subsection IWE. The containment is inspected to selected Class 1 requirements of ASME BPVC, Section XI, Subsection IWB as specified in Table 6.2-8. All ASME BPVC, Section XI, Subsection IWE required inspections are met.

5.2.4.2 Preservice Inspection and Testing Program

Preservice examinations required by the design specification and preservice documentation are in accordance with ASME BPVC, Section III, Paragraph NB-5281. Volumetric and surface examinations are performed as specified in ASME BPVC, Section III, Paragraph NB-5282. Components described in ASME BPVC, Section III, Paragraph NB-5283 are exempt from preservice examination.

Surfaces of the RPV are designed to be suitable for examinations and conform to the applicable requirements of ASME BPVC Sections III and XI. For welds requiring an ultrasonic preservice examination, the surface finish meets the requirements of ASME BPVC Section III, Subsubparagraph NB-4424.2(a) except that the surface finish for Class 1 piping welds are 125 in Ra or better and the surface flatness is less than 0.03125 inches for a minimum distance of two times the thickness of the part from the weld centerline.

The containment is a Class MC containment in accordance with ASME BPVC, Section III, Subsection NE; however, it is designed, fabricated, and stamped as a Class 1 pressure vessel in accordance with BPVC, Section III, Subsection NB, with overpressure protection in accordance with ASME BPVC, Section III, Article NE-7000. Refer to Sections 3.8.2 and 6.2 for additional description of the containment compliance with the ASME BPVC, including preservice inspection and ISI and testing.

Preservice examinations for ASME Code Class 1 pressure boundary and attachment welds conform with ASME BPVC, Section III, Paragraph NB-5280 and ASME BPVC, Section XI, Subarticle IWB-2200. Examination methods are in accordance with ASME BPVC Section V except as modified by ASME BPVC, Section III, Paragraph NB-5111. These preservice examinations include 100 percent of the pressure boundary welds.

Preservice eddy current examinations for the SG tubing are in accordance with the applicable requirements of the EPRI Steam Generator Management Program guidelines (Reference 5.2-8) and ASME BPVC Section XI.

COL Item 5.2-6: A COL applicant that references the NuScale Power Plant design certification will develop site-specific preservice examination, inservice inspection, and inservice testing program plans in accordance with Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code and will establish implementation milestones. If applicable, a COL applicant that references the NuScale Power Plant design certification will identify the implementation milestone for the augmented inservice inspection program. The COL applicant will identify the applicable edition of the American Society of Mechanical Engineers Code utilized in the program plans consistent with the requirements of 10 CFR 50.55a.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection

The RCS of each NPM does not employ traditional light water reactor components with designed leakage rates, such as through pump seals or valve stem shafts.

For each NPM, distinguishing between RCS identified and unidentified leakage inside the containment is not practicable with the installed instrumentation. Leakage into containment may originate from sources other than from the RCPB (e.g., leakage from reactor component cooling water). Leakage is expected from the RCS to containment through mechanical boundaries such as the RRVs, RVVs, and RSVs. A partial vacuum condition is established in the CNV during NPM startup and maintained during reactor operation. As a result, reactor coolant leakage, whether from a known or unknown source, into containment quickly vaporizes and disperses within the containment atmosphere. Upon vaporization, there is no feasible means to monitor separately the flow rates of identified and unidentified leakage from inside the containment. Therefore, containment leakage is treated as unidentified until the source location is known and leakage quantified by other means. The RCS leakage rate into the containment is determined by performing an RCS inventory balance and comparing it to the total flow rate into the CES. The operational unidentified leakage limit is provided in plant technical specifications.

The RCPB leakage detection systems are sufficiently reliable, redundant, and sensitive to support the application of leak-before-break analyses addressed in Section 3.6.3.

5.2.5.1 Leakage Detection and Monitoring

The containment evacuation system (CES) maintains the containment below saturation pressure, which prevents water vapor from leaks or other sources from condensing into a liquid state and collecting at the bottom of the CNV; as such, monitoring containment water level for RCS leakage is not a reasonable option. Two primary methods of leakage monitoring are provided to detect leakage into containment; a change in containment pressure and condensate collected from the CES. The RCS leakage detection instrumentation requirements are specified in plant technical specifications.

Leakage Monitoring - CES Collected Condensate

Water vapor and noncondensable gas are removed by the CES, and the water vapor is condensed. The condensed water collects into the CES sample vessel where it is monitored using pressure, temperature and radioactivity instrumentation. The radioactivity instrumentation aids in determining the source of containment leakage; higher radioactivity may indicate RCS leakage. The CES sample vessel also includes level instrumentation that is used to quantify and trend leak rates into the containment. Additionally, CES gaseous discharge radioactivity monitoring may detect a fuel leak or excessive RCS leakage.

The CES is a nonsafety-related system, and the CES components are NuScale Power Module-specific. The primary function of the CES is to decrease and maintain the internal containment pressure below the saturation pressure corresponding to the lowest surface temperature inside the CNV. As a result of maintaining the entrained water in a gaseous state, the CES vacuum pumps remove water vapor and noncondensable gas within the CNV.

The CES condensate monitoring system provides indication and alarm in the main control room to monitor and trend liquid leakage into the containment atmosphere. The CES condensate monitoring system can detect an RCS leak rate of less than 1 gpm within one hour and has a minimum detectable leak rate of less than 0.05 gpm. A CES alarm is provided to the main control room (MCR) based on reaching 75 percent of the maximum allowable pressure-temperature for a given reactor pool temperature to signal to the operator the approaching operability limit. Refer to Section 9.3.6 for a description of the design and functions of the CES and associated sampling system.

The condensate measurement method is used to get a true leakage rate. Vapor pulled from the containment and condensed after leaving the vacuum pump is represented by measurement of the collected condensate. A correction factor is applied to ensure conservatism in the indicated leak rate. The correction factor is based on the calculated carryover rate past the CES condenser. Condensation of vapor within the containment must be avoided in order for the CES to properly account for leakage into containment. This method requires containment pressure to be stabilized below containment saturation pressure to ensure that the rate at which the water vapor is being drawn from containment is equivalent to the rate at which water mass is leaking into containment.

Leakage Monitoring - Containment Pressure

The CES inlet pressure instrumenation, which monitors containment pressure, is also used as an indicator to detect leakage. The CES inlet pressure instrumentation is designed to Seismic Category I, and provides indication in the MCR. The minimum pressure accuracy of the CES inlet pressure instrumentation allows for accurate trending of leakage data and can detect an RCS leak rate of less than 1 gpm in one hour with a minimum detectable leak rate of less than 0.05 gpm. Leak rate is calculated by using the time for pressure to change, gas load in containment, and the net mass flow rate inside containment.

For detecting leaks using the containment pressure instrumentation, the leak must be significant enough to change the pressure inside of the CNV by the minimum accuracy of the instrument. Therefore, systems operating at a higher temperature and pressure are easier to detect. The containment pressure monitoring instrumentation is capable of detecting a minimum leak rate from the RCS of 0.007 gpm and containment pressure will increase 0.1 psi in less than one minute with a 1 gpm leak from the RCS.

Once the operators observe a pressure change in containment, a leak rate procedure is initiated to determine the source of the containment leak and quantify the total leak rate. The change in containment pressure combined with other plant indications can help determine the leak source.

Maintaining acceptable containment leakage detection performance using the containment pressure monitoring and CES condensate monitoring systems is dependent on maintaining containment pressure below the vapor pressure for the lowest internal containment wall temperature. For conservatism, the minimum containment wall temperature is assumed to be equal to the reactor pool bulk temperature. Figure 5.2-3 provides a containment pressure saturation curve as a function of reactor pool bulk temperature with an adjustment to account for containment pressure instrumentation uncertainty. When containment pressure is in the Not Acceptable region of Figure 5.2-3, condensation may exist inside the containment thus impacting the accuracy of the containment pressure monitoring and CES condensate monitoring systems.

The piping between the containment and the CES up to the first seismic restraint outside of the CNV and the CES inlet pressure instrumentation is designed to Seismic Category I and ensures that these components maintain capability to perform their safety function during and after a safe shutdown earthquake. The remaining CES equipment is designed to Seismic Category II or III. Because the CES equipment is required to maintain containment vacuum, loss of this equipment or a containment isolation during a seismic event will result in a loss of containment vacuum and a subsequent NPM trip.

During a seismic event with the CES equipment still available to maintain containment vacuum, the CES sampling system continues to collect and measure condensate from the containment, including leakage from the RCPB, until failure of the non-seismic portion of the CES, at which point containment pressure would increase and isolate the containment.

The CES inlet pressure instrumentation is designed to Seismic Category I and ensures that these components maintain the capability to perform their safety leak monitoring function during and after a safe shutdown earthquake. Therefore, the CES inlet pressure instrumentation is also capable of detecting changes in the containment atmospheric conditions, including leakage from the RCPB, during a seismic event that does not result in an NPM shutdown.

Radioactivity Monitoring & Chemistry Analysis

The CES has the ability to monitor both gaseous and liquid effluent removed from containment for radioactivity using remote radioactivity instrumentation (See Figure 9.3.6-1).

Gaseous discharge of the CES is directed to the process sampling system sample panel for continuous analysis or collection of grab samples if needed. A grab sample location is also provided on the CES sample vessel, allowing for samples to be collected and analyzed in the laboratory.

Using the different radioisotope characteristics of systems (including the use of tracer gases), the source of a leak could be determined. FSAR Section 11.5 provides discussion on the use of radioisotopes to aid in determining the source of leakage.

RCS Inventory Mass Balance

The licensee will regularly perform a reactor coolant system inventory balance to determine RCS leakage quantity as part of technical specification surveillance requirement 3.4.5.1.

Using the inventory mass balance will augment radiation instrumentation, chemistry analysis, and CES leak detection methods to determine the source of a leak inside containment. To the extent practical, the use of these diverse methods provides identification of the location of the source of reactor coolant leakage.

5.2.5.2 Leak-Before-Break

Leakage into the containment from feedwater or steam piping is not considered plausible because there are no mechanical fittings or valves within the containment associated with these lines. However, calculations were performed as an input to the leak-before-break evaluations to determine the adequacy of the leakage monitoring instrumentation. To ensure adequate margin exists for leak detection, the leak-before-break evaluations considered a through wall flaw leak rate of 10 times larger than the minimum RCS leak detection capability with an additional safety factor of two between the critical break flaw size and leakage flaw size. For further information regarding leak-before-break, refer to Section 3.6.3.

5.2.5.3 Reactor Pressure Vessel Flange Leak-Off Monitoring

Bolted flanges and covers in the RCS are sealed by double concentric O-rings. These flanges and covers include a leak-off port located between the two concentric O-ring grooves providing the capability to pressurize the space between the O-rings thereby confirming that the O-ring seals are leak tight prior to operation. The maximum diameter of the leak-off connection is restricted by an orifice to a size such that a break is less than the normal makeup capacity of CVCS. Additional RPV flange leak-off monitoring is not provided.

5.2.5.4 Reactor Safety Valve and Emergency Core Cooling System Valve Leakage Monitoring

Leakage from the RSVs, ECCS valves, and actuators is exhausted directly to the containment atmosphere and is included in the total unidentified leakage into the containment. Specific leakage monitoring of the RSVs, ECCS valves, and pilot actuators is not provided.

5.2.5.5 Chemical and Volume Control System Intersystem Leakage Monitoring

Leakage from the CVCS outside the RCPB is classified as identified leakage. The design provides closed piping to collect potential CVCS leakage. The CVCS leakage from pumps, valves or flanges that contain potentially radioactive liquid effluents from system vents, drains and relief valves is collected and drained to the reactor building equipment drain sump and pumped to the low conductivity waste collection tanks. The liquid radioactive waste system provides the capability to monitor the level of the low conductivity waste collection tanks. An annunciation system alarms when a pre-set high leakage level in the tank is reached.

The CVCS is connected to the RCPB via normally open CIVs. Intersystem leakage from the CVCS to connecting systems is considered for:

- boron addition system and demineralized water system.
- reactor component cooling water system (RCCWS).

- process sampling system.
- module heatup system heat exchangers.
- letdown to the liquid radioactive waste system.

Intersystem leakage is identified by:

- increasing level, temperature, flow or pressure.
- relief valve actuation.
- increasing radioactivity.

Refer to Sections 9.3.3, 9.3.4, and 11.5 for further discussion related to the CVCS intersystem leakage detection and monitoring capabilities.

5.2.5.6 Reactor Component Cooling Water System Leakage Monitoring

Leakage detection for the RCCWS is provided by monitoring expansion tank level and an alarm is provided in the control room. In the event radioactivity is introduced into the RCCWS piping, radiation elements and transmitters located downstream of non-regenerative heat exchanger, the process sampling system cooler lines, and the CES condenser for each NPM detect the radiation and alarm in the control room. For additional information on RCCW, see Section 9.2.2.

5.2.5.7 Primary to Secondary Leakage Monitoring

Radiation monitoring of the gaseous effluent from the condenser air removal system is provided to detect primary to secondary leakage. Radiation monitoring is also provided on the main steam lines condenser air removal system, and turbine sealing steam system. The capability to attain grab samples of steam and feedwater to analyze for indications of primary to secondary leakage is also provided. Additional detail of gaseous and liquid effluent radioactivity monitoring is provided in Section 11.5.

COL Item 5.2-7: A COL applicant that references the NuScale Power Plant design certification will establish plant-specific procedures that specify operator actions for identifying, monitoring, and trending reactor coolant system leakage in response to prolonged low leakage conditions that exist above normal leakage rates and below the technical specification limits. The objective of the methods of detecting and trending the reactor coolant pressure boundary leak will be to provide the operator sufficient time to take actions before the plant technical specification limits are reached.

5.2.6 References

5.2-1 NuScale Power, LLC, "Non-Loss-of-Coolant Transient Analysis Methodology," TR-0516-49416, Rev. 0.

5.2-2 NuScale Power, LLC, "Loss-of-Coolant Evaluation Model," TR-0516-49422, Rev. 0.

5.2-3 Electric Power Research Institute, "Pressurized Water Reactor Primary Water Chemistry Guidelines," EPRI #3002000505, Rev. 7, Palo Alto, CA, 2014.

5.2-4 Not Used.

5.2-5 American Society of Mechanical Engineers, "Quality Assurance Requirements for Nuclear Facility Applications," ASME NQA-1-2008/1a-2009 Addenda, New York, NY.

5.2-6 Electric Power Research Institute, "Materials Reliability Program: Resistance to Primary Water Stress Corrosion Cracking of Alloys 690, 52, and 152 in Pressurized Water Reactors (MRP-111)," EPRI #1009801, Palo Alto, CA, 2004.

5.2-7 Electric Power Research Institute, "Materials Reliability Program: Resistance to Primary Water Stress Corrosion Cracking of Alloy 690 in Pressurized Water Reactors (MRP-258)," EPRI #1019086, Palo Alto, CA, 2009.

5.2-8 Electric Power Research Institute, "Steam Generator Management Program: Pressurized Water Reactor Steam Generator Examination Guidelines," EPRI #1013706, Rev. 7, Palo Alto, CA, 2007.

5.2-9 Electric Power Research Institute, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),” EPRI #1022863, Palo Alto, CA, 2011.

Table 5.2-1: American Society of Mechanical Engineers Code Cases

Code Case Number	Title	Revision
N-759-2	Alternative Rules for Determining Allowable External Pressure and Compressive Stresses for Cylinders, Cones, Spheres, and Formed Heads, Class 1, 2, and 3, Section III, Division 1	January 2008
N-62-7	Internal and External Valve Items, Section III, Division 1, Classes 1, 2, and 3	February 2003
N-60-5	Material for Core Support Structures, Section III, Division 1	February 1994

Table 5.2-2: Reactor Safety Valves - Design Parameters

	Number	2
Valve size	Inlet	3 inch
	Outlet	4 inch
Design pressure	Internal	2100 psia
	External	1000 psia
Design temperature		650°F
	Minimum design capacity @ 3% overpressure	63,360 lbm/hr saturated steam
Nominal RSV setpoint	Nominal setpoint First valve Second valve	 2075 psia ±1% 2100 psia ±1%
Blowdown from set pressure		10% ±2%

Table 5.2-3: Not Used

Table 5.2-4: Reactor Coolant Pressure Boundary Component and Support Materials Including Reactor Vessel, Attachments, and Appurtenances

Component	Specification	Alloy Designation (Grade, Class, or Type)[1]
Reactor Vessel		
Lower RPV section flange shell RPV bottom head	SA-508	Grade 3, Class 1
RPV top head PZR Shell Integral steam plenum Upper RPV flanged transition shell Steam plenum access ports Upper RPV SG shell Lower RPV SG shell Feed plenum access ports	SA-508	Grade 3, Class 2
RPV support gussets RPV support plates	SA-533	Type B, Class 2
Core barrel guides	SA-479 or SA-240	Type 304 with 0.03% max carbon
Core support blocks	SA-240	Type 304L
Pressure instrument tap swagelok reducers Threaded inserts for: RSV flanges RPV instrument seal assemblies PZR heater access ports Steam plenum access ports Feed plenum access ports	SA-479	Type 304/304L
RPV instrument seal assemblies	SA-240	Type 304/304L
RPV instrument seal assemblies set screws	SA-193	B8, Class 1
RPV instrument seal assemblies swagelok male connectors	SA-479	Type 316/316L
RPV flange leak detection tube	SA-312	Type 316L; Seamless
Threaded fasteners, nuts, and washers for: Main RPV flange RSV flanges RPV instrument seal assemblies PZR heater access ports Steam plenum access ports Feed plenum access ports	SB-637	Alloy 718 (UNS N07718)[3]
PZR pressure taps Thermowell nozzles	SB-166	Alloy 690 (UNS N06690)
Safe ends for: • CVCS charging and letdown nozzles • CRDM nozzles • High point degasification nozzle • Pressurizer Spray nozzle	SB-166 or SB-167[5]	Alloy 690 (UNS N06690)
PZR heater closure flange	SB-168	Alloy 690 (UNS N06690)
Ultrasonic testing sensor nozzles	SA-182	Grade F304/F304L

Table 5.2-4: Reactor Coolant Pressure Boundary Component and Support Materials Including Reactor Vessel, Attachments, and Appurtenances (Continued)

Component	Specification	Alloy Designation (Grade, Class, or Type)[1]
Low alloy steel weld filler material[4]	SFA 5.5 SFA 5.23 SFA-5.28 SFA-5.29	Weld filler metal classifications compatible with low alloy steel base metal
Stainless steel weld filler material[2] (includes filler material for cladding)	SFA 5.4 SFA 5.9 SFA-5.22	E308, E308L, E309, E309L, E316, E316L ER308, ER308L, ER309, ER309L ER316, ER316L, EQ308L, EQ309L E308, E308L, E309, E309L, E316, E316L
Nickel-based alloy weld filler material	SFA-5.11 SFA-5.14	ENiCrFe-7 ERNiCrFe-7, ERNiCrFe-7A, EQNiCrFe-7, EQNiCrFe-7A
Steam Generators		
SG tubes	See Section 5.4.1.5	
SG tube supports	SA-240	Type 304/304L
Upper and Lower SG supports	SA-240	Type 304/304L
Integral steam plenum cap	SB-564	Alloy 690 (UNS N06690)
Nickel-based alloy weld filler material	SFA-5.11 SFA-5.14	ENiCrFe-7 ERNiCrFe-7, ERNiCrFe-7A, EQNiCrFe-7, EQNiCrFe-7A
Piping	See Table 5.4-3	
Piping supports		
Piping reducers and elbows		
RVVs and RRVs		
Refer to Table 6.1-3		
RCS Piping		
RCS injection line, CNV to RPV RCS discharge line, RPV to CNV RPV high point degasification line, RPV to CNV PZR spray supply line, CNV to RPV	SA-312	Grade TP304/304L
Stainless steel weld filler materials[2]	SFA 5.4 SFA 5.9	E308, E308L, E316, E316L ER308, ER308L, ER316, ER316L
RCS piping reducers and elbows	SA-479	Type 304/304L
Tee connection to ECCS reset valves	SA-182	Grade F304/F304L
Reactor Safety Valves, RCS injection and Discharge line isolation valves, Pressurizer spray line isolation valves, and RPV high point degasification isolation valves		
Refer to Table 6.1-3		
RCS Piping Supports		
RCS Piping Supports (short, long, tube)	SA-479	Type 304/304L
Pressurizer Support Anchor and Support Plate 180 Degree Piping Supports 90 Degree Piping Supports	SA-240	Type 304/304L

Table 5.2-4: Reactor Coolant Pressure Boundary Component and Support Materials Including Reactor Vessel, Attachments, and Appurtenances (Continued)

Component	Specification	Alloy Designation (Grade, Class, or Type)[1]
CRDM Pressure Retaining Components		
Latch housing Rod travel housing Rod travel housing Plug	SA-965	Grade F304LN

Note:

(1) When the material is designated as Type or Grade 304/304L, this refers to dual-certified stainless steel material.

(2) Carbon content of unstabilized Type 3XX weld filler materials is restricted to 0.03% maximum.

(3) Solution treatment temperature range prior to precipitation hardening treatment is restricted to 1800 °F to 1850 °F.

(4) Low-alloy steel weld metals for the RPV match the low-alloy steel base metals in terms of chemical composition. Low-alloy steel weld metals for the RPV meet the minimum mechanical property requirements of the selected low-alloy steel base metal.

(5) Safe ends larger than 5 inches using SB-167 UNS N06690 material meet ASME BPVC, 2015 edition, Section II.

Table 5.2-5: Reactor Coolant Water Chemistry Controls

Parameter (units)	Normal Operating Range	RG 1.44 Limit
Chloride (ppm)	≤ 0.05	0.15
Fluoride (ppm)	≤ 0.05	0.15
Dissolved oxygen (ppm)	≤ 0.005	0.10
Sulfate (ppm)	≤ 0.05	-
Hydrogen (cc/kg)	25 - 50	-
Boron (ppm)	0 - 2000	-

Table 5.2-6: Reactor Pressure Vessel Inspection Elements

Description	Examination Category	Examination Method	Notes
RPV Shell and Head Welds			
Lower RPV flange shell to RPV bottom head Upper RPV flanged transition shell to lower SG shell Lower SG shell to upper SG shell Upper SG shell to integral steam plenum Integral steam plenum to PZR shell PZR shell to RPV top head Steam plenum cap to integral steam plenum	B-A	Volumetric	
RPV Internal Welds			
Core support block to RPV bottom head Core support block to latch Core barrel guide to lower RPV flange shell Upper SG support to lower RPV integral steam plenum Lower SG support to upper RPV	B-N-2	VT-3	
Instrumentation and Controls Sleeve Welds	None	None	These welds are part of the cladding.
Flow diverter to RPV lower head RPV interior surfaces and attachment welds	B-N-1	VT-3	B-N-1 is for the space above and below the core made accessible by removal of components during a normal refueling outage
RPV External Welds			
RPV support plate to RPV support gussets RPV support plate to upper RPV SG shell 1-4	F-A	VT-3	
RPV support plate to upper RPV SG shell RPV support gussets to upper RPV SG shell RPV lateral support lug	B-K	Surface or Volumetric	
RPV Nozzle to Shell and Head Welds			
Reactor recirc valve flange Feedwater nozzles RCS discharge	B-D	Volumetric	Inside corner. All welds examination requirement IWB-2500-7(d).
Main steam nozzles	B-D	Volumetric	Examination requirement IWB-2500-7(d)
RCS injection PZR spray supply lines	B-D	N/A	No inside corner

Table 5.2-6: Reactor Pressure Vessel Inspection Elements (Continued)

Description	Examination Category	Examination Method	Notes
Reactor vent valve flange Reactor safety valves RPV high point degasification CRDM nozzles	B-D	None	Inside corner region examinations are not required for pressurizer nozzles by ASME BPVC, Section XI. Therefore, these nozzles are exempted from inspection given the nozzles have the same functionality and consequences as traditional pressurizer nozzles region of the vessel.
PZR heater access ports I&C - Channels	B-D	Not required	See ASME BPVC, Section XI, Table IWB-2500-1 (B-D) Note 1.
Feedwater plenum access ports Main steam plenum access ports	B-D	Volumetric	Examination requirement IWB-2500-7(b) Examination requirement IWB-2500-7(c) All welds, no inside corner
PZR pressure taps T-Hot thermowells PZR liquid temp thermowells PZR T-Hot thermowells Ultrasonic testing sensor nozzles	B-D	Volumetric	Examination requirement IWB-2500-7(a) Examination requirement IWB-2500-7(a) Examination requirement IWB-2500-7(a) Examination requirement IWB-2500-7(a) Examination requirement IWB-2500-7(b) All welds, no inside corner, shell side exam only
Nozzle-to-Safe End Dissimilar Metal Welds			
Feedwater nozzle safe ends Main steam nozzle safe ends	B-F	Surface and Volumetric	
RCS injection safe end (inner and outer) RCS discharge safe end PZR spray supply safe end (outer) RPV high point degasification safe end	B-F	Surface	
PZR spray supply safe end (inner)	None	None	Open ended pipe
CRDM nozzle safe ends	B-O	Volumetric or Surface	
Threaded Fastener Threaded Inserts and Threaded Insert Welds			
RSV flanges I&C access ports PZR heater access ports Steam plenum access ports Feed plenum access ports RVV flanges RRV flanges	None	VT-1	No inspection requirement. Augmented to VT-1 when bolts are removed.

Table 5.2-6: Reactor Pressure Vessel Inspection Elements (Continued)

Description	Examination Category	Examination Method	Notes
Bolting			
RPV main flange bolts	B-G-1	See note	Per Note 1 of B-G-1, surface examination is permitted when bolts are removed.
RVV and RRV flange threaded fasteners	B-G-2, augmented	Volumetric	Augmented inspection to follow the guidance of B-G-1. No sampling permitted. All threaded fasteners are subject to volumetric examination during the inspection interval.
RPV bolting two inches or less in diameter	B-G-2	VT-1	Examined if removed.
Assembled RPV			
RPV- assembled after refueling outage	B-P	VT-2	Per Section XI IWA-5241(c), leakage is continuously monitored in the CNV and constitutes a VT-2 examination.

Table 5.2-7: Reactor Vessel Internals Inspection Elements

Description	Location	Examination Category	Examination Method	Notes
Core Support Components				
Reflector Block - Bottom	Core Support Assembly	B-N-3	VT-3	
Reflector Block Intermediate	Core Support Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1. Exam will be of the interior surface, checking for a gap developing between reflector blocks.
Reflector Block Top	Core Support Assembly	B-N-3	VT-3	
Reflector Block Alignment Pins	Core Support Assembly	B-N-3	VT-1	Inspection only required when reflector blocks are removed for another reason
Core Barrel	Core Support Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1 of accessible surfaces
Lower core Plate	Core Support Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1 of accessible surfaces
Upper Core Plate	Lower Riser Assembly	B-N-3	VT-3	
Lower Core Plate Alignment Pins	Core Support Assembly	B-N-3	VT-3	
Socket Head Cap Screws	Core Support Assembly	B-N-3	VT-3	Mating interface between upper core support block and lower riser
Alignment Dowels	Core Support Assembly	B-N-3	VT-3	Mating interface between upper core support block and lower riser
Upper Support Block	Core Support Assembly	B-N-2	VT-1	
Core Barrel to Lower Core Plate	Core Support Assembly	B-N-2	VT-1	
Fuel Pins	Lower Riser Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1
Fuel Pins Caps	Lower Riser Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1
Fuel Pin Capture Weld	Lower Riser Assembly	B-N-2	VT-1	
Shared Fuel Pins and Nuts	Core Support Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1
Lower Riser to Upper Core Plate	Lower Riser Assembly	B-N-3	VT-3	
ICIGT Bottom Flag ICIGT 1 to Upper Core Plate	Lower Riser Assembly	B-N-3	VT-1	Required VT-3 augmented to VT-1

Table 5.2-7: Reactor Vessel Internals Inspection Elements (Continued)

Description	Location	Examination Category	Examination Method	Notes
Core Support Block Assembly	Core Support Assembly	B-N-3	VT-3	Includes cap screws and dowels
Internal Structures				
ICI Guide Tubes	Lower Riser Assembly	N/A	VT-3	
ICI Guide Tubes (Upper)	Upper Riser Assembly	N/A	VT-3	
ICI Guide Tubes Bottom Flag	Lower Riser Assembly	N/A	VT-1	Required VT-3 augmented to VT-1
CVCS Makeup Piping Assembly	Upper Riser Assembly	N/A	VT-3	
Upper CRDS Support	Upper Riser Assembly	N/A	VT-3	
Upper Hanger Assembly Fasteners	Upper Riser Assembly	N/A	VT-3	
Upper Hanger Ring & Reinforcements	Upper Riser Assembly	N/A	VT-3	
Lower Riser Section	Lower Riser Assembly	N/A	VT-3	
Lower Riser Trunnion	Lower Riser Assembly	N/A	VT-3	
Lower Riser Spacer	Lower Riser Assembly	N/A	VT-3	
Lower Riser Spacer to Lower Riser Section	Lower Riser Assembly	N/A	VT-3	
Lower Riser Transition to Lower Riser Spacer	Lower Riser Assembly	N/A	VT-3	
ICIGT Support to Lower Riser Transition	Lower Riser Assembly	N/A	VT-3	
ICIGT Support to ICIGT	Lower Riser Assembly	N/A	VT-3	
ICIGT Bottom Flag to ICIGT	Lower Riser Assembly	N/A	VT-3	
CRA Guide Tube Support Plate to Lower Riser Spacer	Lower Riser Assembly	N/A	VT-3	
CRA Guide Tube Assembly (including Guide Cards)	Lower Riser Assembly	N/A	VT-3	
Upper Riser Section Seam	Upper Riser Assembly	N/A	VT-3	
Riser Backing Strip A	Upper Riser Assembly	N/A	VT-3	
Riser Backing Strip B	Upper Riser Assembly	N/A	VT-3	
Upper CRDS Support	Upper Riser Assembly	N/A	VT-3	
Brace to Upper Riser Hanger Ring	Upper Riser Assembly	N/A	VT-3	
Brace to Upper Riser Section	Upper Riser Assembly	N/A	VT-3	

Table 5.2-7: Reactor Vessel Internals Inspection Elements (Continued)

Description	Location	Examination Category	Examination Method	Notes
Upper Riser to Bellows	Upper Riser Assembly	N/A	VT-3	
Bellows to Upper Riser Transition	Upper Riser Assembly	N/A	VT-3	
Pipe to Bellows	Upper Riser Assembly	N/A	VT-3	
Elbow to Flexible Pipe	Upper Riser Assembly	N/A	VT-3	
Flexible Pipe to Rigid Pipe	Upper Riser Assembly	N/A	VT-3	
Brace to Pipe	Upper Riser Assembly	N/A	VT-3	
Pipe to Cap	Upper Riser Assembly	N/A	VT-3	
ICI Centering Plate 1-12	Upper Riser Assembly	N/A	VT-3	
ICIGT Link to Upper Riser Hanger Ring	Upper Riser Assembly	N/A	VT-3	
Injection to RPV11	Upper Riser	N/A	VT-3	
ICIGT to Integrated Steam Plenum	PZR	N/A	VT-3	
Pressurizer Spray Nozzle	PZR Spray Nozzle to Safe End (RPV14-RPV15)	N/A	VT-3	
Surveillance Capsule	Core Support Assembly	N/A	VT-3	

Table 5.2-8: American Society of Mechanical Engineers Class 1 Piping Inspection Elements

Description	Examination Category	Examination Method	Notes
Dual valve, single body isolation valve to safe-end	B-J	Surface and Volumetric	Refer to Section 5.2.4.1 for discussion on welds between the containment and the dual valve, single body CIVs.
CRDM nozzles	B-J	Surface or Volumetric	
RCS discharge piping and RPV nozzle safe end to piping RCS injection piping and RPV nozzle safe end to piping PZR spray piping and RPV nozzle safe end to piping RPV high point degasification piping and RPV nozzle safe end to piping	B-J	Surface	
RRV and RVV trip-reset actuators to safe ends	B-J	Surface	
RRV and RVV trip-reset actuators piping and fitting welds	B-J	None	Exempted by ASME BPVC Section XI, Paragraph IWB-1220 due to small size of piping and fittings.

Table 5.2-9: American Society of Mechanical Engineers Class 1 Support Inspection Elements

Description	Examination Category	Examination Method	Notes
CVCS to PZR RPV ledge to RPV ledge gussets CRDM lower, diagonal, and horizontal legs and support gratings Containment to RPV bolting	F-A	VT-3	
RCS discharge piping to containment RCS injection piping to containment PZR spray supply piping to containment RPV ledge and gussets to containment RPV support lug shells CRDM support frame to containment head Main steam and feedwater piping to supports inside containment Containment flood and drain system supports to containment	B-N-1	VT-3	
RCCW to containment head CRDM lower legs to RPV head DHRS piping to containment NPM platform NPM top supports to containment DHRS heat exchanger supports to containment	B-K	Surface	

Table 5.2-10: LTOP Pressure Setpoint as Function of Cold Temperature

Cold Temperature (°F)	PZR Pressure (psia)
<193.0	380.0
193.0	380.0
240.0	615.5
277.0	850.0
318.0	850.0
>318.0	LTOP not enabled

Figure 5.2-1: Reactor Safety Valve Simplified Diagram

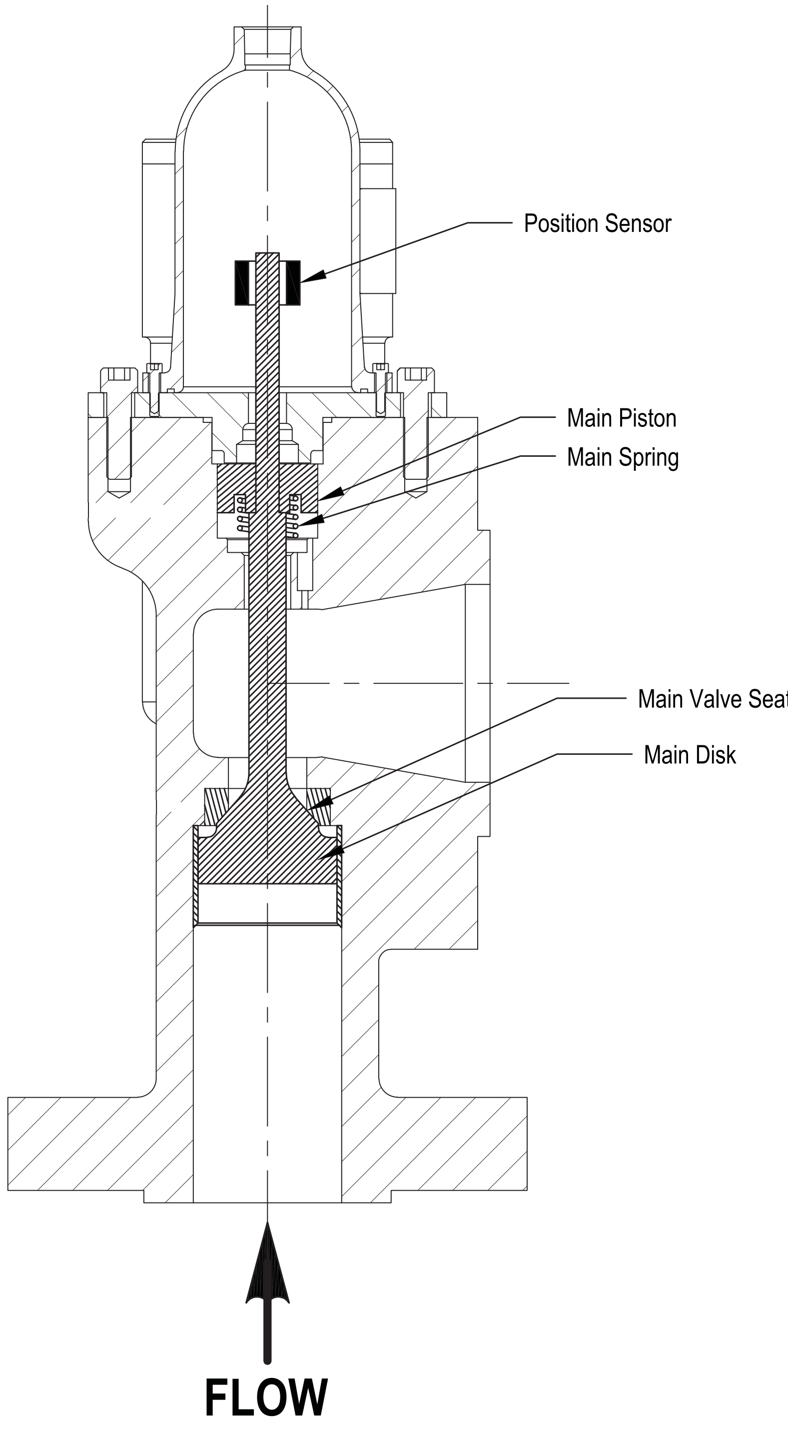


Figure 5.2-2: Reactor Safety Valve Pilot Valve Assembly Simplified Diagram

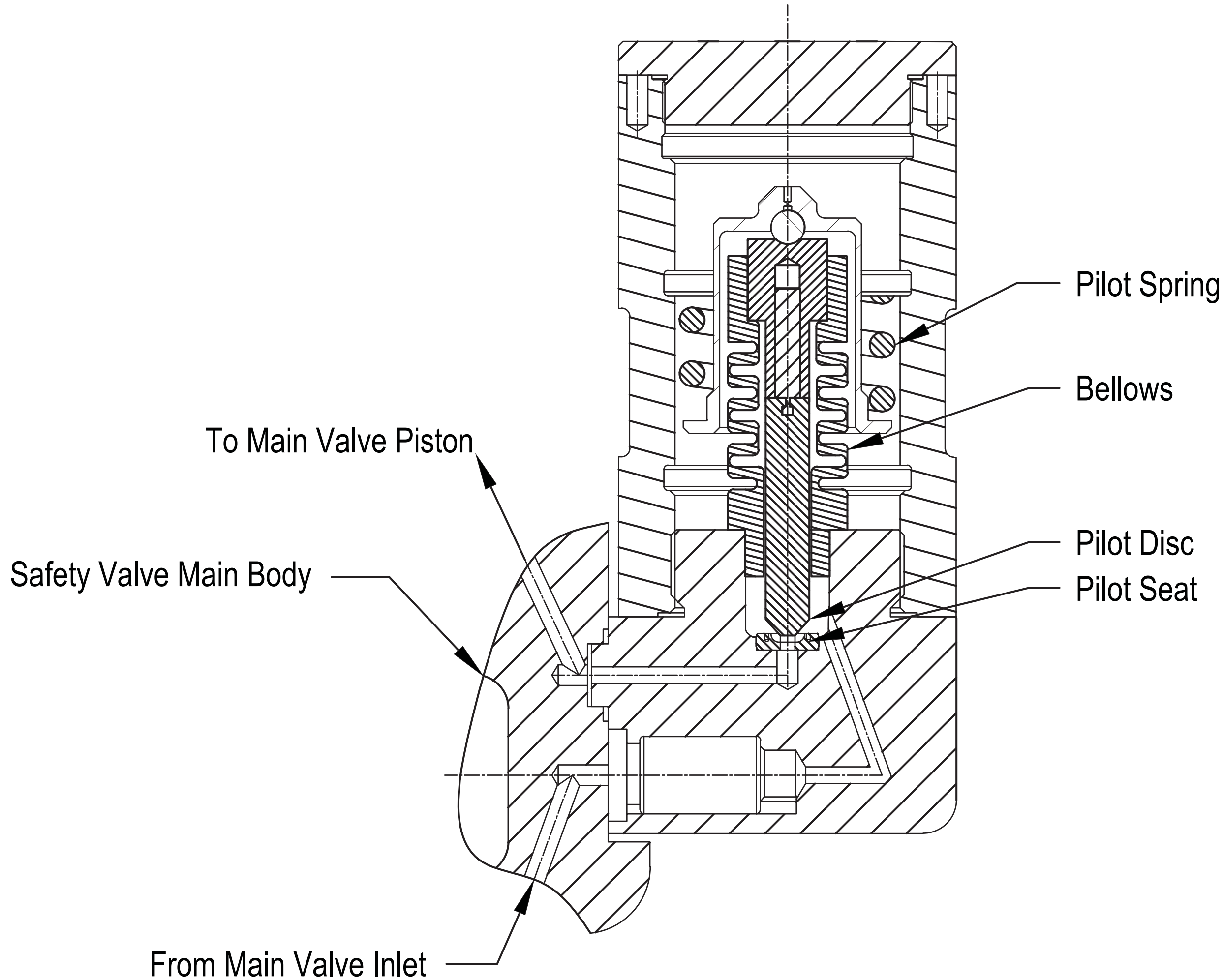


Figure 5.2-3: Containment Leakage Detection Acceptability

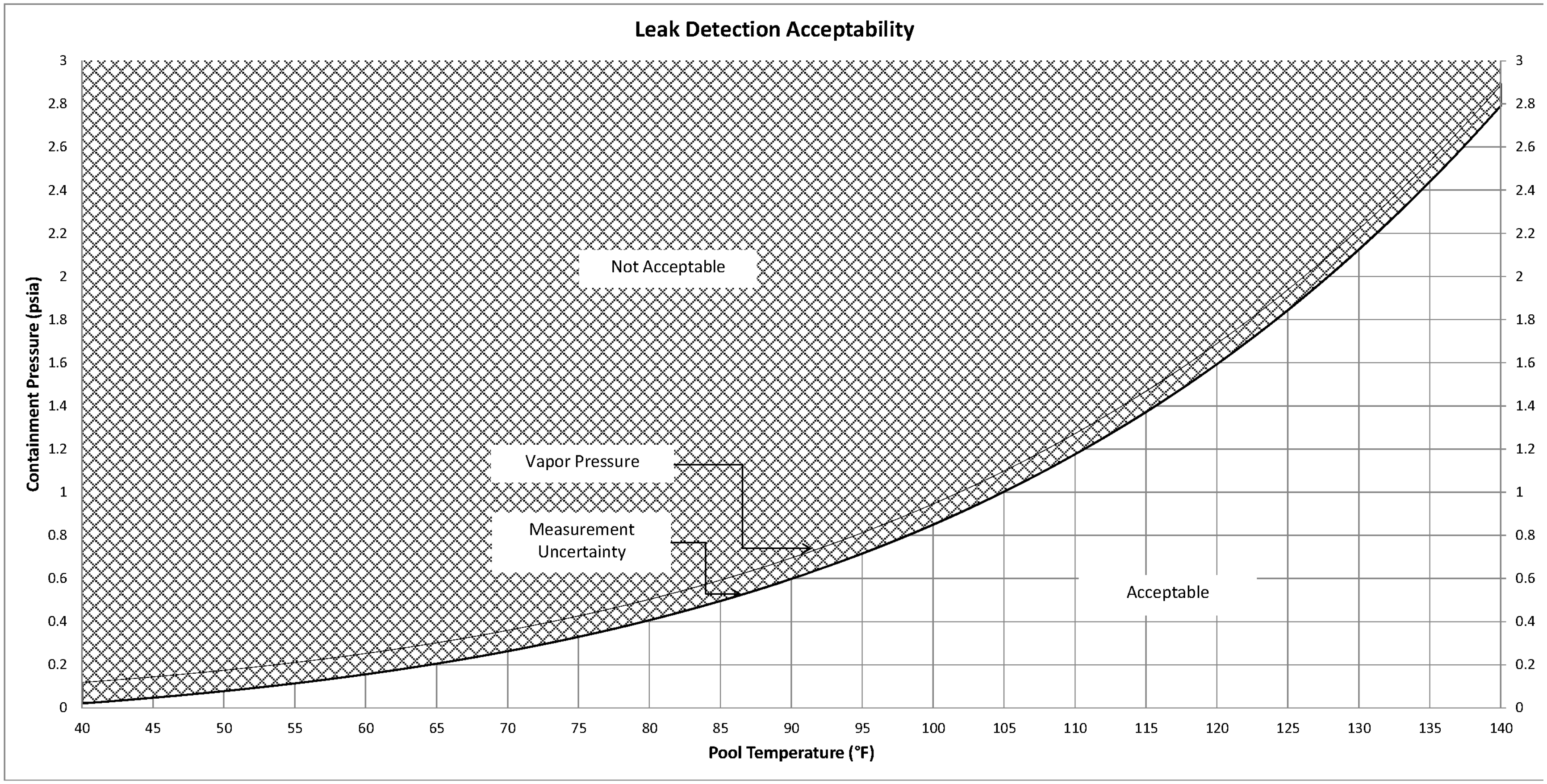
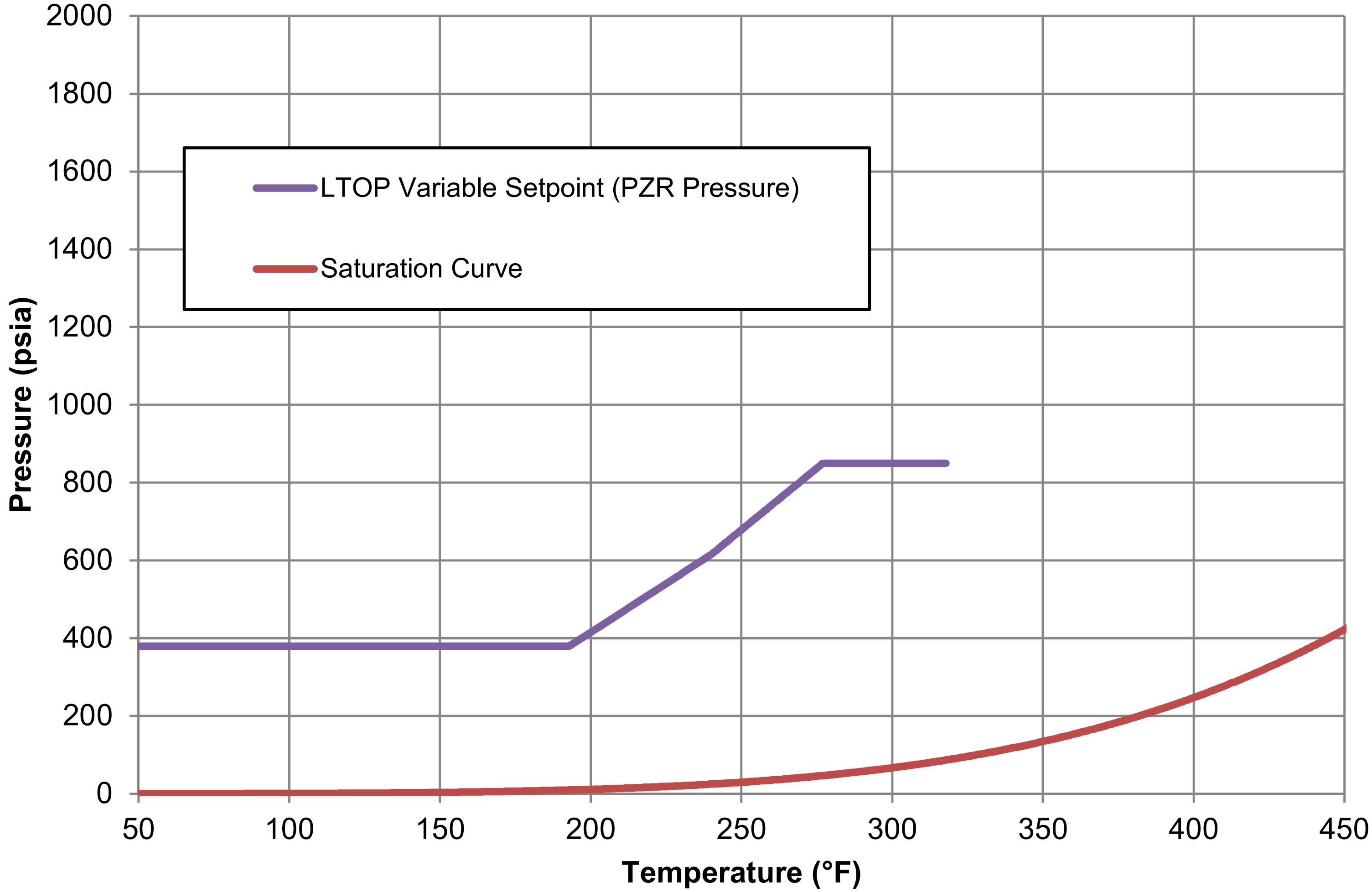


Figure 5.2-4: Variable LTOP Setpoint



5.3 Reactor Vessel

A NuScale Power Module (NPM) consists of a reactor core, two steam generators (SGs), and a pressurizer all contained within a single reactor pressure vessel (RPV), with a containment vessel (CNV) that surrounds the RPV. Each NPM includes the piping located between the RPV and the CNV.

The RPV is a pressure retaining vessel component of the reactor coolant system (RCS). The RCS is described in Section 5.1 and Section 5.2. The RPV metal vessel that forms part of the reactor coolant pressure boundary (RCPB) is a barrier to the release of fission products. The RPV contains the reactor core, reactor vessel internals, steam generators (SGs), pressurizer, and reactor coolant volume. The SGs are part of the RPV component. The RPV is supported laterally and vertically by the CNV. The RPV provides support and attachment locations for the control rod drive mechanisms (CRDMs), the CRDM seismic support structure, pressurizer heater bundles, in-core instrumentation, steam generator system piping, RCS piping, reactor safety valves (RSVs), reactor vent valves, and reactor recirculation valves. The RPV, which includes the SGs, is certified and stamped in accordance with Article NCA-8000 of ASME BPVC, Section III. The reactor vessel is shown in Figure 5.3-1 and design parameters are presented in Table 5.3-1.

5.3.1 Reactor Vessel Materials

5.3.1.1 Material Specifications

The materials and applicable specifications used in the RPV and appurtenances are shown in Table 5.2-4.

The RPV materials are selected and fabricated to maintain RCPB integrity for the plant design lifetime. Bolting materials, pressure retaining base materials, and weld filler materials are selected from the ASME Boiler and Pressure Vessel Code (BPVC), Section II and comply with Article NB-2000 of ASME BPVC, Section III (Reference 5.3-1). In addition, the fracture toughness properties of the ferritic RCPB pressure-retaining materials comply with the requirements of 10 CFR 50, Appendix G.

The RCPB materials comply with the relevant requirements of the following regulations:

- 10 CFR 50, Appendix A
  - GDC 1 and 30 - The RPV is designed, fabricated, and tested as ASME BPVC Class 1 to the highest quality standards in accordance with Quality Assurance Program described in Chapter 17.
  - GDC 4 - The RPV is designed and fabricated to be compatible with environmental conditions of the reactor coolant and containment atmosphere.
  - GDC 14 and 31 - The RPV is designed and fabricated with sufficient margin to assure the RCPB behaves in a non-brittle manner and to minimize the probability of rapidly propagating fracture and gross rupture of the RCPB.
- Appendix G to 10 CFR 50 - The RPV materials are tested and meet applicable fracture toughness acceptance criteria.

The chemical composition of the materials in the RPV beltline are shown in Table 5.3-2.

The chemical composition of unstabilized austenitic stainless steel materials that are welded or exposed to sensitizing temperatures in the range of 800 to 1500 degrees F subsequent to solution annealing, including weld filler materials, have a maximum carbon content of 0.03 wt%, consistent with Regulatory Guide (RG) 1.44, Revision 1.

The RPV is fabricated in accordance with the requirements of ASME BPVC Section III, NB-4000, except for the SG tube supports (shown in Figure 5.4-6), which are fabricated in accordance with ASME BPVC Section III, NG-4000, and the RPV supports and CRDM seismic support structure (shown in Figure 5.3-1), which are fabricated in accordance with ASME BPVC Section III, NF-4000.

COL Item 5.3-1: A COL applicant that references the NuScale Power Plant design certification will establish measures to control the onsite cleaning of the reactor pressure vessel during construction in accordance with Regulatory Guide 1.28.

5.3.1.2 Special Processes Used for Manufacture and Fabrication of Components

Forged low alloy steel is selected for the RPV assembly shells that surround the reactor core, pressurizer, and SGs. Forgings are used to form the various required geometries with minimum amount of welding.

Reactor pressure vessel cladding is addressed in Section 5.2.3.

Measures are taken to prevent sensitization of austenitic stainless steel materials during component fabrication. Heat treatment parameters comply with ASME BPVC, Section II. The austenitic stainless steel materials are either cooled by water quenching or cooled quickly enough through the sensitization temperature range to avoid carbide formation at the grain boundaries. When means other than water quenching are used, nonsensitization of the base material are verified by corrosion testing in accordance with Practice A or E of ASTM A262 (Reference 5.3-3).

Due to necessary component welding, it is unavoidable that the heat-affected zone within the austenitic stainless steel materials will be subjected to the sensitizing temperature range, 800 to 1500 degrees F, during fabrication. Welding practices and material composition are controlled to manage the sensitization while the material is in this temperature range and unstabilized Type 3XX austenitic stainless steels and corresponding austenitic stainless steel weld filler metals have a carbon content not exceeding 0.03 wt% to prevent undue sensitization. In addition, where unstabilized Type 3XX austenitic stainless steels are subjected to sensitizing temperatures for greater than 60 minutes during a post-weld heat treatment, non-sensitization of the materials are verified by testing in accordance with ASTM A262 Practice A or E, as required by RG 1.44.

5.3.1.3 Special Methods for Nondestructive Examination

The RPV pressure retaining and integrally attached materials examinations meet the requirements specified in ASME BPVC Section III. The examination methods are in accordance with ASME BPVC Section V, except as modified by Section III and any additional requirements listed below.

Non-destructive examination of the reactor coolant pressure boundary is addressed in Section 5.2.3.

Preservice examinations are in accordance with subsection NB-5280 of Section III and subsection IWB-2200 of Section XI for ASME Code Class 1 pressure boundary and attachment welds using the examination methods in Section V, except as modified by subsection NB-5111 of Section III. These preservice examinations include 100 percent of the pressure boundary welds.

For ASME Code Class 2 pressure boundary items, preservice examinations are in accordance with subsection IWC-2200 of Section XI.

5.3.1.4 Special Controls and Special Processes Used for Ferritic Steels and Austenitic Stainless Steels

Welding of ferritic steels used for components in the reactor vessel is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME Code, Section III, NB-4300 and Section XI (Reference 5.3-5). Further information is provided in Section 5.2.3.3.

Welding of austenitic stainless steel used for components in the reactor vessel is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME Code, Sections III and XI. Further information is provided in Section 5.2.3.4.

In addition, electroslag welding processes are not utilized for joining materials. Electroslag welding processes are allowed for cladding low alloy steel and comply with RG 1.34 requirements.

Tools for abrasive work are addressed in Section 4.5.2.4.

Use of cold worked austenitic stainless steel is addressed in Section 4.5.1.1.

5.3.1.5 Fracture Toughness

The fracture toughness properties of the RCPB pressure-retaining materials comply with the requirements of 10 CFR 50, Appendix G, "Fracture toughness requirements," and ASME BPVC, Section III, NB-2300.

The RPV is designed against non-ductile fracture in accordance with ASME BPVC, Section III, Appendix G, ASME BPVC, Section XI, Appendix G, and 10 CFR 50, Appendix G.

The pressure-temperature limits are developed in accordance with ASME BPVC, Section XI, Appendix G, 10 CFR 50, Appendix G, and RG 1.99, Revision 2.

Reactor vessel beltline materials are evaluated to ensure a minimum end-of-life Charpy V-notch upper shelf energy value of 50 ft-lb. The initial Charpy V-notch upper shelf energy value is 75 ft-lb minimum. Table 5.3-3 provides the 1/4-T adjusted reference temperature and upper shelf energy projections that were estimated using RG 1.99 for the end-of-life neutron fluence at the 1/4-T locations.

5.3.1.6 Material Surveillance

The Material Surveillance program monitors changes in the fracture toughness properties. Specimens are periodically removed and tested in order to monitor changes in fracture toughness in accordance with ASTM E185-82, as required by 10 CFR 50, Appendix H.

All material used for the specimens will be taken from the actual production forging, and from a weldment made of the same weld wire heat and flux lot combination used in the production weld. The limiting base metal is expected to be the lower RPV shell forging. However, unit-specific limiting base metal will be based on actual forging chemistry and initial RT_{NDT}, and can be either the lower RPV shell or the RPV bottom head forging. The predicted limiting weld metal is the lower RPV shell to bottom head circumferential weld. The predicted limiting heat affected zone is the region of the predicted limiting base metal next to the weld.

In accordance with ASTM E185-82, archive materials fill at least two capsules. The archived materials are the same limiting materials used to machine the baseline and capsule specimens, except the archive materials will be maintained as full-thickness sections during plant operating life. The purpose of archive materials is to fabricate additional capsules for unforeseeable contingencies, such as to monitor the effect of a major core change. Because the preferred type and size of specimens may change with time, the archive materials are maintained as full-thickness sections instead of being machined into specimens. Therefore, the archive materials for Reactor Pressure Vessel Surveillance Program are taken from the actual production forgings, and from weldments made from the same weld wire heat and flux lot combination used in the production weld.

Table 5.3-4 lists the specimen matrix for the Material Surveillance program requirements. As shown in the table, the number of specimens meets the ASTM E185-82 (Reference 5.3-6) minimum requirements.

The NuScale reactor vessel is designed for 60 years. Therefore, for the first 40 years of the 60-year design life, the capsule withdrawal schedule complies with Table 1 of ASTM E185-82, which is based on 32 effective full-power years (EFPY). Three capsules are sufficient to cover the initial 40-year operation per E185-82. The capsule withdrawal schedule is provided in Table 5.3-5.

The capsules are inside capsule holders that are attached to the outside of the core barrel at mid-height of the core. The capsules are positioned to achieve a lead factor of approximately 2.5. The four capsules are positioned approximately 90 degrees apart around the circumference of the core support assembly. Figure 5.3-2 shows the core barrel horizontal cross-section and the location of the four capsule holders and capsule elevation on the core barrel.

The neutron flux and fluence calculation methods are consistent with the guidance of RG 1.190 with exceptions as described in NuScale Technical Report TR-0116-20781, "Fluence Calculation Methodology and Results" (Reference 5.3-7).

The transition temperature upper shelf energy changes are calculated in accordance with RG 1.99, and are shown in Table 5.3-8, Table 5.3-9, and Table 5.3-10. Section 5.3.2 provides further information.

COL Item 5.3-3: A COL applicant that references the NuScale Power Plant design certification will describe the reactor vessel material surveillance program consistent with NUREG 0800, Section 5.3.1.

5.3.1.7 Reactor Vessel Fasteners

The RPV closure studs, nuts, and washers use SB-637 Alloy 718, instead of low alloy steels such a SA-540 Grade B23 or B24. The selection of Alloy 718 over traditional low alloy steels is to prevent general corrosion when the bolting is submerged during the plant startup and shutdown process. Because of its resistance to general corrosion, the concerns addressed by RG 1.65, Revision 1, position 2(b) do not apply to Alloy 718. Alloy 718 is an austenitic, precipitation-hardened, nickel-based alloy permitted for bolting materials by ASME BPVC Section III (Reference 5.3-1), Subsection NB-2128.

Furthermore, because Alloy 718 is not a ferritic material, the fracture toughness requirements of NB-2333 are not required. Further information is provided in Section 3.13.

Threaded inserts are used for RPV threaded fasteners except for the main RPV flange studs and steam generator inlet flow restrictor hardware. The threaded inserts used for threaded fasteners are externally threaded in addition to being internally threaded such that the inserts are threaded into the associated base metal. As such, the external threads on the inserts and internal threads in the flange bolt holes are designed to carry mechanical loads during normal and off-normal operations, including ECCS actuation. See Table 5.2-4 for threaded insert materials and applicable specifications. The fabrication inspections for threaded inserts are based on ASME BPVC Section III (Reference 5.3-1), Subsection NB-2580, using the outer diameter of the threaded insert for sizing requirements.

For the RPV flange connection, lock plates are used to perform a tooling function to hold the RPV flange nut in place, on top of the flange, after the flange stud is removed or while the flange stud is installed. The lock plates are not considered part of the reactor coolant pressure boundary. The lock plates only resist the minor friction loads and forces that occur when inserting and threading the studs into the nuts and do not resist the forces applied to tension the stud. The sames is true for removing and detensioning the studs.

The lock plates are held in place by studs that are attached with a stud weld to the top of the flange cladding. The welded studs used to retain the lock plates are nonstructural attachments as defined in ASME BPVC section NB-1132.1(c)(2), similar to insulation supports. The lock plates are not considered an attachment to the RPV per the ASME code.

The stud weld to the cladding requires a cladding preservice liquid penetrant exam, per ASME BPVC section NB-5272, Weld Metal Cladding. The stud weld to the cladding also complies with ASME BPVC section NB-4435, Welding of Nonstructural Attachments.

There are no inservice exam requirements for the lock plate stud welds or the lock plates.

5.3.2 Pressure-Temperature Limits, Pressurized Thermal Shock, and Charpy Upper-Shelf Energy Data and Analyses

Analyses

The information provided in this section describes the bases for setting operational limits on pressure and temperature for the RCPB and ensures the requirements of 10 CFR 50, Appendices G and H, and 10 CFR 50.61 are complied with throughout the 60-year life of the plant.

5.3.2.1 Limit Curves

Using the methodology provided in ASME BPVC Section XI, Appendix G, and the requirements in 10 CFR 50 Appendix G, a generic set of pressure-temperature limits at 57 EFPY is calculated for various conditions. The methodology also accounts for vessel embrittlement due to neutron fluence in accordance with RG 1.99. The pressure-temperature limits for normal heatup and criticality conditions, normal cooldown, and inservice leak and hydrostatic tests are provided in Figure 5.3-3, Figure 5.3-4, and Figure 5.3-5, respectively. The corresponding numerical values are listed in Table 5.3-6 and Table 5.3-7. These pressure-temperature curves meet the pressure and temperature requirements for the RPV listed in Table 1 of 10 CFR 50, Appendix G. The RCS pressure should be maintained below the limit of the pressure-temperature limit curves to ensure protection against non-ductile failure. Acceptable pressure and temperature combinations for reactor vessel operation are below and to the right of the applicable pressure-temperature curves. These pressure-temperature curves do not include any location correction or instrument uncertainty. For the purpose of location correction, the allowable pressure in the pressure-temperature curves can be taken as the pressure at the RPV bottom. The reactor is not permitted to be critical until the pressure-temperature combinations are to the right of the criticality curve shown in Figure 5.3-3.

The ΔRT_{NDT} at the 1/4 -T adjusted reference temperature at end of life is provided in Table 5.3-3, as described in Section 5.3.1.5.

Further information on the specific methodology is provided in NuScale Technical Report TR-1015-18177, "Pressure and Temperature Limits Methodology" (Reference 5.3-8).

5.3.2.2 Operating Procedures

Development of plant operating procedures to ensure that the pressure-temperature limits are not exceeded is addressed in Section 13.5. These procedures will ensure compliance with the technical specifications during normal power operating conditions and anticipated transients.

COL Item 5.3-2: A COL applicant that references the NuScale Power Plant design certification will develop operating procedures to ensure that transients will not be more severe than those for which the reactor design adequacy had been demonstrated. These procedures will be based on material properties of the as-built reactor vessels.

5.3.2.3 Pressurized Thermal Shock

The pressurized thermal shock (PTS) screening uses the methodology in 10 CFR 50.61. The attenuated fluence below the inside diameter cladding surface and the temperature factor for RT_{NDT} shift (including the nominal irradiation temperature correction factor) are calculated using the RG 1.99 equations. As shown in Table 5.3-8, the predicted RT_{PTS} remains below the 10 CFR 50.61 PTS screening criteria at 32-EFPY fluence and at 57-EFPY fluence, which bounds the NuScale 60-year design life.

5.3.2.4 Upper-Shelf Energy

Reactor vessel beltline materials are evaluated to ensure a minimum end-of-life Charpy V-notch upper shelf energy value of 50 ft-lb, as required by 10 CFR 50, Appendix G, at 57-EFPY fluence, which bounds the NuScale 60-year design life. The initial Charpy V-notch upper shelf energy value is 75 ft-lb. The predicted 1/4-T Charpy upper shelf energy decrease per RG 1.99 is summarized in Table 5.3-9. The predicted 1/4-T Charpy upper shelf energy after adjusting for NuScale RPV irradiation temperature is summarized in Table 5.3-10. Only the 57-EFPY fluence is calculated as it represents the most limiting case.

5.3.3 Reactor Vessel Integrity

5.3.3.1 Design

Compatibility of the RPV design with established standards is described in Section 5.3.1. The basic design of the RPV establishes compatibility with required inspections as described in Section 5.2.4 and Section 5.3.1.

5.3.3.2 Materials of Construction

The reactor vessel materials of construction are described in Section 5.2.3 and Section 5.3.1.

5.3.3.3 Fabrication Methods

The fabrication methods used in the construction of the reactor vessel are described in Section 5.2.3 and Section 5.3.1.

5.3.3.4 Inspection Requirements

The nondestructive examinations performed are described in Section 5.3.1.

5.3.3.5 Shipment and Installation

Packaging, shipment, handling, and storage of the RPV is in accordance with ASME BPVC, Section III, 2013 edition, subsection NCA-4134.13 and meet the requirements for Level C items in accordance with ASME NQA-1-2008/1a-2009 Addenda (Reference 5.3-2), subpart 2.2.

A dry environment is maintained for all RPV surfaces, both primary and secondary sides, by an installed non-chloride, non-corrosive desiccant. The RPV is shipped with humidity indicators covering a suitable range of moisture content. The RPV is shipped with both the primary and secondary sides under positive pressure. The internal atmosphere on both sides of the SG tubes are evacuated to eliminate residual moisture and filled with nitrogen having a dew point less than -20 degrees F.

Appropriate foreign material exclusion measures are taken in preparation for shipping the RPV.

5.3.3.6 Operating Conditions

Operating conditions as they relate to the integrity of the reactor vessel are presented in Section 5.2.2 and Section 5.3.2 and the plant technical specifications.

5.3.3.7 Inservice Surveillance

Inservice surveillance of the RPV is described in Section 5.2.4 and Section 5.3.1.

5.3.3.8 Threaded Fasteners

Threaded fasteners are discussed in Section 3.13 and Section 5.3.1.

5.3.4 References

5.3-1 American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, "Rules for Construction of Nuclear Facility Components," 2013 Edition, Section III, New York, NY.

5.3-2 American Society of Mechanical Engineers, Quality Assurance Requirements for Nuclear Facility Applications, ASME NQA-1-2008/1a-2009 Addenda, New York, NY.

5.3-3 ASTM International, "Standard Practices for Detecting Susceptibility to Intergranular Attack in Austenitic Stainless Steels," ASTM A262-15, West Conshohocken, PA.

5.3-4 Not Used

5.3-5 American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, “Rules for Inservice Inspection of Nuclear Power Plant Components," 2013 edition, Section XI, New York, NY.

5.3-6 ASTM International, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," ASTM E185-82, West Conshohocken, PA.

5.3-7 NuScale Power, LLC, "Fluence Calculational Methodology and Results," TR-0116-20781, Rev. 0.

5.3-8 NuScale Power, LLC, "Pressure and Temperature Limits Methodology," TR-1015-18177, Rev. 1.

Table 5.3-1: Reactor Vessel Parameters

Design Parameter	Value
Design pressure (psia)	2100
Design temperature (degrees F)	650
Overall height, bottom of alignment feature to top of CRDM latch housing section (inches)	778
Inside diameter of lower RPV section, cylindrical region, without clad (inches)	96.5
Outside diameter of lower RPV section, cylindrical region, without clad (inches)	105
Inside diameter of upper RPV section, cylindrical region, without clad (inches)	104.5
Outside diameter of upper RPV section, cylindrical region, without clad (inches)	112.5
Inside diameter of pressurizer, cylindrical region, without clad (inches)	106.5
Outside diameter of pressurizer, cylindrical region, without clad (inches)	115.5
Inside diameter of upper head without clad (inches)	104.5
Outside diameter of upper head without clad (inches)	112.5
Inner clad thickness (inches)	0.25
Outer clad thickness (inches)	0.125

Table 5.3-2: Chemical Composition of Reactor Pressure Vessel Beltline Materials

Material	Element	Maximum concentration (wt%)
RPV beltline forging material	Sulfur	0.010
	Phosphorus	0.010
	Copper	0.06
	Cobalt	0.05
	Nickel	0.85
As-deposited weld metal used in the RPV beltline	Sulfur	.015
	Phosphorus	.012
	Copper	.06
	Cobalt	.05
	Manganese	1.80
	Nickel	0.85

Table 5.3-3: 1/4-T Adjusted Reference Temperature Result at 57 Effective Full-Power Years Fluence

Location	Peak 1/4-T Fluence, n/cm^2, E >1 MeV	Maximum Initial RT_{NDT} (°F)	ΔRT_{NDT} (°F)	Margin (°F)	Adjusted Reference Temperature (°F)
Lower RPV shell, beltline	1.37E+19	-10	68.2	34.0	92.2
Lower RPV weld	3.21E+18	-20	84.4	56.0	120.4
RPV bottom head	3.21E+18	-10	53.4	34.0	77.4

Table 5.3-4: Material Specimen Program Matrix per ASTM E185-82

Material	Charpy		Tension	
	E185-82	NuScale	E185-82	NuScale
Unirradiated Specimen Matrix, Baseline				
Limiting forging	18 min	18	3 min	3
Limiting weld	18 min	18	3 min	3
Limiting heat-affected zone	18 min	18	N/A	N/A
Irradiated Specimen Matrix, per capsule				
Limiting forging	12 min	15	3 min	3
Limiting weld	12 min	15	3 min	3
Limiting heat-affected zone	12 min	15	N/A	N/A

Table 5.3-5: Surveillance Capsule Withdrawal Schedule

Sequence	ASTM E185-82 Withdrawal Requirement [(a)]	Estimated Withdrawal
1st	Whichever comes first • 6-EFPY • Capsule fluence > 5E+18 n/cm^2, E > 1 MeV • Highest predicted ΔRT_{NDT} > ~50°F of all encapsulated materials	First refuel outage (~2 EFPY) when highest predicted ΔRT_{NDT} > ~50°F[(b)]
2nd	Whichever comes first • 15 EFPY • Capsule fluence > peak 32-EFPY RPV inside surface fluence	~13 EFPY for capsule fluence to reach peak 32-EFPY RPV inside surface fluence • 32 EFPY/2.5 = ~13 EFPY
3rd	Capsule fluence is between 1 and 2 times of peak 32-EFPY inside surface fluence	Between ~13 EFPY and ~26 EFPY • 32 EFPY/2.5 = ~13 EFPY • 64 EFPY/2.5 = ~26 EFPY
4th	Not required by ASTM E185-82	Withdrawal of the 4th capsule will be determined by applicable regulation at the time of license extension application.

Notes:

a. The withdrawal schedule for the first three capsules is in accordance with ASTM E185-82 for the initial 40-year operating license period. The 4th capsule is not required by ASTM E185-82 for the 40-year license.

b. The highest predicted ΔRT_{NDT} material to reach 50°F is the limiting weld metal at 4.27+17 n/cm^2, E > 1 MeV (or 0.55 EFPY). However, 28°F of the 50°F shift is due to a "1°F/1°F below 525°F irradiation temperature" adjustment. The 28°F adjustment is fixed irrespective of changes in fluence, therefore, overcompensates at low fluence levels. It is considered unlikely that weld metal specimens will reach 50°F shift at 0.55 EFPY. Therefore, the first capsule can be withdrawn at the end of the first fuel cycle (2 EFPY or 1.55E+18 n/cm^2, E > 1 MeV), instead of mid-fuel-cycle.

Table 5.3-6: Pressure-Temperature Limits for Normal Heatup and Cooldown

Normal Heat up (Core Not Critical)		Normal Heat up (Core Critical) (Minimum core critical temperature determined from the transient ISLH curve)		Normal Heat up (Core Critical) (Minimum core critical temperature determined from the Steady-State ISLH curve)		Normal Cooldown	
Fluid Temp. (°F)	**Press. (psig)**	**Fluid Temp. (°F)**	**Press. (psig)**	**Fluid Temp. (°F)**	**Press. (psig)**	**Fluid Temp. (°F)**	**Press. (psig)**
40	515	(Reactor is not permitted to be critical below 287°F if ISLH testing is performed at Heat up/Cooldown transient conditions)		(Reactor is not permitted to be critical below 185°F if ISLH testing is performed at steady-state conditions.)		309	2759
52	516					300	2187
62	518					292	1697
78	523					285	1439
94	525					276	1280
104	525					268	1168
114	525			185	0	260	1071
125	525			185	150	252	1011
135	525			185	300	243	966
146	525			185	400	239	932
166	525			185	525	235	906
175	525			223	705	232	884
176	525			241	796	229	865
176	676	287	0	258	927	226	848
183	705	287	500	276	1115	223	833
201	796	287	750	295	1414	213	795
218	927	287	1000	314	1864	187	743
236	1115	287	1293	334	2518	176	720
255	1414	295	1414	354	2752	176	525
274	1864	314	1864	374	2750	162	525
294	2518	334	2518	393	2749	156	525
314	2752	354	2752	413	2747	156	525
334	2750	374	2750	426	2745	121	525
353	2749	393	2749	440	2742	118	525
373	2747	413	2747	454	2740	91	525
386	2745	426	2745	462	2735	79	525
400	2742	440	2742	469	2732	73	525
414	2740	454	2740	470	2729	73	525

Table 5.3-7: Pressure-Temperature Limits for Inservice Leak and Hydrostatic Test

ISLH for Heat up Transient		ISLH for Cooldown Transient		Transient ISLH (Bounding of Heat up/Cooldown)		Steady-State ISLH	
Fluid Temp. (°F)	Press. (psig)	Fluid Temp. (°F)	Press. (psig)	Fluid Temp. (°F)	Press. (psig)	Fluid Temp. (°F)	Press. (psig)
79	525	300	2916	79	525	40	525
91	525	292	2262	91	525	52	525
118	525	285	1918	118	525	62	525
121	525	276	1707	121	525	78	525
146	525	268	1557	146	525	94	525
146	790	260	1429	146	790	104	525
156	823	252	1348	156	823	114	525
156	823	243	1288	156	823	125	525
162	843	239	1243	162	843	135	525
187	968	235	1207	187	968	146	525
213	1185	232	1178	213	1060	146	525
223	1298	229	1153	223	1111	146	1247
226	1343	226	1130	226	1130	166	1556
229	1389	223	1111	229	1153	175	1737
232	1434	213	1060	232	1178	183	1952
235	1479	187	991	235	1207	201	2514
239	1552	162	922	239	1243	218	3312
243	1640	156	886	243	1288		
252	1814	156	849	252	1348		
260	2042	146	837	260	1429		
268	2293	146	525	268	1557		
276	2576	121	525	276	1707		
285	2960	118	525	285	1918		
292	3296	91	525	292	2262		
300	3459	79	525	300	2916		

Table 5.3-8: Pressurized Thermal Shock Screening Result

	0-T Fluence n/cm^2, E > 1 MeV	Max Initial RT_{NDT} (°F)	ΔRT_{NDT} (°F)	Margin (°F)	RT_{PTS} (°F)	Screening Criterion (°F)
(32-EFPY Fluence)						
Lower RPV shell, beltline	9.94E+18	-10	64.9	34.0	88.9	270 max
Lower RPV weld	2.32E+18	-20	77.6	56.0	113.6	300 max
RPV bottom head	2.32E+18	-10	50.4	34.0	74.4	270 max
(57-EFPY Fluence)						
Lower RPV shell, beltline	1.77E+19	-10	70.8	34.0	94.8	270 max
Lower RPV weld	4.14E+18	-20	89.9	56.0	125.9	300 max
RPV bottom head	4.14E+18	-10	55.9	34.0	79.9	270 max

Table 5.3-9: 1/4-T Charpy Upper Shelf Energy per RG 1.99, Rev. 2

	Cu, wt%	¼-T, 57-EFPY Fluence n/cm^2, E > 1 MeV	Charpy Upper Shelf Energy Decrease	Initial Charpy Upper Shelf Energy, min	Charpy Upper Shelf Energy per RG 1.99 Rev 2, min
Lower RPV shell, beltline	0.10 [(a)]	1.37E+19	20.5%	75 ft-lb	59.6 ft-lb
Lower RPV weld	0.06	3.21E+18	15.3%	75 ft-lb	63.5 ft-lb
RPV bottom head	0.10 [(a)]	3.21E+18	14.5%	75 ft-lb	64.1 ft-lb

Note:
(a) For base metal, the 0.10 wt% Cu line is the minimum line in Figure 2 of Regulatory Guide 1.99, Rev. 2. For conservatism, 0.10% Cu is used instead of the maximum 0.06 wt% Cu for the NuScale design.

Table 5.3-10: 1/4-T Charpy Upper Shelf Energy after Adjusting for NuScale Reactor Pressure Vessel Irradiation Temperature

	Final Charpy Upper Shelf Energy per RG 1.99 Rev 2	Irradiation Temperature Adjustment	Final Charpy Upper Shelf Energy
Lower RPV shell, beltline	59.6 ft-lb min	-1.2 ft-lb	58.4 ft-lb min
Lower RPV weld	63.5 ft-lb min	-1.2 ft-lb	62.3 ft-lb min
RPV bottom head	64.1 ft-lb min	-1.2 ft-lb	62.9 ft-lb min

Figure 5.3-1: Reactor Vessel

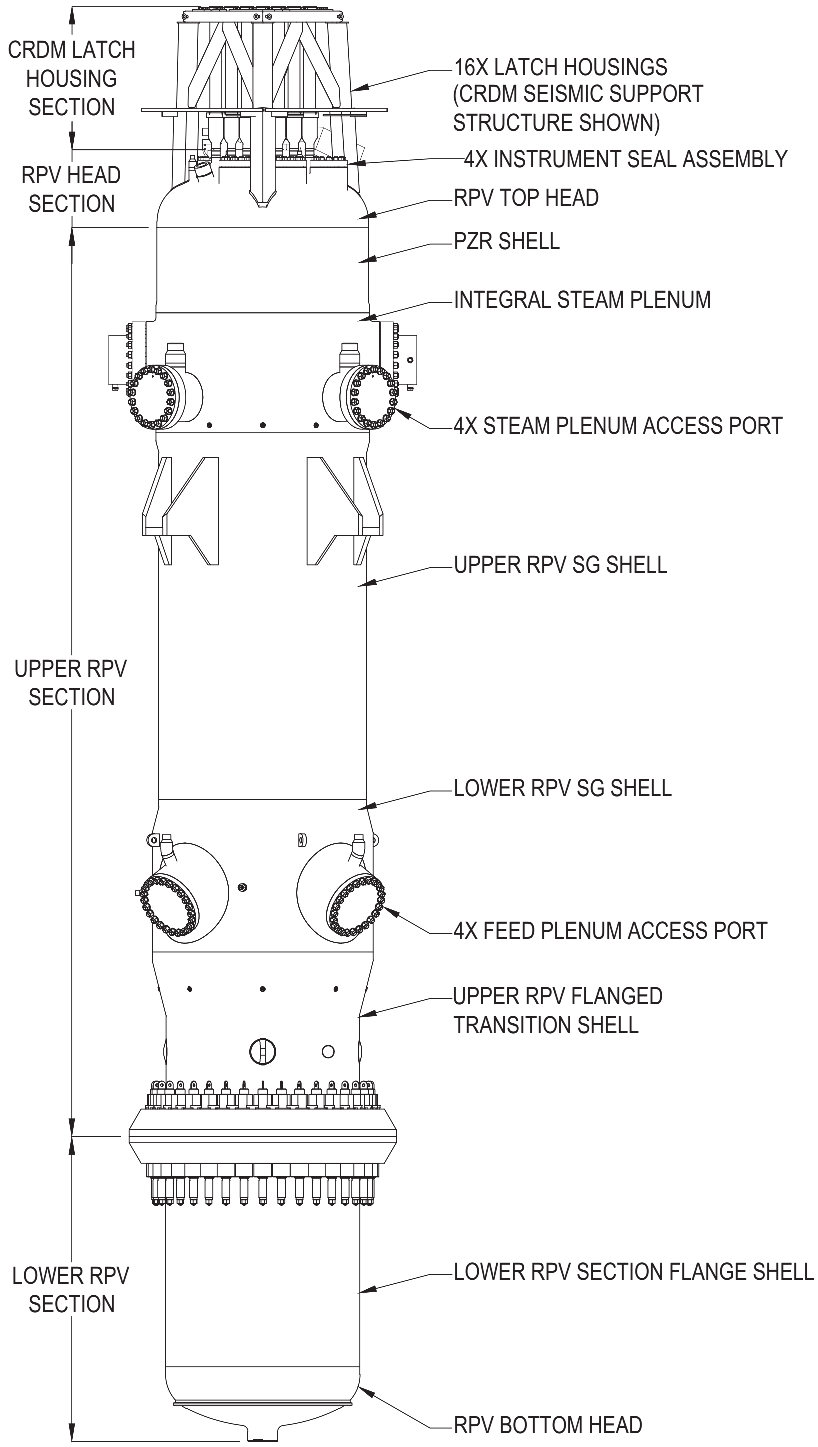


Figure 5.3-2: Location of Surveillance Capsules

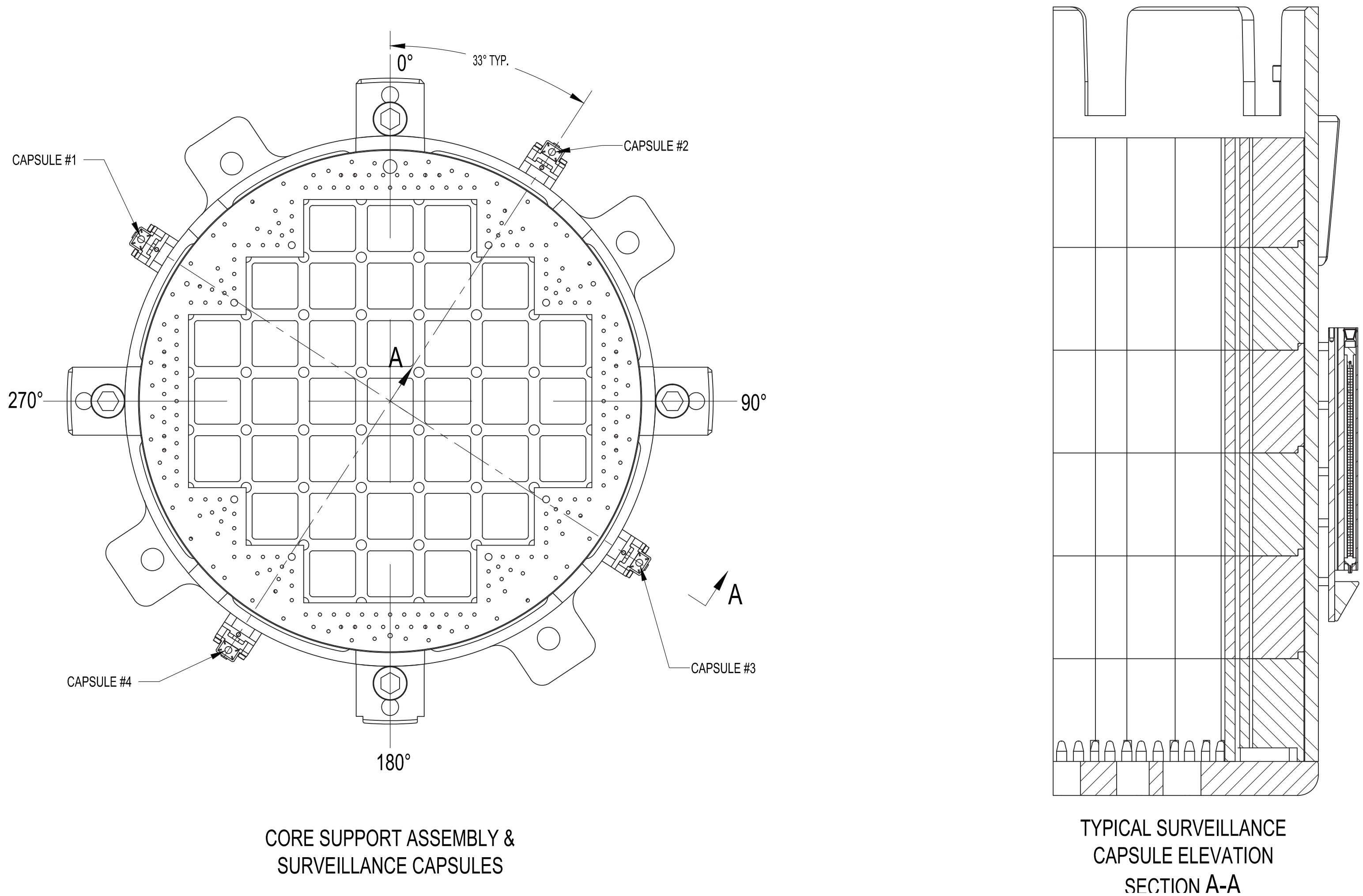


Figure 5.3-3: Pressure-Temperature Limits for Normal Heatup and Criticality Limit

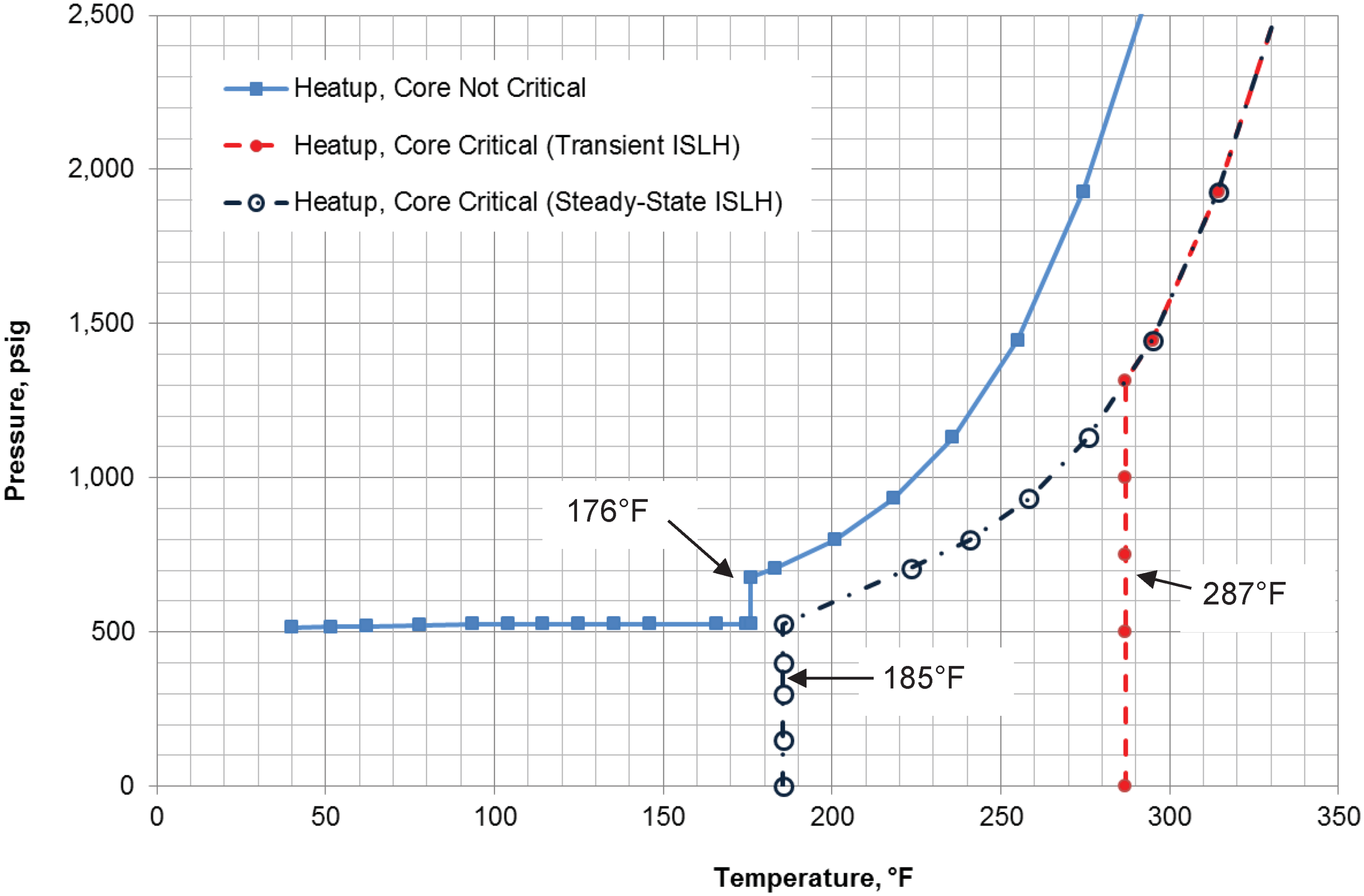


Figure 5.3-4: Pressure-Temperature Limits for Normal Cooldown with Decay Heat Removal and Containment Vessel Flooding

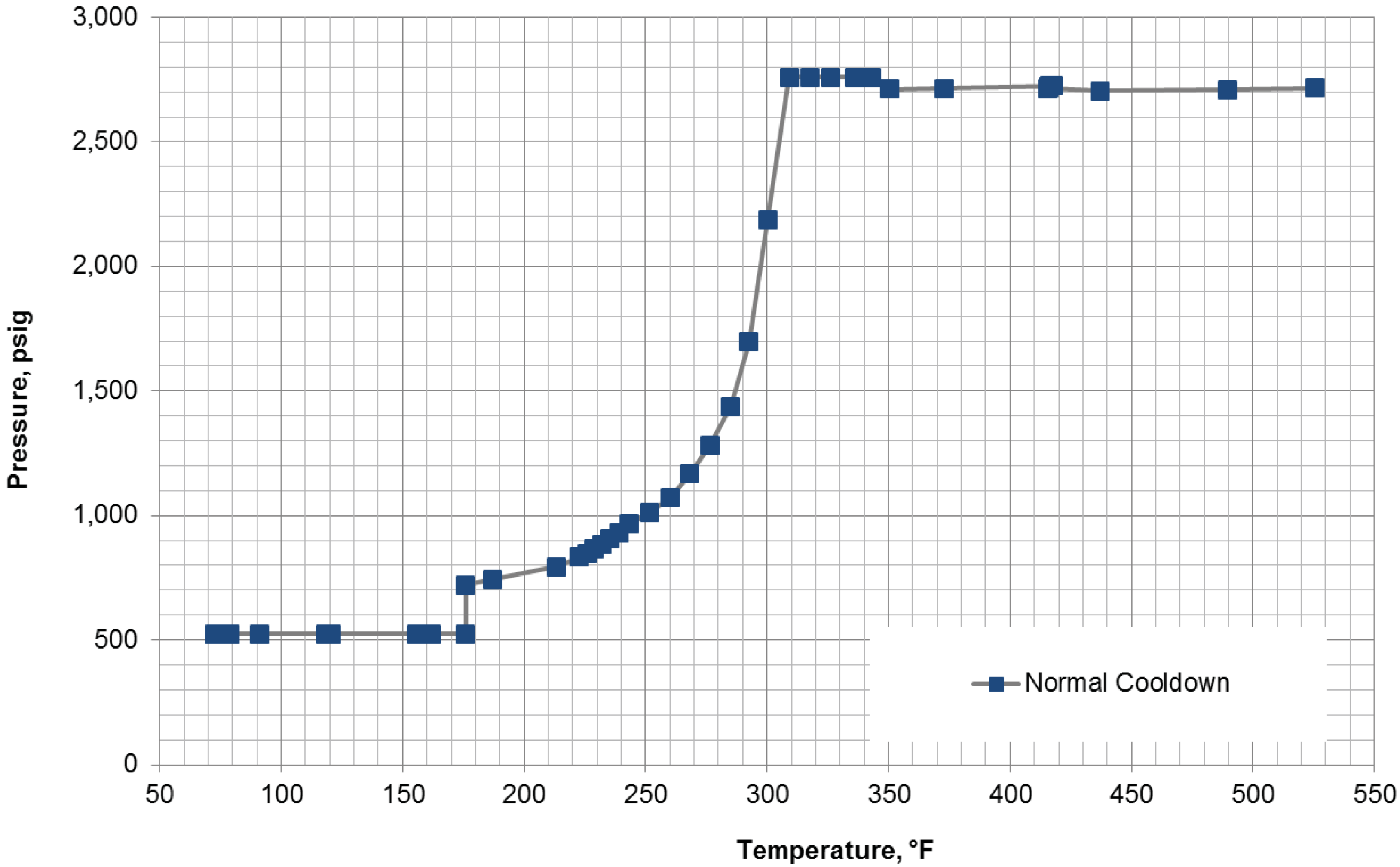
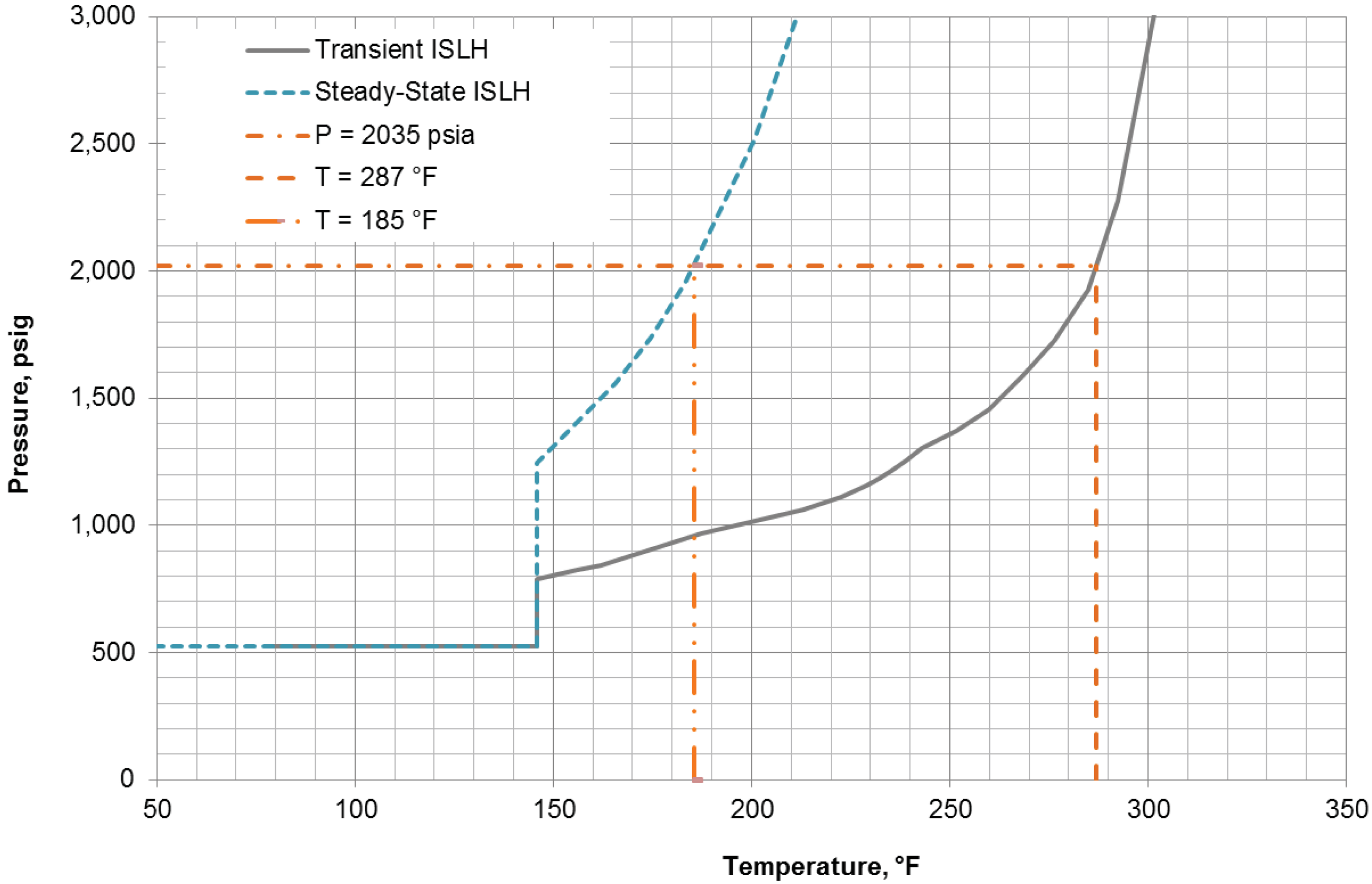


Figure 5.3-5: Pressure-Temperature Limits for Inservice Leak and Hydrostatic Tests



5.4 Reactor Coolant System Component and Subsystem Design

The reactor pressure vessel (RPV) of each integrated NuScale Power Module (NPM) contains the reactor and reactor vessel internals; a pressurizer; two steam generators (SGs); reactor safety valves (RSVs); emergency core cooling system (ECCS) valves; reactor coolant system (RCS) injection, discharge, pressurizer spray, and high-point degasification vent lines; and a decay heat removal system (DHRS).

The design basis and description of the reactor and reactor vessel internals are provided in Chapter 4. The design basis and description of the RSVs are provided in Section 5.2.2 and the design basis and description of the ECCS valves (i.e., reactor vent valves (RVVs) and reactor recirculation valves (RRVs)) are provided in Section 6.3 and Section 5.2.2.

5.4.1 Steam Generators

The steam generator system (SGS) consists of: the FW piping from the CNTS to the feed plenum access port; thermal relief valve; feed plenum access port and access cover; steam generators (SGs); steam plenum cap; steam plenum access port and access cover; and MS piping from the steam plenum access port to the CNTS. The FW plenum is within the feed plenum access port with the tube sheet forming the boundary between the primary and secondary side. The MS plenum is within the RPV integral steam plenum shell with the steam plenum cap and RPV integral baffle plate forming the boundary between the primary and secondary side. The FW piping, thermal relief valve, steam plenum access port, and MS piping of the SGS form the secondary side of the SGS.

The SGs in the NPM are integral to the RPV. The RPV forms the SG shell and provides the outer pressure boundary of the SGs. The steam generator tube, tube-to-tubesheet welds, and tubesheets provide part of the reactor coolant pressure boundary (RCPB). Refer to Section 5.2 and Section 5.3 for description and design basis information regarding the RPV and the RCPB.

5.4.1.1 Design Basis

The SGs transfer sensible heat from the RCS to the secondary steam system and supply superheated steam to the steam and power conversion cycle as described in Chapter 10.

Table 5.4-1 provides a summary of the operating conditions for thermal-hydraulic design of the SGs. The secondary plant parameters represent full-power steam flow conditions at the outlet of the steam plenums at best estimate primary coolant conditions.

The SGs provide sufficient stable flow on the secondary side of the tubes at operational power levels and mass flow rates to preclude reactor power oscillations that could result in exceeding specified acceptable fuel design limits.

The secondary flow oscillation magnitude is limited by flow restriction devices at the secondary side inlet of each individual SG tube.

The SGs also provide two primary safety-related functions: they form a portion of the RCPB and they transfer decay heat to the DHRS described in Section 5.4.3.

The portions of the SGs that form a part of the RCPB provide one of the fission product barriers. In the event of fuel cladding failure, the barrier isolates radioactive material in the reactor coolant preventing release to the environment.

The SGs perform an integral part of the reactor residual and decay heat removal process when the DHRS is in operation. They transfer heat from the primary coolant to the naturally circulating closed loops that transfer decay heat to the reactor pool.

10 CFR 50.55a(g) requires the inservice inspection (ISI) program to meet the applicable inspection requirements of Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC). The steam generator system (SGS) components are designed such that the ISI requirements of ASME BPVC, Section XI can be performed, including the preservice inspections of ASME Section III. A SG program, based on NEI 97-06 (Reference 5.4-1) and Regulatory Guide 1.121 is described in Section 5.5.4 of the technical specifications, and implements ASME Code Section III and XI for the SG tubes. The primary and secondary sides of the SGs are designed to permit implementation of a SG program that provides reasonable assurance the structural and leakage integrity of the SG tubes is maintained. Integrity of SGs, integral steam plenum, and feedwater plena that make up portions of the RCPB is discussed in Section 5.2.

5.4.1.2 System Design

Each SG, located inside the RPV, is comprised of interlacing helical tube columns connecting to two feed and two steam plena. The feed and steam plena comprising a single SG are configured 180 degrees apart. As shown in Figure 5.4-1 and Figure 5.4-2, the configuration of the helical tube columns of the two SGs form an intertwined bundle of tubes around the upper riser assembly with a total of four feed and four steam plena located 90 degrees apart around the RPV. Figure 5.4-3 shows the cross-sectional arrangement of the integral steam plena and feed plena, while Figure 5.4-4 and Figure 5.4-5 show individual cross-sectional views of an individual steam and feed plenum. The main steam supply nozzles and the feedwater supply nozzles are also part of the SGS. Each SG has a pair of feedwater and main steam supply nozzles. The main steam supply nozzles are integral to the steam plenum access ports and the feedwater supply nozzles are integral to the feed plenum access ports as shown in Figure 5.4-4 and Figure 5.4-5, respectively. The primary reactor coolant circulates outside the SG tubes with steam formation occurring inside the SG tubes.

Each SG tube is comprised of a helix with bends at each end that transition from the helix to a straight configuration at the entry to the tubes sheets as shown in Figure 5.4-1. The helical tubes are seamless with no intermediate welds. The helical tubes terminate at the feed and steam plenum tubesheets, where the tubes are secured to the tubesheet by expansion fit and are welded to the tubesheet on the secondary side. Crevices between the SG tubes and the tube supports and tubesheets are minimized to limit the buildup of corrosion products. Minimal quantities of corrosion products are present because the SG tube-to-tubesheet contact is within the primary coolant environment. Crevices at the tube-to-tubesheet face are prevented by full-length expansion of the tube within the tubesheet bore. The tubes are expanded into both the steam and feed plenum tubesheets.

The SG has no secondary side crevices or low-flow regions that could concentrate corrosion products or impurities accumulated during the steam generation process. The once-through SG design does not contain a bulk reservoir of water at the inlet plena where the accumulation or concentration of material could occur. The concept of SG blowdown to remove these deposits is not applicable to the once-through NuScale Power Module SG design based on the geometry of the design and flow characteristics that do not allow accumulation of corrosion products within a fluid reservoir. Therefore, a blowdown system that could be implemented would only serve to divert feedwater flow from the SG and would not be capable of removing corrosion products or impurities. Based on these factors, no SG blowdown system is included in the NPM design.

Secondary coolant impurities and corrosion products may deposit directly on the interior tube surfaces as a scale or film, or be removed from the SG by carryover. The concentration of corrosion products and impurities is low based on selection of materials for the condensate system and chemistry control requirements. An unacceptable buildup of corrosion product films on the secondary surfaces of the SG tubes is removed through periodic cleaning performed during outage periods. The cleaning methods and techniques are based on proven chemical or mechanical methods already employed in the pressurized water reactor existing fleet.

Secondary side SG surfaces are corrosion resistant, either nickel alloy, stainless steel, or stainless steel clad, which removes the concern for degradation of the SG shell or other low-alloy or carbon steel material by cleaning solutions. No low-flow areas exist for the buildup of hard sludge piles, which would require water lancing or other invasive techniques. Cleaning of the SG is readily accomplished by connecting an appropriate system directly to the main steam and feedwater disconnect flanges during an outage.

Heated primary coolant from the reactor core exits the riser and flows down the outer annulus through the SG tubes where heat is transferred to secondary coolant inside the SG tubes. The primary coolant continues to flow down through the annular downcomer below the SGs into the lower reactor vessel plenum, where it reenters the reactor core. Further discussion of the RCS is provided in Section 5.1 and the RCS loop flow is illustrated in Figure 5.1-3.

The SGs deliver superheated steam with moisture content no greater than 0.10 percent by weight during full-power operating conditions.

Feedwater is supplied to the SGs by piping from the feedwater and condensate system located outside the Reactor Building. The feedwater lines are routed to and through the containment vessel (CNV) and into the lower SG plena, which penetrate the RPV wall. Feedwater flows from each feed plenum through the bottom of the SG tube columns, upward and around the outside of the upper riser assembly, and is converted to steam by the heat transferred from the reactor coolant.

The steam plena collect steam from the top of the SG tube columns and direct the steam through the steam nozzles. Steam flows through the SG piping, through nozzles penetrating the containment, and then to the main steam system and power conversion systems located outside the Reactor Building.

The total SG heat transfer area provided in Table 5.4-2 comprises the outer surface area of the full length of tubes from the outer face of the feed plenums to the outer face of the steam plenums. The total heat transfer area of each of the two independent SGs includes a 10 percent tube plugging margin.

A fouling factor is used when calculating end-of-cycle heat transfer performance and is provided in Table 5.4-2. The value is selected to account for typical operating experience for nuclear power plants that maintain the secondary system chemistry within the limits of the plant secondary water chemistry control program. The fouling factor is applied to the tube inner surface where deposits of steam plant corrosion products occur. The thin oxide layer that develops on the outer surface of the tubes in the primary coolant is not considered in tube heat transfer fouling.

The SG tubes are designed with a nominal wall thickness of 0.050 inch. A lifetime degradation allowance of 0.010 inch is included in the design nominal wall thickness. SG tube wall thickness is selected to account for random inservice tube degradation mechanisms (e.g., general corrosion, erosion, and wear) and tube defects introduced during the SG assembly process.

The SG design data is provided in Table 5.4-2. Transient conditions applicable to the SGs are discussed in Section 3.9.1 and design stress limits, loads, and load combinations applicable to the SGs are discussed in Section 3.9.3. NuScale SG degradation evaluations demonstrate that the SG tubing retains acceptable tube integrity with 50 percent thickness degradation under all loading conditions.

Main steam isolation valves (MSIVs) and feedwater isolation valves (FWIVs) are located outside the NPM on the main steam and feedwater headers, respectively, on top of the CNV at the top support structure platform. A detailed discussion of the isolation functions of the valves is provided in Section 6.2.4.

The DHRS forms a closed-loop connection between the steam lines and the feedwater lines inside the containment isolation boundary formed by the MSIVs and FWIVs. The DHRS is isolated from steam flow during normal operations by the DHRS actuation valves. The DHRS is described in more detail in Section 5.4.3.

The SGs are designed to minimize tube corrosion, to minimize tube vibration and wear, and to enhance overall reliability. The design includes provisions to reduce the potential for tube damage due to loose parts wear.

The SG design permits periodic inspection and testing of critical areas and features to assess their structural and pressure boundary integrity when the NPM is disassembled for refueling as shown in Figure 5.4-2. The internal surface of SG tubes is accessible over their entire length for application of nondestructive examination methods and techniques that are capable of finding the types of degradation that may occur over the life of the tubes. Individual SG tubes may be plugged, and if necessary, stabilized to prevent adverse interaction with non-plugged tubes. Access to the internal (secondary) and external (reactor coolant) sides of tubesheets affords opportunity for inspection, and for removal of foreign objects. See Figure 5.4-4 and Figure 5.4-5 for an illustration of the steam and feed plena inspection ports.

The FW plenum and MS plenum SGS subcomponents and SG tubes that form portions of the RCPB are classified Quality Group A and are designed, fabricated, constructed, tested and inspected as Class 1 in accordance with Section III of the BPVC. Steam and feedwater piping between the CNTS and RPV, including those portions that interface with and support operation of the DHRS, are designed, fabricated, constructed, tested and inspected as Class 2 in accordance with the BPVC, Section III. The SGS and connected components up to the CNTS are Seismic Category I components. Details of the SG classification designations and the scope of their applicability are provided in Table 3.2-1. Chapter 3 provides detailed information regarding the design basis and qualification of structures, systems, and components based on these classifications and designations. Figure 6.6-1 shows the BPVC Section III, Class 1 and 2 boundaries for the SGS.

<u>Steam Generator Tube Supports and Steam Generator Supports</u>

Based on the use of seamless helical tubing to comprise the tube bundle, typical SG tube support plates are not used. Instead, the NPM steam generator employs a system of austenitic stainless steel tube support assemblies. The design of the stainless steel supports includes full-circumferential support of the tubes. The circumferential support is not continuous and therefore limits the potential for crevices between the tube and support. By choosing materials that limit the potential for generation and buildup of corrosion products and a geometry that minimizes crevices and facilitates flow (further limiting potential for corrosion product buildup), two of the most significant historical contributors to tube degradation by the tube supports are precluded.

The tube support assemblies are located between each column of helical tubes. Stamped tabs in the tube supports envelope part of the circumference of tubes both above and below, and provide vertical tube support as shown in Figure 5.4-7. The overall design of the tube support assemblies and tabs minimizes the stagnation of flow at the tube-to-support interface precluding the buildup of deposits. Likewise, the tube support structure is located within the primary coolant environment; therefore, no ingress path exists for general corrosion products from the secondary system to deposit on the shell side of the SG as may occur in traditional SG designs. Outer and middle spacers welded into the pockets in the back of the tube supports (see Figure 5.4-6) allow for the tabs from each adjacent column to nest with each other to create a continuous support path through the columns. The circumferential spacing of the tube supports is optimized to provide the minimum possible tube free span lengths, while still accommodating the transition of the tubes to the steam and feedwater plena.

The SG tubes are supported for vibration and seismic loads by vertical bars that extend through the tube bundle from the feed to the steam plena. As shown on Figure 5.4-6, the tube support assemblies are attached to upper SG supports that are welded to the inner surface of the RPV and also interface with lower SG supports that are welded to the inner surface of the RPV. The SG tube support assemblies in the SG provides contact with each tube at eight separate circumferential locations. The use of 8 sets of tube support assemblies limits the unsupported tube lengths, which ensures SG tube modal frequencies are sufficiently high to preclude unacceptable flow-induced vibration.

As shown in Figure 5.4-6, the lower SG supports permit thermal growth and provide lateral support of the tube supports.

Inlet Flow Restrictors

The SG inlet flow restrictors are flow restriction devices at the inlet to each SG tube that provide the necessary secondary-side pressure drop to reduce flow oscillations to acceptable limits. The flow restrictors are mounted on a plate in each feed plenum that is attached to the secondary-side face of the tubesheets with stud bolts to avoid attaching the restrictors directly to the tube. The flow restrictor stud bolts are welded to the tubesheet at each mounting location. Mounting plate spacers hold the flow restrictor mounting plate off the surface of the tubesheet (see Figure 5.4-5). Spacers are located at each mounting plate attachment point. As shown in Figure 5.4-8, the individual flow restrictors extend into the tubes and are removable to support SG inspection, cleaning, tube plugging, or other maintenance and repair activities. The flow restrictor bolts are located at the center of the flow restrictor bolt assembly. The flow restrictor bolt runs the length of the assembly and holds the flow restrictor subcomponent. The flow restrictor bolts or nuts and the flow restrictor stud bolts or nuts include a locking feature to minimize the potential for loose parts generation.

Thermal Relief Valves

To establish desired SG and DHRS chemistry during startup and shutdown, the SG and DHRS are flushed to the condenser, creating a water solid condition. Unintended containment isolation during these flushing evolutions could result in overpressure conditions caused by changes in fluid temperature. A single thermal relief valve is located on each feedwater line upstream of the tee that supplies the feed plenums (see Figure 5.4-9) to provide overpressure protection during shutdown conditions for the secondary side of the SGs, feedwater and steam piping inside containment, and the DHRS when the secondary system is water solid and the containment is isolated. The thermal relief valves are spring-operated, balanced-bellows relief valves that vent directly into the containment. The thermal relief valves are classified Quality Group B and are designed, fabricated, constructed, tested and inspected as Class 2 in accordance with Section III of the BPVC and are Seismic Category I components. The pressure-retaining materials of thermal relief valves are specified in accordance with the materials identified in Table 6.1-3.

The thermal relief valves provide investment protection for the secondary system components during shutdown conditions and are not credited for safety-related overpressure protection for these systems during operation. Overpressure protection during operation is provided by system design pressure and the RSVs as described in Section 5.2.2.

Main Steam and Feedwater Plena Vent and Drain Valves

Manual valves allow draining the main steam and feedwater plena prior to cover removal to facilitate outage maintenance and testing. The valves are used for maintenance only and are normally closed and capped.

Compatibility of Steam Generator Tubing with Primary and Secondary Coolant

The chemistry of the primary and secondary water is controlled in accordance with industry guidelines suitably modified to address the unique NPM design and to ensure compatibility with the primary and secondary coolant. Section 5.2.3 describes the compatibility aspects of the reactor coolant chemistry that provide corrosion protection for stainless steels and nickel alloys, including SG components exposed to the reactor coolant. Section 6.1 describes the compatibility aspects of the secondary coolant chemistry that provide corrosion protection for stainless steels and nickel alloys, including the SG components exposed to the secondary system coolant and Section 10.3.5 describes the secondary water quality control program which is in accordance with Nuclear Energy Institute (NEI) 97-06 (Reference 5.4-1).

Copper deposits are a major source of SG corrosion products in nuclear plants with copper alloys in their secondary system. To minimize internal SG tube corrosion, low-melting point metals such as lead, antimony, cadmium, indium, mercury, zinc, bismuth, copper, tin, and their alloys and high sulfur materials; with the exception of strong acid cation resin; are excluded from use in reactor coolant primary system components and secondary system components.

Estimated radioactivity design limits for the secondary side of the SGs during normal operation and the basis are addressed in Section 11.1.2. The radiological effects associated with an SG tube failure are provided in Section 15.0.3.8.2.

5.4.1.3 Performance Evaluation

A single RCS natural circulation flow loop is entirely contained within the RPV, thereby eliminating distinct RCS piping loops and the associated potential for a large pipe break (i.e., large break loss-of-coolant accident [LOCA]) event. This design, combined with the intertwined SGs tube bundle configuration, eliminates the potential for asymmetric core cooling and temperatures as a result of a loss of a single SG function. Isolation or other loss-of-heat transfer capability by either of the two intertwined SGs does not introduce asymmetrical cooling in the reactor coolant vessel or system because the tube configuration of the remaining functional SG continues to provide symmetrical heat removal from the reactor coolant flowing in the downcomer of the reactor vessel.

The primary coolant system operates at a higher pressure than the secondary system resulting in the SG tubes being in compression. This configuration reduces the likelihood of a tube failure and eliminates the potential for pipe whip due to tube-side jetting.

Feedwater enters the SG tubes at their lowest point. As it rises through the tubes, it undergoes a phase change and is heated above saturation temperature before exiting the SG tubes as superheated steam. The configuration keeps the steam-water interface fluid and the superheated steam at the top of the tubes separated from the subcooled liquid at their bottoms. This configuration minimizes the hydraulic instabilities that could introduce potential sources of water hammer.

To limit the oscillation magnitude of instabilities in individual SG tubes due to fluid brought to boiling conditions as it travels up the tubes, inlet flow restrictors are added at the feedwater inlet plenum interface. Analysis shows that SG secondary side flow oscillations are decoupled from primary side flow oscillations and thus secondary side flow instabilities do not cause reactor power oscillations. In-phase oscillation of secondary flow does not occur, and the out-of-phase oscillatory flow in individual tubes cancels out, so that the net secondary flow is not oscillating. NRELAP5 analysis determines the pressure drop required for the inlet flow restrictor design to ensure that the tube mass flow fluctuations are acceptable for all power levels. Acceptable fluctuations are those that do not cause reactor power oscillations or unacceptable stresses or fatigue usage in the SG components. NRELAP5 is validated against test data for this use.

The comprehensive vibration assessment program conforms to the guidance of Regulatory Guide (RG) 1.20, Revision 3. Based on the integral design of the NPM, the SG pressure retaining components are located within the fluid volume of the RPV, along with the reactor internal components. Therefore, the SGs, main steam piping up to and including the MSIV, SG supports, and the SG tube supports are included in the comprehensive vibration assessment plan.

A set of flow-induced vibration screening criteria were developed for the comprehensive vibration assessment plan as described in Section 3.9. Under normal operating conditions, the flow energy available to excite tube vibration is low due to the low primary coolant flow rates in the NPM design.

Based on an evaluation of the screening criteria, the following lists the flow-induced vibration mechanisms and susceptible SG components that require flow-induced vibration analysis:

- fluid elastic instability: SG tubes are susceptible.
- vortex shedding: SG tubes and lower SG supports are susceptible.
- turbulent buffeting: SG tubes, SG tube supports, lower SG supports and SG inlet flow restrictors are susceptible.
- acoustic resonance: Steam nozzles, steam piping, integral steam plenum, and MSIVs are susceptible.
- leakage flow: SG inlet flow restrictors are susceptible.
- galloping and flutter: Lower SG supports are susceptible.

A fluid elastic instability analysis was performed for the tube bundle over a range of 50 vibration modes based on comparison of the effective cross-flow velocity to a critical velocity for fluid elastic instability determined using the Connor's criteria (Reference 5.4-7). The vibration modes considered in the analysis included both beam modes and lower frequency helical "breathing" modes. Fluid elastic instability testing of helical tube arrays suggests that the onset of fluid elastic instability in helical tube arrays is governed by the same parameters as for arrays of straight tubes. Connor's constants selected for the fluid elastic instability evaluation considered the results of this testing. Comparison of effective cross-flow velocities to calculated critical velocities for the NPM steam generator showed a minimum margin of 33 percent to the onset of fluid elastic instability.

Vortex shedding is precluded for downstream tubes based upon the overall turbulence created due to flow through the tube bundle disrupting the formation of coherent vortices. However, the tubes at the inlet to the tube bundle are evaluated to ensure that vortex shedding is precluded based on tube structural frequencies, damping, overall flow velocity, and a combination of these factors. The tubes at the bottom of the bundle (cold leg) are the only tubes susceptible to vortex shedding because they have no adjacent downstream obstruction to disrupt vortices.

Turbulent flow was evaluated to determine the mechanical wear of the SG tubes by turbulence in the RCS flow and tube internal axial flow. A 20.8 percent fatigue usage factor is calculated based on tube impact stress. Maximum fretting wear thickness ratio is calculated to be 34.2 percent during the 60-year design life, which is less than 40 percent allowable tube wall wear depth.

The SG tube flow restrictors are rigid components and have a high fundamental frequency, which provides for low turbulent buffeting vibration amplitudes. Due to the low vibration amplitudes, fatigue stresses are negligible and impact between the flow restrictor and the SG tube inner diameter does not occur.

The SG tube support assemblies span the full height of the helical tube bundle and are anchored at the top by the upper SG supports and at the bottom by connection to the lower SG supports. The confinement of the tube supports within the tube bundle, where the tortuous flow path creates continuous turbulence, ensures formation of stable vortices does not occur. The axial alignment of the tube supports to the prevailing flow through the bundle ensures that the angle of attack is close to 0.0 and the aspect ratio is > 2.0, thus precluding galloping and flutter.

The upper SG supports are welded to the RPV and the integral steam plenum, and excluded from analysis due to their rigidity. The lower SG supports are welded to the RPV shell below the SG tube bundle. Individual tube supports are joined to the lower SG supports. Below the tube bundle, vortex shedding from the lower SG supports is possible. Based on their form as solid bars and an aspect ratio of four, they are not subject galloping flow-induced vibration mechanisms.

Pre-operational vibration analysis testing ensures the components experience 10^6 cycles of vibration. Instrumentation used in vibration testing ensures vibration resolution of at least 500 Hz and the sampling rate encompasses the dominant frequencies of the SGS components.

Comprehensive vibration analysis demonstrates that flow-induced vibration is either not predicted to occur or the effects are shown to be acceptable for the design life of the SG pressure retaining components, including the main steam piping, MSIVs, and the SG tube support assemblies.

The SG reliability is evaluated using the reliability assurance program described in Section 17.4 and SG risk significance is determined using the guidance described in Chapter 19. The SG classification and risk categories are included in Table 3.2-1.

5.4.1.3.1 Allowable Tube Wall Thinning under Accident Conditions

Minimum wall thickness SG tubes were evaluated to combined design basis pipe break and safe shutdown earthquake loads. The analysis imposed worst-case loading conditions were upon uniformly thinned tubes at the most critical location in the steam generator. The worst-case condition assumes all thinning occurs on the tube inner diameter.

The SG tube, existing at the minimum tolerance wall thickness is reduced further by a degradation allowance (accounting for general corrosion, erosion, wear, etc.) for a total wall reduction of 0.010 inches. The reduced wall thickness provides a safety margin (sufficient wall thickness) for a maximum stress less than the allowable stress limit, as defined by the ASME Code Level D Service condition.

Alloy 690 tubing has shown little-to-no corrosion resulting from either primary or secondary-side fluid. Primary chemistry is equivalent to existing PWR SG designs and primary flow velocities are significantly lower. The secondary side chemistry is equivalent to existing PWR designs; however, the flow conditions, including boiling, represent a departure from existing PWR SG designs. Therefore, uniform thinning is assumed on the tube inner diameter. The 0.010-inch wall thinning evaluated provides a reasonable bounding condition.

5.4.1.4 Tests and Inspections

The SGs are tested and inspected to ensure conformance with the design requirements as described in Section 5.2.4. The configuration of equipment requiring inspection or repair is designed in an accessible position to minimize time and radiation exposure during refueling and maintenance outages. Workers can access SG components without being placed at risk for dose or situations where excessive plates, shields, covers, or piping must be moved or removed in order to access components.

The SG program is based on NEI 97-06 and documented in Section 5.5.4 of the technical specifications. Because the SG tube design does not contain U-bends, a volumetric examination is performed on the entire length of the SG tubing as specified in Item B16.10 of Table IWB-2500-1 (B-Q).

Preservice examinations are performed in accordance with the BPVC, Section III, Paragraph NB-5280 and Section XI, Subarticle IWB-2200 using examination methods of BPVC Section V except as modified by Section III, Paragraph NB-5111. These preservice examinations include 100 percent of the pressure boundary welds.

A volumetric, full-length preservice inspection of 100 percent of the tubing in each steam generator shall be performed. The length of the tube extends from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet welds are not part of the tube. The preservice inspection shall be performed after tube installation and shop or field primary-side hydrostatic testing and prior to initial power operation to provide a definitive baseline record against which future inservice inspections can be compared. Tubes with flaws that exceed 40 percent of the nominal tube wall thickness shall be plugged. Tubes with flaws that could potentially compromise tube integrity prior to the performance of the first inservice inspection, and tubes with indications that could affect future inspectability of the tube, shall also be plugged. The volumetric technique used for the preservice examination shall be capable of detecting the types of preservice flaws that may be present in the tubes and shall permit comparisons to the results of the inservice inspections expected to be performed to satisfy the steam generator tube inspection requirements in the plant technical specifications.

As discussed above, the operational inservice testing and inspection programs described in Section 5.2.4 and the SG program described in Section 5.4.1.6 provide testing and inspection requirements following initial plant startup.

5.4.1.5 Steam Generator Materials

Pressure boundary materials used in the SGs and associated components are selected and fabricated in accordance with the requirements of BPVC Section III and Section II as described in Section 5.2.3, and the materials used in the fabrication of the SGs are identified in Table 5.2-4.

The RCPB materials used in the SGS are classified as Quality Group A and are designed, fabricated, constructed, tested, and inspected as Class 1 in accordance with the BPVC and the applicable conditions promulgated in 10 CFR 50.55a(b). The SGS materials forming the RCPB, including weld materials, conform to fabrication, construction, and testing requirements of BPVC, Section III, Subsection NB. The materials selected for fabrication conform to the applicable material specifications provided in BPVC, Section II and meet the requirements of Section III, Article NB-2000. The SG tubes are fabricated with SB-163 Alloy 690 (UNS N06690) and all SGS materials forming the RCPB are in accordance with BPVC, Section II, and meet the requirements of Section III, Article NB-2000. Surfaces of pressure retaining parts of the SGs, including weld filler materials and bolting material, are corrosion-resistant materials, such as stainless steel or nickel-based alloy. The SGs are constructed of materials with a proven history in light water reactor environments and the SG materials associated with the RCPB are listed in Table 5.2-4.

The FW and MS piping from the CNTS to the SGs, including the thermal relief valve, is classified as Quality Group B and is designed, fabricated, constructed, tested, and inspected as Class 2 in accordance with the BPVC and the applicable conditions promulgated in 10 CFR 50.55a(d). The Steam and feed plenum access ports and associated access covers are classified as Quality Group B and are designed, fabricated, constructed, tested and inspected as Class 1 in accordance with the BPVC and the applicable conditions promulgated in 10 CFR 50.55a(b).The FW and MS piping, thermal relief valve, steam plenum access ports, and plenum access covers, including weld materials, conform to fabrication, construction, and testing requirements of BPVC, Section III, Subsection NC. The materials selected for fabrication conform to the applicable material specifications provided in BPVC, Section II and meet the requirements of Section III, Article NC-2000. The materials and applicable specifications of the MS and FW piping, associated reducers and elbows, steam plenum access ports, and plenum access covers and fasteners are provided in Table 5.4-3.

Welding of the RCPB portions of the SGS is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME BPVC, Section III, Subarticle NB-4300 and Section IX. Welding of the secondary side portions of the SGS is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME BPVC, Section III, Subarticle NC-4300 and Section IX.

The inside and outside surfaces of the integral steam and feed plenum access ports are clad with austenitic stainless steel. The cladding on the inside surfaces is deposited with at least two layers: the first layer is Type 309L and subsequent layers are Type 308L. The cladding on the outside surfaces is deposited with at least one layer of Type 309L.

The SG weld filler metals are listed in Table 5.2-4 and Table 5.4-3 and are in accordance with BPVC, Section II, Part C.

The SG supports and SG tube supports are designated as BPVC, Section III, Subsection NG "Internal Structures." The design, fabrication, construction, and testing of the SG tube supports, including weld materials, follow all requirements of BPVC, Section III, Subsection NG, with the following two exceptions. The SG tube supports are not Code stamped as "Core Supports" per NG-8000. Fabrication follows NG-4000, except that an N-Certificate holder is not required, however the fabricator is required to have a 10 CFR 50 Appendix B quality program.

The SG piping structural supports, including weld materials, conform to fabrication, construction, and testing requirements of BPVC, Section III, Subsection NF. SG piping structural support materials are provided in Table 5.4-3.

The SG inlet flow restrictors are non-structural attachments to the RPV. The SG inlet flow restrictors are designed, fabricated, constructed, tested and inspected in accordance with the ASME BPVC, Section III, Subsection NC.

Refer to Section 5.2.3 for additional description of material compatibility, fabrication and process controls, and welding controls related to the ASME Class 1 components. Refer to Section 5.2.3.4.2 for cleaning and cleanliness controls for the SGs. Refer to Section 6.6 for additional description of material compatibility, fabrication and process controls, and welding controls related to the ASME Class 2 components.

Threaded fasteners are described in Section 3.13.

5.4.1.6 Steam Generator Program

The SG program monitors the performance and condition of the SGs to ensure they are capable of performing their intended functions. The program provides monitoring and management of tube degradation and degradation precursors that permit preventative and corrective actions to be taken in a timely manner, if needed. The SG program is described in the plant technical specifications and is a part of the overall ISI program. The program implements applicable portions of Section XI of the BPVC and specifically addresses 10 CFR 50.55a(b)(2)(iii). Appendix B to 10 CFR 50 applies to implementation of the SG program.

The NuScale SG Program follows NEI 97-06 and EPRI guidance (Reference 5.4-2). Application of established commercial SG Program requirements to the NuScale design are appropriate based on the historical causes of SG tube degradation and the features of the NuScale SG design. The NuScale design incorporates design improvements necessary to restrict SG tube degradation and has additional design features that reduce the risk of SG tube degradation compared to existing PWR designs.

Historically, significant SG tube degradation has occurred in the operating PWR SG fleet due to various corrosion mechanisms, including wastage and both primary and secondary side stress corrosion cracking. These corrosion mechanisms were related to materials selection, plant chemistry control, and control of the ingress of impurities and corrosion products to the SGs. In the operating fleet, detrimental SG corrosion has been effectively mitigated based on use of A690TT SG tubing, application of EPRI primary and secondary plant chemistry control, and design of condensate systems (including extensive use of polishing resin beds and improved materials). These improvements have been implemented in the NuScale design.

In addition to chemistry and materials considerations, where the NuScale design is equivalent to the existing PWR fleet, there are two areas where the NuScale design has reduced SG tube degradation risk. The NuScale SG tube wall thickness is thicker than existing designs (see Table 5.4-2) based on incorporation of a substantial degradation allowance (additional tube wall thickness above minimum required for design) as discussed in Section 5.4.1.2. The NPM reactor coolant flowrates are lower than the flowrates across the SG tubes in PWR recirculating steam generators as discussed in Section 5.1. This low flow rate reduces the flow energy available to cause flow induced vibration (FIV) wear degradation of SG tubes. Based on the additional tube wall margin and the additional margin against FIV turbulent buffeting wear (the most likely SG tube degradation mechanism), application of the existing PWR SG Program requirements to the NuScale design is appropriate.

For SGs in the operating PWR fleet with A690TT SG tubing, the only observed degradation has been wear as a result of flow induced vibration (tube-to-tube or tube-to-support plate) or wear due to foreign objects. With respect to the risk of introduction of foreign objects, the NPM is at no greater risk than existing designs, therefore no deviations from existing SG program guidelines are warranted. From the standpoint of SG tube design, the two significant differences between the NuScale SG design and existing designs is the helical shape of the SG tubing and the SG tube support structure. The helical shape of the SG tubing itself does not represent risk of degradation based on the minimum bend radius of the helical tubing being within the experience base of operating PWR SG designs. The SG tube support design is novel. However, as discussed in Section 5.4.1.2, it preserves attributes of the existing tube support (plate) designs. Prototypic testing of the SG tube supports is performed to validate acceptable performance (including wear) of the SG tube support design. Implementation of a typical SG program is appropriate based on evaluation of the design of the SG tube supports.

5.4.1.6.1 Degradation Assessment

A SG degradation assessment of the NPM SG identified several potential degradation mechanisms. As observed in the operating PWR fleet, wear is the most likely degradation mechanism. The preliminary SG degradation assessment also identified the potential for several secondary side corrosion mechanisms, including under deposit pitting and intergranular attack based on the once through design with secondary boiling occurring inside the tubes. The estimated growth rates for these potential defects is sufficiently low that the SG tube plugging criteria for the NPM SG is a 40 percent through wall defect, consistent with the existing PWR SG fleet. Based on the ability to implement tube plugging criteria consistent with the operating PWR SG fleet, consistent implementation of other elements of the SG Program, including SG inspection frequency, is appropriate.

COL Item 5.4-1: A COL applicant that references the NuScale Power Plant design certification will develop and implement a Steam Generator Program for periodic monitoring of the degradation of steam generator components to ensure that steam generator tube integrity is maintained. The Steam Generator Program will be based on the latest revision of Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines," and applicable Electric Power Research Institute steam generator guidelines at the time of the COL application. The elements of the program will include: assessment of degradation, tube inspection requirements, tube integrity assessment, tube plugging, primary-to-secondary leakage monitoring, shell side integrity assessment, primary and secondary side water chemistry control, foreign material exclusion, loose parts management, contractor oversight, self-assessment, and reporting.

5.4.2 Reactor Coolant System Piping

5.4.2.1 Design Basis

Pressure-retaining portions of piping that penetrate the RCS form, in part, the RCPB as defined in 10 CFR 50.2 and include the pressurizer spray supply, RCS injection, RCS discharge, and RPV high-point degasification piping.

5.4.2.2 Design Description

Each of the RCS lines enter containment through welded penetrations on the containment upper head and contain two containment isolation valves mounted on the outside of the containment as described in Section 6.2.

A single pressurizer spray supply line enters through the containment head. This line branches inside containment into two pressurizer spray supply lines, each of which is welded to a penetration on the RPV upper head with a corresponding spray nozzle inside the RPV near the top of the pressurizer space.

The RPV high-point degasification line is a single line that is routed from the containment upper head to a welded penetration on the RPV upper head.

The RCS injection line is routed from the containment upper head to a welded penetration on the side of the RPV. Inside the RPV, the line continues from the RPV wall through the lower portion of the upper riser assembly and terminates near the center of the riser. Reactor coolant injection flow enters in the central riser above the reactor core. The RCS injection line also contains two branch connections to the ECCS lines that connect to the reset valves of the five ECCS valves: three RVVs and two RRVs.

The RCS discharge line is routed from the containment upper head to a penetration on the side of the RPV at an elevation just below the SGs. This penetration takes suction from the annular region between the RPV wall and the riser. Figure 6.6-1 depicts the RCS piping from the CNV upper head to the respective penetrations on the RPV.

5.4.2.3 Performance Evaluation

Section 3.9, Section 3.12, and Section 5.2 provide information regarding the RCS piping criteria, methods, and materials, and include the design, fabrication, and operational provisions to control those factors that contribute to stress-corrosion cracking. The RCS piping supports the functional aspects of the chemical volume and control system (CVCS) as summarized in Section 9.3.4.

5.4.2.4 Tests and Inspections

Preservice and ISI requirements associated with ASME Class 1 components, which include the RCS piping, are summarized in Section 5.2. Socket welds are not used on lines greater than or equal to 3/4 inch NPS and any socket weld used on piping less than 3/4 inch NPS conforms to 10 CFR 50.55a(b)(1)(ii) and ASME B16.11 (Reference 5.4-8).

5.4.2.5 Reactor Coolant System Piping Materials

Descriptions of the RCPB and materials associated with the RCS piping are provided in Section 5.2.

Refer to Section 5.2.3 and Section 5.2.4 for additional description of material compatibility, fabrication and process controls, welding controls and inspections related to the ASME Class 1 components.

5.4.3 Decay Heat Removal System

5.4.3.1 Design Basis

The DHRS provides cooling for non-LOCA design basis events when normal secondary-side cooling is unavailable or otherwise not utilized. The DHRS is designed to remove post-reactor trip residual and core decay heat from operating conditions and transition the NPM to safe shutdown conditions without reliance on external power. The DHRS is designed to cool the RCS at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded during a return to power event as described in Section 15.0.6.

The safety-related DHRS function is an engineered safety feature of the NPM design. Reliability of DHRS is evaluated using the reliability assurance program described in Section 17.4 and risk significance is determined using the guidance described in Chapter 19. The DHRS classification and risk categories are included in Table 3.2-1.

The DHRS design ensures the RCS average temperature is below 420 degrees F within 36 hours after an initiating event without challenging the RCPB or uncovering the core. An RCS average temperature of 420 degrees F was chosen based on the safe shutdown temperature proposed by EPRI for passive plant designs in the EPRI Advanced Light Water Reactor Utility Requirements Document (Reference 5.4-3) and determined to be acceptable by the Nuclear Regulatory Commission as documented in SECY-94-084.

The DHRS heat removal function does not rely on actuating ECCS. Any ECCS actuation after a DHRS actuation allows continued residual heat removal by both systems from the reactor core as described in Section 6.3.

Applicable 10 CFR 50 Appendix A, General Design Criteria and Other Design Requirements

GDC 1, 2, and 4 - The DHRS is classified Quality Group B and is designed, fabricated, constructed, tested and inspected as Class 2 in accordance with Section III of the ASME BPVC and is designed, fabricated, and tested to the highest quality standards in accordance with Quality Assurance Program described in Chapter 17. The DHRS is designed to withstand the effects of natural phenomena without loss of capability to perform its safety function. The DHRS is designed to accommodate the effects of, and be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents. The design of the Reactor Building structure, NPM operating bays, and location of the NPM within the operating bays provides protection from possible sources of external or internal generated missiles. The DHRS is protected from pipe whip as described in Section 3.6.

GDC 5 - The DHRS does not share any active or passive components between individual NPMs necessary for performance of the DHRS safety functions. The NPMs share the reactor pool as the ultimate heat sink for removal of decay heat from the DHRS passive condensers. The shared Reactor Building and other structures are described in Chapters 1 and 3 and the reactor pool is described in Section 9.2.5. DHRS active components fail-safe on a loss of power. Therefore, shared power supplies between NPMs do not impact the capability of performing the DHRS safety functions.

GDC 14 - The DHRS is connected to the secondary system and does not directly interface with the RCPB. The SGs are described in Section 5.4.1 and the containment system piping coupling the DHRS to the SGs is described in Section 6.2.4. There are no other interfaces or shared components between the DHRS and the RCPB.

PDC 19 - The DHRS is initiated from the control room and is capable of safe shutdown of the reactor. The DHRS can also be initiated from outside the MCR in the MPS equipment rooms within the reactor building.

PDC 34 (refer to Section 3.1 for the definition of PDC 34)- The DHRS is a passive design that utilizes natural circulation flow from the SGs to dissipate residual and decay core heat to the reactor pool. The DHRS consists of two independent trains each capable of performing the system safety function in the event of a single failure. The DHRS actuation valves fail open using nitrogen accumulation pressure when electrical power is interrupted to the valves. Therefore, electrical power is not required for system function. A nonsafety-related containment flood and drain system is used to flood the containment to allow cooldown to cold conditions by convection heat transfer from the RPV shell to the CNV shell to allow for disconnection and transfer of the NPM to the refueling area. During NPM transfer to the refueling area, residual and decay heat removal is provided by heat convection and conduction from the reactor to the reactor pool via the RCS, flooded containment, and the RPV and CNV walls. Refer to Section 9.2.5 for discussion related to the reactor pool for GDC 45 and 46, and PDC 44. Refer to Section 3.1 for the definition of PDC 44.

GDC 54 and 57 - The DHRS is a passive closed system outside the NPM connected directly to the steam and feedwater piping between the steam and feedwater system isolation valves and the RPV. This closed-loop DHRS outside the containment is directly connected to the closed-loop SGS within the RPV providing dual passive barriers between the RCS and the reactor pool outside the NPM. DHRS actuation valves are provided to prevent system flow within the closed DHRS loop when the system is not in operation. Breaches of this piping system outside containment is not considered credible because the system is a welded design with a system design pressure equivalent to the RPV, designed to Class 2 requirements in accordance with ASME BPVC, Section III, and meets the applicable criteria of NRC Branch Technical Position 3-4, Revision 2, as described in Section 3.6.2.5. As a result, leakage detection and isolation capabilities of this piping system from containment are not considered important to safety. Section 3.1 and Section 6.2.4 provide additional discussion regarding conformance with GDC 54. The design supports and exemption from GDC 57.

10 CFR 50.34(f)(2)(xxvi); NUREG-0737 Task Action Plan Item III.D.1.1 - The DHRS is designed with adequate leakage detection and control processes to minimize potential exposure to workers and the public, and to provide reasonable assurance that the DHRS is available to perform its intended functions. The DHRS is not connected directly to the RCS. Interface with the RCS is via the SGs, which are subjected to the design, inspection, and testing controls described in Section 5.2.4 and Section 5.4.1. The SGs are used during normal operations and leakage from the RCS into the SGs is identified and resolved consistent with requirements limiting RCS leakage and the SG program. The requirements for primary-to-secondary leakage monitoring and the SG program are established in the plant technical specifications.

10 CFR 50.62(c)(1) - DHRS actuation valves fail open on either an actuation signal from the module protection system or loss of control power to the valves. The DHRS system does not require added inventory to perform its cooling function. As discussed in Section 15.8, the NuScale design supports an exemption from 10 CFR 50.62(c)(1). Section 19.2 provides additional information on the NuScale Power Plant response to anticipated transient without scram events.

10 CFR 50.63 - Upon a loss of normal AC power with no backup power supply system available, the DHRS is designed to remove decay heat at a rate sufficient to maintain

adequate core cooling during the 72-hour station blackout coping duration. Discussion of the station blackout coping duration is provided in Section 8.4.

10 CFR 20.1406 - The DHRS is not directly connected to the RCS. Therefore, radioactive contamination in the DHRS originates indirectly from the feedwater and main steam systems. The system designs and programs that limit radioactive contamination of the facility from the feedwater and main steam systems also minimize, to the extent practicable, the generation of liquid and gaseous radioactive waste in and by the DHRS. Potential contamination by the DHRS is minimized by an all-welded design and provisions for leakage detection.

A discussion of the facility design and procedures related to minimizing the generation of radioactive waste and the minimization of contamination to the facility and environment during operation and plant decommissioning is provided in Section 12.3.6.

5.4.3.2 System Design

The DHRS is comprised of two DHRS trains associated with each individual NPM. No portions of the DHRS are shared between NPMs. Each train of DHRS is associated with one of the two NPM steam generators. The DHRS piping connects to the main steam and feedwater lines specific to the associated SG. The DHRS steam inlet piping connects with the main steam line upstream of the associated MSIV. The DHRS piping is routed to two DHRS actuation valves arranged in parallel. Each train has an orifice between the actuation valves and the DHRS passive condensers to moderate flow during operation. The piping re-joins after the actuation valves and is routed down the outside of the CNV to the train-specific DHRS passive condenser. The outlet of the DHRS passive condenser is routed to the feedwater line supplying the associated SG, joining the feedwater line downstream of the MFIV. Figure 5.4-10 provides a simplified diagram of the DHRS illustrating the operational flowpath and major system components. Table 5.4-5 provides a summary of DHRS design data.

Prior to power operations, the feedwater pumps fill the DHRS up to the actuation valves. The DHRS passive condensers and piping are maintained filled and pressurized by connection to the feedwater system on the DHRS outlet line to the feedwater piping inside containment.

During normal power operations, the DHRS is in a standby configuration with each train of DHRS isolated from the associated main steam lines by the closed DHRS actuation valves. These four valves, two each, arranged in parallel on each train, are maintained closed.

Actuation of the DHRS is accomplished automatically by the MPS and designed with capability for manual initiation from the control room or remote location outside the main control room. For physical and cyber security purposes, the MPS design does not allow remote access to operate safety related systems. Therefore, if main control room evacuation is required prior to DHRS actuation, manual actuation of DHRS may be accomplished locally at the MPS cabinets for the DHRS valves. Following actuation, DHRS operational parameters are monitored from the remote shutdown station.

Details of the design and redundancy bases of the actuation systems, including system actuation setpoints, reliability, and diversity, are provided in Chapter 7.

Upon actuation, the MSIVs and FWIVs are closed and the DHRS actuation valves open. The DHRS actuation valves are designed to open upon interruption of control power whether due to control system actuation or loss of power. Actuation permits the water column in the DHRS piping to drain into the feedwater system piping and plenum, and steam to flow from the SG into the DHRS piping and DHRS passive condenser. Steam is condensed in the passive condenser by transfer of heat to the reactor pool. This process results in a continuing flow of condensate from the passive condenser to the associated feedwater line and into the associated SG. See Figure 5.4-9 for the system layout and interface with the main steam and feedwater piping and SGs.

The DHRS function is dependent on the closure of the associated safety-related MSIVs and FWIVs. In the event an MSIV fails to close, the backup MSIV provides isolation for the DHRS loop. The feedwater regulating valve would provide isolation in the case where the FWIV failed to close. These closures isolate the SGs and associated DHRS loops from the steam and feedwater systems ensuring adequate water inventory in the passive closed loop configuration. The MSIV and MFIV functions, including their actuation, are described in Section 6.2 and Chapter 7. The SGs are described in Section 5.4.1. The steam and feedwater piping is described in Chapter 10.

The DHRS flow is driven by natural circulation resulting from the density differences between the steam and condensate portions of the DHRS and associated SG. The DHRS passive condensers are located at a higher elevation relative to the SGs to promote natural circulation flow to the SGs. The RCS temperature and pressure sensors provide indication that the DHRS is operating normally. The RCS temperature and pressure decrease following a reactor trip and DHRS actuation, provide indication that the DHRS is working normally. A representative sketch illustrating relative elevation differences is provided in Figure 1.2-7.

The DHRS function is dependent on the presence of the reactor pool to remove heat from the DHRS passive condensers. The safety-related ultimate heat sink provided by the reactor pool is described in Section 9.2.5.

The safety-related passive system is designed to cool the RCS from normal operating conditions to below 420 degrees F within 36 hours assuming one DHRS train actuates and one of two associated actuation valves functions.

The DHRS is not in direct contact with, nor does it utilize the reactor coolant other than to depend on heat transfer from the reactor core to the SGs to perform its function.

No reduction of the RCS pressure and temperature is required for actuation of the DHRS function because the DHRS utilizes the normally operating SGs as the interface with the RCS. There is no potential for interfacing system loss of coolant to occur during DHRS operations because there is no direct flow path between the RCS and DHRS. As described in Section 5.2.2, overpressure protection for the DHRS is provided by a system design that does not exceed the BPVC service limits during normal operation, or during design basis accidents and transients, thereby precluding the need for low-pressure system interlocks or pressure relieving devices on the DHRS. Under normal operating conditions and pressure transients internal pressure limits on the DHRS are not exceeded. Overpressure protection for DHRS internal pressure is provided by the RSVs in the event of a SG tube failure coincident with the RCS pressure exceeding the design pressure of the RCS.

During shutdown conditions, thermal relief valves provide overpressure protection for the DHRS when the secondary system is water solid and the containment is isolated. Refer to Section 5.4.1 for further discussion of secondary system thermal relief valves.

Upon cooling to stable shutdown conditions, cooldown to cold conditions and long term decay heat removal is provided via conduction and convection through a flooded containment and CNV shell to the reactor pool. When RCS pressure decreases below the ECCS valve inadvertent actuation block threshold pressure, the RVVs and RRVs may be opened to promote circulation between the RCS and flooded containment. Operation of the RVVs and RRVs is described in Section 6.3.

During NPM movement to and from the refueling area and during refueling, the DHRS does not provide a decay heat removal function. Residual and core decay heat removal during these shutdown conditions is provided by utilizing conduction through the RPV and containment shell with the RVVs and RRVs open or direct contact with the reactor pool water during refueling.

The DHRS actuation valves, piping, and passive condensers are classified Quality Group B and designed as Class 2 in accordance with Section III of the BPVC and remain operable following a design basis seismic event. The DHRS supports are designed and fabricated as Class 2 in accordance with BPVC, Section III, Subsection NF. Details of the classification designations and the scope of their applicability are provided in Chapter 3. It provides information regarding the design basis and qualification of structures, systems, and components based on these classifications and designations. Section 6.1 provides details regarding material selection and fabrication methods and discusses compatibility with fluids that the DHRS components may be exposed to during normal, accident, maintenance, and testing conditions. Table 6.1-1 provides a list of material and material specifications for engineered safety feature components, including the DHRS components and supports. Welding of the DHRS is conducted utilizing procedures qualified in accordance with the applicable requirements of ASME BPVC, Section III, Subarticle NC-4300 and Section IX.

The DHRS condenser, actuation valves, and DHRS piping are Seismic Category I components. The DHRS is protected from other natural phenomena by the reactor building structure. The DHRS instrumentation and control components are seismically qualified in accordance with Institute of Electrical and Electronic Engineers (IEEE) 344-2004, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," as modified by the NRC staff position stated in RG 1.100, Revision 3 (Reference 5.4-4).

A portion of the DHRS is submerged in the reactor pool and protected from internal generated missiles by the NPM operating bay walls. There are no credible sources of internally generated missiles in the area above the NPM as there is no rotating equipment in proximity to the NPM. Section 3.6.5 provides additional information on DHRS protection from pipe whip and internally generated missiles.

Potential LOCA loads do not affect the DHRS components because it is not connected to the RCS, and critical components are located outside the CNV. For discussion of stress analyses associated with the feedwater, DHRS, and steam piping inside the containment that connects the DHRS to the SGs, refer to Section 3.9.

5.4.3.2.1 Components

Actuation Valves

The actuation valves are located on top of the NPM between the steam line connection and the upper header of the DHRS condenser. Each train contains two parallel actuation valves. A single failure for one actuation valve allows normal DHRS flow to pass through the second actuation valve.

The DHRS is automatically initiated by the engineered safety features actuation system portion of the MPS. The signals that actuate DHRS are listed in Section 7.1 and requirements associated with the engineered safety features actuation system are provided in plant technical specifications. Actuation of the DHRS includes the opening of the actuation valves and the closing of the FWIVs and the MSIVs. The DHRS actuation valves are designed to fully open within 30 seconds from receipt of a DHRS actuation signal and fully close within 30 seconds from receipt of a close signal when differential pressure between the feedwater system and main steam system is 50 psid or less.

The DHRS actuation valves can be manually opened using the nonsafety module control system (MCS) if nonsafety control is enabled in the MPS. Manual actuation is not credited for design basis events.

The DHRS actuation valves open upon de-energization eliminating susceptibility to failure modes created by loss of power or by events affecting the instrumentation or actuation devices. The DHRS actuation valves are designed and qualified for torque opening using pneumatic pressure to provide sufficient mechanical force to utilize seat and actuator friction to prevent reclosing of the ball valve for the time period required to meet their design-basis and beyond-design-basis functions.

Passive Condenser

Each NPM consists of two DHRS condensers mounted to the outside surface of the CNV immersed in the reactor pool providing the heat transfer area necessary to condense steam as part of the two-phase DHRS loop.

Each condenser consists of upper and lower headers connected to a series of tubes that provide the heat transfer surface and form the pressure boundary of the heat exchanger. The inside of the headers and the tubes contain secondary system fluid and the outside of the headers and tubes is exposed to reactor pool fluid. The condenser inlet and outlet headers consist of five pipes that, collectively, constitute the upper and lower tube sheets, which are welded to the heat exchanger piping elements.

Restriction Orifice

The mass flow rate through the DHRS loop is restricted by an orifice installed in each DHRS steam line between the tee below the actuation valves and the inlet to the condenser. The DHRS thermal-hydraulic performance analysis evaluated the orifice loss coefficient for a variety of initial conditions to confirm that the size of the restriction orifice is adequate to provide consistent heat transfer.

5.4.3.2.2 Instrumentation and Controls

Level

Accumulation of noncondensible gas in the DHRS steam lines degrades DHRS system performance. Level sensors are provided to detect the accumulation of noncondensible gas in the steam lines below the actuation valves.

Each train has four level transmitters, two located on each steam pipe. Sensors are located at an elevation near the DHRS actuation valves to ensure the noncondensible gas limit is not exceeded and the associated DHRS train can perform its safety function.

A low-level alarm is provided in the control room to alert the operators if the DHRS is not filled with liquid water and, during DHRS operation, is used to confirm that the DHRS piping drains, which is characteristic of a successful actuation.

Steam Pressure

Pressure indication is provided on the DHRS steam piping section between the actuation valves and the steam line and represents main steam pressure. This pressure instrumentation provides a safety-related signal used for reactor trip and DHRS actuation and post-accident monitoring.

There are eight total steam pressure sensors per NPM, four per train. The four sensors per train are divided into two sensors per parallel DHRS steam supply line. The DHRS inlet steam pressure indication is classified as a Type D accident monitoring variable in accordance with IEEE 497-2002, "IEEE Standard Criteria for Accident Monitoring Instrumentation for Nuclear Power Generating Stations," as endorsed by RG 1.97, Revision 4 (Reference 5.4-5).

During DHRS operation, steam pressure indication is expected to yield a pressure close to the saturation pressure at the RCS temperature. Higher pressure may indicate a SG tube failure and a lower pressure may indicate a secondary side break or leak.

Actuation Valve Position

The actuation valves have position indication to provide a means for verifying that the valve position matches the demanded position. The valve position indication is classified as a Type D accident monitoring variable in accordance with IEEE 497-2002 as endorsed by RG 1.97, Revision 4.

During DHRS operation, valve position indication is used to confirm successful actuation of the system.

Condensate Temperature

Each train of the DHRS has two temperature sensors in the lower header of the condenser. Condensate temperature indication is classified as a Type D accident monitoring variable in accordance with IEEE 497-2002 as endorsed by RG 1.97, Revision 4.

During DHRS operation, condensate line temperature indication increases above the reactor pool temperature indicating that condensation and DHRS flow are actively occurring. Condensate temperature approaching the saturation temperature may be an indication of reduced water level in the DHRS condenser. Condensate temperature approaching reactor pool temperature may be an indication of a lack of DHRS circulation or an overfilled DHRS condenser.

Condensate Pressure

Each train has three pressure sensors in the lower header of the condenser. Condensate pressure indication is classified as a Type D accident monitoring variable in accordance with IEEE 497-2002 as endorsed by RG 1.97, Revision 4.

During DHRS operation, condensate line pressure indication is expected to yield a pressure close to the saturation pressure at the RCS temperature. Consistent with steam pressure, higher pressure may indicate a SG tube failure and a lower pressure may indicate a DHRS break or leak.

Nitrogen Accumulator Pressure

A nitrogen accumulator pressure element is used to verify that the accumulator pressure is at an acceptable value for the valve to perform its safety function. If the accumulator pressure is below an acceptable value, an alarm annunciates in the main control room.

Decay Heat Removal System Controls

The DHRS control system is limited to an on or off signal to the actuation valves with no ability for modulation. DHRS is actuated from the MPS and a discussion of the MPS is provided in Chapter 7.

5.4.3.3 Performance Evaluation

The DHRS provides passive, safety-related, single active failure-proof, and redundant capability to cool the reactor core and coolant to safe shutdown conditions. The DHRS heat removal function does not rely on actuating ECCS. Any ECCS actuation after a DHRS actuation allows continued residual heat removal, by both systems, from the reactor core. Both liquid and vapor water are contained in the DHRS on system actuation. Because the DHRS is a closed system, the total water mass remains constant during system operation. The bottom of the DHRS condensers on the exterior of the

NPM is located at an elevation above the bottom of the SGs which provides the static head to aid in driving the natural circulation.

Reliability of the DHRS is ensured by two independent trains of passive cooling loops. Each train is associated with a single SG preventing unavailability of one from affecting the capability of the DHRS to function. Either DHRS train may be actuated by a single-failure proof DHRS actuation valve arrangement. DHRS passive flow is established from density and elevation differences between the SGs as they add heat to the coolant and form steam, and the DHRS passive condensers which transfer heat to the reactor pool by condensing the steam to a liquid that subsequently returns to the associated SG. Table 5.4-8 provides the failure modes and effects analysis for the DHRS.

Each NPM, including the associated DHRS, are located within the Reactor Building, which protects the system from physical damage by events and phenomena external to the facility as discussed in Section 3.8.

The DHRS piping branches from the main steam lines outside and above the CNV and upstream of the MSIVs. Piping for each train is routed to the actuation valves and then to the associated passive condenser. The passive condensers are attached to the outside of the CNV with physical separation, submerged in the surrounding reactor pool. The DHRS condensate return piping from the passive condensers re-enters the CNV where it joins the main feedwater piping, downstream of the FWIVs to return condensate flow to the associated SG.

Figure 5.4-10 provides an overview of the DHRS valves, piping, and passive condenser arrangement.

The DHRS piping and passive condensers are arranged around the exterior of the CNV and separated to reduce the potential for a single condition to affect both trains. Protection from adverse interactions with other facility equipment is mitigated by submergence of the passive condensers in the reactor pool and the module bay walls located between operating NPMs as shown in Figure 1.2-9. Protection from adverse interaction with a NPM being moved to and from the refueling location is provided by the single failure-proof Reactor Building crane used to move NPMs to and from the refueling area as discussed in Section 9.1.

Refueling and maintenance operations are conducted in the refueling area as described in Section 9.1.4. The DHRS is not functional or available during refueling operations.

5.4.3.3.1 Water Hammer

Four mechanisms of condensation-induced water hammer that can occur in two-phase piping systems were evaluated to determine the impact on the DHRS:

- pressure drop
- water cannon
- counter flow

- steam pocket collapse

Low-pressure discharge is not applicable to the DHRS flowpath because the natural circulation flow rate is not high enough to cause a large pressure drop and does not pass through significant restrictions.

The other three mechanisms require subcooled liquid in the presence of steam. This condition can occur when the DHRS actuation valves change position.

The water cannon effect was evaluated during opening and closing operation of the DHRS actuation valves. If the actuation valves close while the system is in operation, steam is trapped in the DHRS piping. The liquid produced by condensation in the steam space is not significantly subcooled and the rate of condensation is not significant enough to cause water hammer because a portion of the upper DHRS steam piping is not immersed in the reactor pool water and is insulated. This section of pipe does not allow for rapid condensation necessary to cause water hammer. The water cannon effect may also be present during DHRS actuation when the actuation valves are initially opened. The low differential pressures in the DHRS prevent water cannon from causing significant pressure waves.

The counter flow mechanism in horizontal pipes is not applicable to the DHRS design because the DHRS piping has at least a slope of 3 degrees from the horizontal. This minimum slope criterion maintains vertical stratification at the liquid steam interface and prevents pockets of vapor from being collapsed by surrounding subcooled liquid.

Steam pocket collapse requires liquid fill pressure to exceed saturation pressure. The DHRS is filled by condensation; thus, the liquid fill pressure is dictated by condensation pressure and does not exceed saturation pressure.

5.4.3.3.2 System Noncondensible Gas

The DHRS, steam generators, and secondary system piping do not include safety-related high-point vent capability. During normal operation, noncondensible gases are continuously vented via the main steam system. Accumulation of noncondensible gas may occur in the DHRS steam piping between the closed actuation valves and the DHRS level switches when DHRS is not in service. A conservative mass of noncondensible gas that can accumulate in the DHRS steam piping between the level sensor location and the DHRS actuation valves is calculated and provided as an input into the DHRS performance analysis to ensure noncondensible gas accumulation does not impede the safety function of the DHRS.

To maximize the mass of noncondensible gas in the DHRS, the temperature of the noncondensible gas is assumed to be at 60 degrees F based on a minimum pool temperature of 65 degrees F. The minimum noncondensible gas temperature maximizes solubility of oxygen and nitrogen. The selected pressure of 552.3 psia is derived from the feedwater plenum pressure during normal operation at 102 percent power. Actual pressure near the DHRS actuation valves would be less by the hydrostatic pressure of the DHRS fluid.

The secondary water chemistry program limits the maximum dissolved gas concentration in the feedwater system to 50 ppb. The saturation concentration of air is 1.22E+7 ppb at 552.3 psia. Molecular or turbulent diffusion brings the DHRS piping concentration up to the concentration of the feedwater piping. There is no plausible physical process that would cause the noncondensible gases to concentrate from the feedwater piping to the DHRS piping at a higher concentration.

The DHRS is filled with degassed feedwater during startup and any postulated leaks would be from the high pressure secondary to the environment. Therefore, 10 percent of the predicted feedwater dissolved gas concentration of 1.22E+7 ppb is assumed to determine the maximum concentration of noncondensible gases allowed in the DHRS. Using 10 percent of the saturation concentration considers a failure in the feedwater system degassing equipment with margin.

The bounding mass of noncondensible gas is assumed to be 0.422 kg by calculating the volume inside the DHRS steam piping between the level sensor location and the DHRS actuation valves. Heat removal capabilities were evaluated with the bounding mass of noncondensible and found to be acceptable. Level sensor elevations are selected to limit the volume of noncondensible gas that can accumulate in the piping before being sensed. The internal volume of the piping below the DHRS actuation valves and above the DHRS level sensor is the largest volume of noncondensible gas that could be in the system when it is actuated. The DHRS level sensors ensure that the system remains within the evaluated maximum noncondensible gas accumulation for heat transfer.

5.4.3.3.3 Flow-Induced Vibration

Section 3.9 describes the comprehensive vibration assessment program for the NPM and includes an assessment the DHRS components exposed to secondary side flow.

Based on an evaluation of the program screening criteria, the applicable DHRS components are susceptible to acoustic resonance. No other flow-induced vibration mechanisms are credible for the DHRS components exposed to secondary side flow.

Analysis demonstrates that flow induced vibration is either not predicted to occur or the effects are shown to be acceptable for the design life of the DHRS components.

5.4.3.3.4 Thermal-Hydraulic Performance

As a two phase natural circulation system, DHRS performance is dependent on the following factors:

- RCS temperature - A higher RCS temperature provides a larger driving temperature difference and, therefore, increases DHRS heat transfer.
- water inventory - Water level must be sufficient to ensure the heat transfer surfaces are wetted, but low enough to ensure adequate surface area in contact with a two-phase mixture for boiling and condensation to be effective.
- noncondensible gas - Accumulation of noncondensible gas in the DHRS condenser has the potential to impede condensation heat transfer.
- reactor pool water temperature - Pool water temperature affects the mode of heat transfer on the exterior of the DHRS condenser tubes.
- pressure losses – The DHRS loop pressure losses are dominated by the restriction orifice that limits the mass flow rate and heat removal.
- driving head – The DHRS loop driving head is provided by the elevation difference between the bottom of the DHRS condenser and the bottom of the SG.

To assess the impact of these factors, a thermal-hydraulic analysis of DHRS performance has been performed with NRELAP5 to calculate the DHRS heat transfer rate. The performance analysis is divided into three model categories:

- Steady State Model - Efficient model used to characterize the effect of the listed factors on the DHRS heat removal rate.
- Nominal Transient Models - Full transient models used to show that the DHRS cools the RCS for typical initiating events and conditions.
- Off-Normal Transient Models - Full transient models used to show that the DHRS provides adequate cooling even with the most limiting initiating events and conditions.

The analytical model used for the DHRS performance analysis and the basis for its validity is provided in Section 15.

Steady State Model

To determine the capability of the DHRS, a steady state model evaluates the DHRS with a constant primary side temperature, a constant primary side flow rate, a constant reactor pool temperature, and a constant mass of DHRS inventory. With these variables held constant, the steady state DHRS heat transfer rate is calculated.

An initial core power of 102 percent is assumed to account for uncertainty in the measurement of core power thereby producing a higher decay heat and a multiplier of 1.2 is applied to the core decay heat. A loss coefficient in the DHRS steam line is calculated to ensure acceptable system performance and relatively consistent heat transfer for a range of DHRS inventories. This loss coefficient is used to determine the diameter of the restriction orifice in the DHRS steam line.

The steady state model is varied to account for additional steam volume in the piping up to the nonsafety steam isolation valve in the event of a failure of an MSIV to close. The model is also varied to evaluate the effects of DHRS and SG fouling and SG tube pugging.

The steady state model is varied to include noncondensible gas in the DHRS steam piping. Additionally, the limiting mass of dissolved gas in the DHRS liquid that could be released during DHRS operation when the water is boiled in the SG is used in the DHRS performance analysis.

Nominal Transient Model

Nominal transients are analyzed to provide DHRS cooldown capability considering two category of cases: actuation of DHRS coincident with containment isolation and actuation of DHRS without containment isolation. The main difference in these two categories is the time required for pressurizer level to drop resulting in pressurizer heater isolation because containment isolation results in isolation of the CVCS lines.

Off-Normal Transient Model

Off-normal transients determine the capability of the DHRS to remove decay heat under limiting conditions. These transients include factors such as fouling of heat transfer surfaces, plugged SG tubes, reactor pool water temperature, and the presence of noncondensible gas to assess the limiting heat transfer capability of the system. To conservatively assess the heat removal capability of the system, the containment isolation valves and DHRS actuation valve timings are biased to result in the worst-case DHRS inventory conditions.

Decay Heat Removal System Performance Analysis

The analysis evaluated the DHRS capability of removing heat over a range of DHRS loop inventories with the steady state model. Sensitivity cases indicate that the DHRS is insensitive to a wide range of reactor pool temperatures and to the failure of an MSIV to close.

The base case was adjusted to determine the effect of DHRS performance over the DHRS loop inventory range at different RCS hot temperatures. Heat removal performance over the loop inventory range was shown to be similar for different RCS temperatures and overall DHRS performance decreases with decreasing RCS temperature due to the reduced driving temperature for heat transfer.

The base case was also adjusted to determine the effect of fouling of the heat transfer surfaces, SG tube plugging, and noncondensible gas accumulation on DHRS performance over the DHRS loop inventory range. The DHRS performance analysis assumes fouling factors of 0.0005 hr-ft^2-°F/BTU for the DHRS condenser and steam piping heat transfer surfaces and 0.0001 hr-ft^2-°F/BTU for the SG heat transfer surfaces, SG tube plugging of 10 percent, and a noncondensible gas mass of 0.422 kg. The performance analysis shows that fouling of the heat transfer surfaces and SG tube plugging has a moderate effect on DHRS performance, decreasing the peak heat removal capability, and the presence of noncondensible gas has less impact on DHRS performance.

The DHRS performance decreases with decreasing RCS temperature. As RCS temperature decreases, the driving temperature difference for DHRS heat transfer is reduced. The presence of noncondensible gas in the DHRS condenser further reduces system performance as RCS temperature decreases. A lower RCS temperature corresponds to a lower DHRS pressure allowing the noncondensible gas to expand and occupy a larger fraction of the internal volume of DHRS condenser resulting in reduced performance.

The likelihood of noncondensible gas accumulating down to the level sensors in the DHRS steam piping during the operating cycle was assessed and it was concluded that reaching the noncondensible gas limit in the DHRS steam piping is unlikely. In the event noncondensible gas reaches the limit, the affected DHRS train may no longer be capable of performing its intended safety function. Plant technical specifications provide requirements for the DHRS and associated remedial actions when the minimum requirements are not met.

Upon a loss of normal AC power with no backup power supply system available, DHRS actuates followed by opening of the RVVs and RRVs when DC power is no longer available to the associated pilot valves. However, the DHRS performance analysis does not include the synergistic RCS cooling effects associated with concurrent DHRS and ECCS operation.

<u>Decay Heat Removal System Performance Results</u>

The system performance analysis indicates the DHRS is capable of removing appreciable amounts of heat over a wide range of inventories and it is insensitive to a wide range of reactor pool temperatures and to the failure of an MSIV to close. The analysis also shows the ability to accommodate fouling and SG tube plugging. In addition, performance analysis indicates that the DHRS is capable of cooling the RCS below 420 degrees F in less than 36 hours with an accumulation of noncondensible gases, thus precluding the need for high-point vent capability.

Figure 5.4-11 shows RCS cooldown for 4 hours from full power conditions with two DHRS trains in operation assuming nominal system conditions and indicates that RCS temperatures decrease below 420 degrees F in less than 2 hours. For this nominal two DHRS train case, RCS average temperature stabilizes below 300 degrees F within 36 hours.

Figure 5.4-12 through Figure 5.4-15 show the RCS cooldown response during transient cases with one DHRS train in operation assuming low and high DHRS inventories. These off-normal transient cases assume an initial reactor pool temperature of 100 degrees Fahrenheit and reduced heat removal capability due to fouling, SG tube plugging, and accumulation of noncondensible gases. Figure 5.4-12 and Figure 5.4-14 show the RCS cooldown over 4 hours and Figure 5.4-13 and Figure 5.4-15 show the RCS cooldown over 36 hours. The low DHRS inventory case indicates that RCS average temperature stabilizes below 350 degrees F within 36 hours and the limiting high DHRS inventory case indicates that RCS average temperature stabilizes below 400 degrees F within 36 hours. An additional high DHRS inventory case is run using an initial reactor pool temperature of 140 degrees Fahrenheit. This pool temperature is consistent with the upper limit temperature in Section 3.5.3 of the Technical Specifications. The results in Figure 5.4-16 show that the limiting reactor pool temperature of 140 degrees Fahrenheit has a small effect on the RCS temperature after 36 hours compared to the 100 degrees Fahrenheit initial condition. Based on these results, the DHRS design is capable of cooling the RCS to below a safe shutdown temperature of 420 degrees Fahrenheit in less than 36 hours with one DHRS train in operation assuming limiting off-normal conditions and a single active failure of the associated MSIV to close.

Figure 5.4-11 and Figure 5.4-13 show the hot and cold leg temperatures difference increase as the water level in the RPV drops to near the top of the riser. When the liquid level is near the top of the riser, the reduced flow area causes more losses and impedes RCS natural circulation that increases the temperature difference. Oscillations in natural circulation of the RCS could occur once the level drops to near the top of the riser due to vapor build up in the top of the core and lower riser. The vapor eventually is discharged into the upper riser and condenses as it rises. During these potential surges, liquid water is pushed over the top of the riser and into the downcomer. Results show that the potential oscillations do not affect the ability of the DHRS to remove heat. The DHRS has been shown to be capable of removing heat in excess of decay heat after 36 hours with the RCS at 420 degrees Fahrenheit and the pool at boiling conditions.

Refer to Chapter 15 for plant initial conditions, assumptions, and response to design basis events that result in DHRS actuation.

<u>Return to Power Event</u>

In the event of an extended DHRS cooldown (post-reactor trip), when the RCS is at low boron concentrations and the CVCS is unavailable to add boron, it may be possible for DHRS to cool the core to the point of reestablishing some level of critical neutron power, if it is assumed that the most reactive control rod is stuck out. This event is caused by increased net reactivity post-reactor trip, due to a stuck or partially withdrawn control rod, followed by the DHRS overcooling the RCS. See Section 15.0.6 for further discussion of DHRS performance during a return to power event.

5.4.3.4 Tests and Inspections

Preservice and inservice inspection requirements of Section XI are met for Class 2 components of the BPVC are applicable to the DHRS components including the steam piping, actuation valves, condensers, and condensate piping.

The DHRS actuation valves are classified as Category B valves in accordance with OM Code Subparagraph ISTC-1300(b) because seat leakage in the closed position is inconsequential for fulfillment of the required function(s). Exercising the actuation valves while at power is not practicable. Therefore, the valves are full-stroke exercised during the equivalent of cold shutdown conditions as allowed by OM Code, Subparagraph ISTC-3521(c). As described in Section 3.9.6, NuScale Mode 3 safe shutdown with reactor coolant temperatures < 200 degrees Fahrenheit is considered to be the equivalent of cold shutdown as defined in the OM Code ISTA-2000. The DHRS actuation valves that are fully cycled as part of a plant shutdown satisfy the exercising requirements provided they meet the observation requirements for testing in accordance with ASME OM Code, Paragraph ISTC-3550. In addition, loss of valve actuator power and position verification testing is performed in accordance with OM Code, Paragraphs ISTC-3560 and ISTC-3700, respectively.

The DHRS automatic actuation testing and valve actuation testing, including position verification testing, is performed in accordance with plant technical specifications.

An in-situ test of the DHRS function to remove heat from the RCS is to be performed for the first installed reactor module. This one-time test will be performed as part of the initial test program, using the MHS to bring the RCS as close to normal operating conditions as practical. Once test conditions are reached, the DHRS actuation valves are opened and containment isolation valves are closed via the MPS. The RCS bulk temperature will be observed during the duration of the test and compared to a test analysis using the code of record to verify the performance of the DHRS meets design basis requirements.

5.4.4 Reactor Coolant System High-Point Vents

5.4.4.1 Design Basis

10 CFR 52.47(a)(4) requires addressing the need for high-point vents following postulated LOCAs pursuant to 10 CFR 50.46a. 10 CFR 50.46a requires high-point vents for the RCS, reactor vessel head and other systems required to maintain adequate core cooling if the accumulation of noncondensible gases cause a loss of function of these systems. 10 CFR 52.47(a)(8) requires demonstrating compliance with technically relevant portions of the Three Mile Island (TMI) requirements set forth in certain paragraphs of 10 CFR 50.34(f), including 10 CFR 50.34(f)(2)(vi). The RCS venting capability required by 10 CFR 50.34(f)(2)(vi) is substantively similar to 10 CFR 50.46a requirements.

5.4.4.2 System Design

The NPM design comprises a reactor core, two SGs, and a pressurizer, contained within a single RPV, surrounded and contained within a steel CNV.

The ECCS includes three RVVs located on the top of the RPV that discharge to the CNV upon ECCS actuation thereby venting any noncondensible gases accumulated in the pressurizer space. The ECCS, including the design, operation, single failure capability, and protection from inadvertent actuation of the RVVs, is described in Section 6.3.

The RCS does not include separate safety-related high-point vent capability. A non safety-related high-point degasification line connected to a nozzle on the upper head of the RPV, in the integral pressurizer region, permits venting the pressurizer to the liquid radioactive waste system (LRWS) via the CVCS. The LRWS contains degasifiers to remove noncondensible gases from the high-point degasification flow via the CVCS.

The noncondensible gases collected in the degasifiers are processed in the gaseous radioactive waste system. See Figure 5.1-2 for the arrangement of the high-point degasification vent line. A description of the CVCS design is provided in Section 9.3.4 and a description of the design of the liquid and gaseous radioactive waste management systems is provided in Sections 11.2 and 11.3, respectively.

Neither the ECCS circulation nor the DHRS circulation can be impeded by local accumulation of noncondensible gases at a system high-point. The ECCS is a two-phase circulation system and gas accumulation in the RPV cannot disrupt normal flow through the RVV because it is designed for gas flow. The ECCS is designed to accommodate the effects on heat transfer. The long-term core cooling model is described in more detail in the NuScale Technical Report TR-0916-51299, Long-Term Cooling Methodology, (Reference 5.4-6).

The DHRS is internally a two-phase natural circulation system that cannot have flow disrupted by gas accumulation. It has been designed for the heat transfer limiting effects of the maximum noncondensible gas accumulation. Detailed evaluation is presented in Section 5.4.3.

The primary coolant is a single-phase natural circulation system during DHRS operation. The highpoint is the RPV head. Accumulation of noncondensible gas in the RPV head can increase the pressure of the system but cannot reduce the water level in the RPV because the liquid phase is incompressible. Accumulation of noncondensible gasses does not affect primary system circulation during DHRS operation.

During startup, the high-point degasification line is used to vent the nitrogen atmosphere and other noncondensible gases from the RPV as the RCS is heated and transitions to saturation conditions. During operation, the high-point degasification line is used as needed to remove noncondensible gases as they accumulate in the pressurizer steam space. Pressurizer venting is also used during reactor shutdown to remove noncondensible gases and accelerate hydrogen removal from the RCS.

The SGs and secondary system do not include safety-related high-point vent capability. During normal operation, noncondensible gases are continuously vented via the main steam system. Accumulation of noncondensible gas may occur in the DHRS steam line between closed actuation valves and the DHRS level switches. Maximum noncondensible gas accumulation within the secondary system was calculated and considered in the DHRS performance analysis and determined not to impede DHRS operation. Refer to Section 5.4.3 for summary of the DHRS performance analysis and calculated mass of the maximum noncondensible gas assumed to accumulate within the secondary system prior to, during, and following DHRS actuation.

5.4.4.3 Performance Evaluation

During normal operation, accumulation of noncondensible gases in the RCS and the pressurizer steam space in the RPV is minimized by the removal of noncondensible gases by the LRWS degasifiers using the high-point degasification line, as needed, via the CVCS. Additionally, there are no mechanisms for accumulation of noncondensible gases in the RPV during ECCS operation because the open RVVs provide a vent path directly from the RCS to the containment; thus additional high-point venting is not required to maintain adequate core cooling and long-term cooling following a LOCA. Long-term cooling is not adversely impacted by noncondensible gases.

The NPM design does not require separate safety-related high-point venting in the RCS because noncondensible gases are vented by the ECCS reactor vent valves during and following a LOCA. Thus, during ECCS operation, the RVVs preclude the accumulation of noncondensible gases in the pressurizer space above the RCS and the ability of the ECCS to maintain adequate core cooling during accident conditions is not impeded.

Safety-related high-point venting is not required in the secondary side of the SGs or the DHRS because maximum noncondensible gas assumed to accumulate within the secondary system is calculated and included in the DHRS performance analysis and determined not to impede DHRS operation.

Refer to Section 5.4.3 for further discussion related to noncondensible gas assumption in the DHRS performance analysis.

These reasons obviate the need for high-point vents, and the NuScale design supports an exemption from the requirements of 50.34(f)(2)(vi), as well as the substantively equivalent requirements of 10 CFR 50.46a.

The RPV high-point degasification vent design does not perform a specific safety function. The high-point degasification vent isolation valves are remotely operated from the control room as described in Section 9.3.4.

5.4.4.4 Tests and Inspections

The ECCS valves form part of the RCPB during normal operations. They are tested and inspected as a part of that boundary, as well as to ensure their functional capability as safety-related ECCS components. See Section 3.9.6 and 6.3.4 for a discussion of ECCS valve testing and inspection.

The high-point degasification vent path forms part of the RCPB up to the isolation valves and is tested and inspected as a part of that boundary. See Section 5.2.4 for a discussion of RCPB testing and inspection.

5.4.5 Pressurizer

The pressurizer is an integral part of the reactor vessel and is comprised of the upper region of the reactor vessel, above the region of naturally circulating reactor coolant. A baffle plate separates the two regions. The baffle plate provides a low-resistance flow path between the pressurizer and the RCS to rapidly communicate changes in pressure between the two regions. The pressurizer region is shown in Figure 5.4-17.

The principle function of the pressurizer is to provide a surge volume of saturated water and steam that regulates RCS pressure by maintaining a saturated steam-water interface during heatup, startup, normal, transient, and faulted operating conditions. Instruments permit pressurizer pressure and the steam-water interface level in the pressurizer to be monitored for expected and postulated operating conditions.

Pressurizer pressure is controlled by the use of pressurizer heaters to increase pressure or use of pressurizer spray flow to decrease pressure. A minimal spray flow is continuously maintained during normal operation to minimize stresses from thermal transients for the spray line components.

Pressurizer instrumentation provides pressure and level information to the MPS, MCS, and control room as described in Chapter 7.

5.4.5.1 Design Basis

The pressurizer is designed to maintain RCS operating pressure so that operating transients do not result in a reactor trip or actuation of other safety systems when normal support systems are functional. It also has sufficient combined saturated water volume and steam expansion volume to provide the desired pressure response to expected system volume changes without actuating safety systems.

The pressurizer is sized to accommodate the surge resulting from operating transients without causing a reactor trip on RCS low or high pressure. It is also sized to provide sufficient steam volume to accept in-surge from a loss of load transient without liquid or two-phase flow reaching the RSVs.

The pressurizer volume is sized, in conjunction with the pressurizer level control band and the capabilities of the CVCS, to prevent uncovering of the pressurizer heaters following a reactor trip. To protect the pressurizer heater elements and the integrity of the RCPB for transients where pressurizer water level decreases below the normal operating range, power is removed to the heaters prior to pressurizer level reaching the top of the pressurizer heaters.

Compliance with the BPVC is described in Section 5.2. Equipment classification, including seismic qualification is described in Section 3.2. Section 3.9 describes loading conditions including design stress limits, and design transients.

The pressurizer location at the top of the integral RCS inside the reactor vessel allows a single location for venting of noncondensible gases. During normal operating evolutions such as startup and shutdown, a RPV high-point degasification vent line is provided to route gases from the nitrogen supply system to the RPV and from the RPV to the LRWS. Refer to Section 5.4.4 for a description of RCS high-point venting capabilities.

5.4.5.2 System Design

Table 5.4-6 provides a summary of pressurizer design data.

<u>Physical Description</u>

The RCS pressure is managed by an integral pressurizer that is the portion of the reactor vessel volume above the baffle plate inside the RPV. The pressurizer region is comprised of the volume within the reactor vessel head and a portion of the cylindrical height of the reactor vessel below the head. A baffle plate defines the lower boundary of the pressurizer volume.

The baffle plate limits heat transfer between the pressurizer region and the RCS coolant flowing from the reactor core to the SGs. The baffle plate provides flow paths that allow for flow between the hot RCS region and the pressurizer fluid to equalize pressure resulting from changes in RCS temperature. The PZR baffle plate contains eight 4-inch diameter holes which provide a low loss flow path between the PZR and the remainder of the RCS. Changes in pressure between the PZR and the remainder of the RCS are rapidly communicated.

The baffle plate also serves as the tubesheet for the upper termination of SG tube bundles into the integral steam plenums. In addition, the baffle plate provides penetrations for alignment and support of the control rod drive shafts and for alignment and support of incore instrument guide tubes. The baffle plate also contains features that support the upper riser assembly.

The total pressurizer volume is approximately 23 percent of the total RCS volume. Pressurizer level during full-power operation is controlled between 50 percent and 60 percent with a minimum pressurizer level of 50 percent at hot zero power (HZP) conditions. These programmed values provide margin to the upper and lower pressurizer water level analytical limits of 80 percent and 35 percent.

The PZR provides a saturated steam-water interface at an elevated temperature such that the reactor coolant remains subcooled during normal operation. Pressurizer performance analysis has demonstrated that RCS pressure remains less than the RSV set point for the most limiting operating transient. In the event that the RSV setpoint is exceeded, the RSVs vent from the steam region of the pressurizer and exhaust directly to the containment volume. The degasification vent line provides a path from the pressurizer for removal of noncondensible gases. During low temperature conditions, overpressure protection is provided by the RVVs which provide a relief path from the pressurizer to the containment volume.

Two sets of electrical heaters are installed in the lower portion of the pressurizer space. The heaters are installed horizontally and directly immersed in the pressurizer liquid. Pressurizer heater parameters are provided in Table 5.4-7.

Instrumentation

Pressurizer instrumentation measures the steam-water interface level and provides input to the safety-related MPS as described in Chapter 7, including the low water level protection of the pressurizer heaters. Additionally, pressurizer level instrumentation is provided to the control room to the operating staff and the MCS described in Chapter 7. As described in Table 1.9-5, the NuScale design supports an exemption from the power supply requirements for pressurizer level indication included in 10 CFR 50.34(f)(2)(xx).

Pressurizer pressure is measured and provides input to the safety-related MPS as described in Chapter 7. It also is indicated in the control room to the operating staff to indicate RCS pressure and the MCS described in Chapter 7.

Instrumentation to indicate the spray flow into the pressurizer by the CVCS, and pressurizer heaters output are also provided to the MCS. The MCS provides automated assistance to control level and pressure in the RCS.

Functional Design

Heaters are required to heat the pressurizer fluid in order to maintain the pressurizer at an elevated temperature and saturated condition. Under steady state conditions, the heater output makes up for continual losses such as heat losses to the containment and the RCS. In transient conditions involving increases in RCS volume, fluid from the hot region of the RCS enters the pressurizer and is heated to saturated liquid conditions in order to maintain normal operating pressure conditions. Similarly, for transients that involve decreases in RCS volume, the pressurizer liquid flows into the RCS hot leg and the pressurizer heaters produce additional steam to maintain normal operating pressure.

During operation, RCS pressure is controlled spraying subcooled water into the steam filled region of the pressurizer to reduce pressure, and electrical heaters submerged in the liquid portion of the pressurizer that are energized to increase pressure. The water in the pressurizer region is heated by the pressurizer heaters to a temperature greater than the coolant temperature leaving the reactor core in order to maintain a saturated water-steam interface in the pressurizer region.

Control rod drive shafts and instrument lines occupy the central region of the pressurizer. Two spray nozzles located on opposing sides of the pressurizer are provided to ensure adequate contact between the pressurizer spray and the steam.

The CVCS provides a small continuous flow to the pressurizer through the spray nozzles to maintain pressurizer region chemistry consistent with the balance of the RCS and to minimize stresses from thermal transients when full spray flow is initiated. Instrumentation is included in the CVCS portion of the pressurizer spray line to indicate in the control room the condition of spray bypass flow.

Two pressurizer heater bundles with a nominal heating capacity of 400 kW per bundle, are mounted through the side of the RPV located 180 degrees from each other around the integral steam plenum assembly as shown in Figure 5.4-4. The three-phase, 480 V heaters maintain RCS pressure during normal operating conditions with the capability to supply at least 785 kW, which includes a heater capacity margin of 15 percent. Pressurizer heaters in each bundle are divided into three control groups. Group 1 heaters are controlled by a proportional integral controller and are used to maintain nominal programmed RCS operating pressure when the reactor is operating at steady state power. The sizing includes a design consideration to maintain primary pressure considering the steady state heat losses such as continuous pressurizer spray flow, and heat transfer to the containment and the RCS. Group 2 and 3 backup heaters are energized sequentially when RCS pressure drops below the nominal programmed pressure range and are de-energized sequentially as pressure returns to the nominal operating range.

The RCS flow in the NPM is driven by natural circulation during normal operation and hot shutdown conditions. Natural circulation flow is based on maximizing the vertical elevation difference between the thermal centers of the reactor core and the SGs and minimizing the flow dependent loss coefficient of the RCS flow circuit. As a result, pressurizer heater operation is not required to establish and maintain natural circulation in hot shutdown conditions, and the NuScale design supports an exemption from the pressurizer power supply and control power interface requirements of 10 CFR 50.34(f)(2)(xiii). In addition, the NuScale design does not include pressurizer relief valves or pressurizer block valves, and the power supply requirements for these valves included in 10 CFR 50.34(f)(2)(xx) are not technically relevant.

Non-Class 1E electrical power is supplied to each of the two proportional heaters (A and B) from the low voltage AC electrical power system through two Class 1E circuit breakers that are part of the MPS and connected in series to the pressurizer control cabinet. The pressurizer heaters are controlled from the MCS via the pressurizer control cabinets. The safety-related function of pressurizer heater circuit breakers is not to ensure an electrical power supply to the pressurizer heaters. Rather, the safety-related function of these circuit breakers is to isolate the heaters from their power source to ensure the integrity of the RCPB if the heaters were to be uncovered. The MPS provides a trip function on lowering pressurizer level that removes power to the heaters prior to pressurizer level reaching the top of the pressurizer heaters. Additional detail regarding the Class 1E breakers associated with the pressurizer heaters is provided in Section 7.1.

The baffle plate is a safety-related internal structure of the reactor vessel that provides for hydraulic communication between the pressurizer and RCS regions allowing the pressurizer to perform its pressure control function. Specifically, the baffle plate is designed to:

- rapidly communicate RCS hydraulic responses to load changes to the pressurizer volume
- provide thermal and chemical mixing of fluid entering the pressurizer

5.4.5.3 Performance Evaluation

Level Control

Pressurizer level is controlled by the CVCS. During normal reactor operation, the CVCS is responsible for maintaining the correct volume of coolant in the RCS as indicated by the pressurizer liquid level instrumentation. The pressurizer level is maintained in its operating band by operator permissive action or manual operator action to add coolant inventory (makeup) or reduce coolant inventory (letdown) by discharging fluid to the LRWS.

The nominal pressurizer water level is provided as a function of reactor power level. Between HZP and 15 percent power, the reactor coolant experiences a heatup or cooldown and therefore a large change in volume. The change in volume can be partially absorbed by changing the pressurizer water level; however, to maintain a sufficient steam volume for pressure control and margin to operating limits, makeup or letdown using the CVCS is needed to compensate for the large change in temperature by removing or adding reactor coolant mass from or to the RCS. Above 15 percent power, the changes in reactor coolant volume are much smaller. The nominal pressurizer water level is set to accommodate the expected changes in RCS volume and makeup and letdown are not expected to be required to maintain pressurizer water level when maneuvering above 15 percent power.

Pressure Control

Pressurizer (and RCS) pressure is regulated by operation of PZR heaters to add steam to the PZR steam bubble and PZR spray flow to condense steam from the PZR steam bubble. The RCS supports automatic control of PZR pressure by providing the PZR control cabinet, PZR heaters and electrical cabling to facilitate powering the heaters, PZR spray nozzles and PZR spray supply piping that is connected to the CVCS, and by providing PZR pressure measurement to the MPS and MCS.

During startup, power operations, and shutdown when a steam bubble is present in the PZR, a differential temperature is present across the PZR baffle plate and RPV shell near the PZR. During heatup and cooldown events, a maximum subcooling limit is maintained to prevent excessive temperature differences across the pressurizer baffle plate.

Startup Operations

The RCS is pressurized to a low pressure with nitrogen from the CVCS. Water is added to the RCS via the CVCS to raise PZR water level to the normal operating level band. Nitrogen is vented from the PZR as necessary. Pressurizer level is regulated by the CVCS.

Pressurizer heaters are energized to raise the temperature in the PZR and draw a steam bubble. Pressurizer heater output is adjusted as needed to support pressurization commensurate with the RCS heat up rate to ensure RCS temperature and pressure remains within the specified limits.

During heatup, the module heatup system increases the RCS temperature to the HZP temperature. During the temperature increase, the pressurizer increases the RCS pressure in order to provide subcooling at the module heatup system heater exit and to reach normal operating pressure, 1850 psia.

The pressurizer heaters are used throughout heatup to add energy to the RCS. The CVCS is used to maintain pressurizer level and adjust RCS chemistry and boron concentration.

Normal Operations

During normal operations pressurizer level is controlled over a range from 50 percent to 60 percent of the overall pressurizer level. The programmed pressurizer level increases as power is increased. The RCS pressure is increased by increasing power to the PZR heaters, which generates steam that is added to the PZR steam bubble and raises pressure. The CVCS includes a PZR spray line with a control valve that provides flow to the PZR spray nozzles. A minimal spray flow is maintained during normal operation at power to maintain the PZR chemistry in equilibrium with the RCS and minimize thermal stresses to the spray line components. The PZR spray flow is at a lower temperature relative to the temperature of the saturated steam bubble. The RCS pressure is decreased by initiating spray flow through the PZR spray nozzles into the PZR steam volume. Spray flow condenses steam, reducing pressure.

Effective mixing of fluid within the PZR volume occurs during normal operation due to thermal effects associated with cooling from the PZR walls and heating from the PZR heaters. Fluid that enters the RCS from the PZR is effectively mixed with the rest of the reactor coolant as it flows down over the SG helical tube bundles, down the remainder of the downcomer, and into the reactor core. As a result, the reactor coolant entering the reactor core has a uniform temperature and boron concentration.

Shutdown Operations

Pressurizer heaters are de-energized and spray is used as needed to reduce RCS pressure. The SG steaming continues cooldown in conjunction with the pressurizer pressure reduction, to reduce the temperature of the RCS. When the RCS is sufficiently cool and pressure is sufficiently reduced the PZR steam bubble may be replaced with a nitrogen bubble. Nitrogen is introduced to the pressurizer via the high-point degasification line. Pressurizer spray is performed, and PZR heater power is reduced and then secured as the steam bubble collapses and is replaced by a nitrogen bubble.

5.4.5.4 Tests and Inspections

The RCPB portions of the pressurizer are tested and inspected as a part of the RPV testing and inspections. All regions of the pressurizer region are constructed to permit required inspections. See Section 5.2 for a discussion of RPV testing and inspections.

The pressurizer baffle plate is subject to the BPVC and the ANSI/ASME NQA-1 program. The plate support structure and attachments are inspected as a reactor vessel internal structure in accordance with the requirements of BPVC requirements.

Pressurizer heaters are monitored and tested in accordance with applicable BPVC requirements as a part of the RCPB. Testing is performed to verify their functionality in accordance with vendor recommended acceptance criteria. Each finished heater bundle is tested to verify the power rating is within 2 percent of the nominal rated power.

5.4.5.5 Pressurizer Materials

The pressurizer includes the top portion of the RPV upper shell, the RPV upper head, the pressurizer baffle plate, heater bundles, and spray nozzles. The material of the RPV upper shell and upper head is described in Section 5.2. The pressurizer spray nozzles and pressurizer spray nozzle safe ends are described in Section 4.5 and Section 5.2, respectively.

The pressurizer baffle plate is an integral part of one of the RPV upper shell forgings and is thus constructed of a Grade 3, Class 2, low alloy steel in accordance with material specification SA-508 of BPVC, Section II. The upper and lower surfaces of the baffle plate are weld clad with two layers of stainless steel for corrosion protection in accordance with material specification SFA-5.9 of BPVC, Section II; the first layer being Alloy Type ER309L and the second layer being Alloy Type ER308L. Additionally, the upper surface of the baffle plate in the regions of the SG integral steam plenums is clad with nickel-based Alloy 52/152 for compatibility.

The specific materials for the heater bundle assemblies are austenitic stainless steel or Ni-Cr-Fe Alloy. Materials for the cover plate, bolting, and heater sheaths are corrosion resistant materials that are compatible with their respective operating environments. Materials for the cover plate include austenitic stainless steel Type 304, Grade F304 and nickel-based Alloy 690 (UNS N06690). These materials comply with BPVC, Section II, Specifications SA-182 and SB-168, respectively. Materials for the heater sheaths include austenitic stainless steel Type 304L and Type 316. These materials comply with BPVC, Section II, Specification SA-213. The bolting material is nickel-based Alloy 750 (UNS N07718) and complies with BPVC, Section II, Specification SB-637.

5.4.6 References

5.4-1 Nuclear Energy Institute, "Steam Generator Program Guidelines," NEI 97-06, Rev. 3, Washington, DC, January 2011.

5.4-2 Electric Power Research Institute, "Steam Generator Management Program: Pressurized Water Reactor Steam Generator Examination Guidelines," EPRI #1013706, Rev. 7, Palo Alto, CA, 2007.

5.4-3 Electric Power Research Institute, "Advanced Nuclear Technology: Advanced Light Water Reactors Utility Requirements Document," Rev. 4, Palo Alto, CA.

5.4-4 Institute of Electrical and Electronics Engineers, "Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," IEEE 344-2004, Piscataway, NJ.

5.4-5 Institute of Electrical and Electronics Engineers, "Standard Criteria for Accident Monitoring Instrumentation for Nuclear Power Generating Stations," IEEE Standard 497-2002, Piscataway, NJ.

5.4-6 NuScale Power, LLC, "Long Term Core Cooling Methodology," TR-0916-51299, Rev. 1.

5.4-7 Chen, S.S., J.A. Jendrzejczyk, and M.W. Wambsganss, "Tube Vibration in a Half-Scale Sector Model of a Helical Tube Steam Generator," Journal of Sound and Vibration (1983): 91:4:539-569.

5.4-8 American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, "Forged Fittings, Socket-Welding and Threaded," ASME B16.11-2009, New York, NY.

Table 5.4-1: Steam Generator Full-Load Thermal-Hydraulic Operating Conditions (Best Estimate)

Parameter	Value
(1)Total heat transfer (MW_t)	159.13
SG outlet pressure (psia)	500.1
SG outlet temperature (°F)	584.4
SG inlet temperature (°F)	299.7
SG flow (lbm/hr)	532298

(1) Based on operation of both SGs, each SG is capable of providing half of the total heat transfer required.

Table 5.4-2: Steam Generator Design Data

Parameter	Value
Type	Helical, once-through
Total number of helical tubes per NPM	1380
Number of helical tube columns per NPM	21
Internal pressure - secondary (psia)	2100
External pressure - primary (psia)	2100
External pressure - SG piping in containment (psia)	1000
Internal temperature - secondary (°F)	650
External temperature - primary (°F)	650
External temperature - SG piping in containment (°F)	550
Tube wall outer diameter (inches)	0.625
Tube wall thickness (inches)	0.050
Steam tubesheet thickness, without clad (inches)	4.0
Feed tubesheet thickness, without clad (inches)	6.0
Steam and feed tubesheet clad thickness - secondary (inches)	0.250
Steam and feed tubesheet clad thickness - primary (inches)	0.375
Steam tubesheet thickness, with clad (inches)	4.625
Feed tubesheet thickness, with clad (inches)	6.625
Total heat transfer area (ft^2)	17928
Fouling factor (hr-ft^2-°F/BTU)	0.0001
Minimum SG tube transition bend radius (inches)	≥ 6.250

Table 5.4-3: Steam Generator Piping, Piping Supports, and Flow Restrictor Materials

Component	Specification	Alloy Designation[1] (Grade, Class, or Type)
SG Class 2 piping	SA-312	Type 304/304L
SG piping reducers and elbows	SA-182	Grade F304/F304L
SG piping supports	SA-479	Type 304/304L
SG tubes	See Section 5.4.1.5	
Flow restrictors and flow restrictor bolts	SA-479	Type 304
Flow restrictor mounting plates	SA-240	Type 304
Flow restrictor mounting plate spacer	SB-166	Alloy 690 (UNS N06690)
Flow restrictor stud bolts, nuts, and washers Integral steam and feed plenum port cover threaded fasteners	SB-637	Alloy 718 (UNS N07718)
Integral steam and feed plenum access ports	SA-508	Grade 3, Class 2
Integral steam and feed plenum access port covers	SA-240	Type 304/304L
Low alloy steel weld filler material	SFA 5.5 SFA 5.23 SFA-5.28 SFA-5.29	Weld filler metal classifications compatible with low alloy steel base metal
Stainless steel weld filler material (includes filler material for cladding)	SFA 5.4 SFA 5.9 SFA-5.22	E308, E308L, E309, E309L, E316, E316L ER308, ER308L, ER309, ER309L ER316, ER316L, EQ308L, EQ309L E308, E308L, E309, E309L, E316, E316L
Nickel-based alloy weld filler material	SFA-5.11 SFA-5.14	ENiCrFe-7 ERNiCrFe-7, ERNiCrFe-7A, EQNiCrFe-7, EQNiCrFe-7A

Notes:
1 - When the material is designated as Type or Grade 304/304L, this refers to dual certified stainless steel material.

Table 5.4-4: Not Used

Table 5.4-5: Decay Heat Removal System Design Data

Parameter	Value
Internal pressure (psia)	2100
Actuation valve external pressure (psia)	16.7
Passive condenser external pressure (psia)	27
Temperature (°F)	650
Number of condensers	2
Total number of tubes per condenser	80
Tube wall outer diameter (inches)	1.315
Tube wall thickness (inches)	0.109
Tube external surface area per condenser (ft^2)	258.2
Fouling factor (hr-ft^2-F/BTU)	0.0005

Table 5.4-6: Pressurizer Design Data

Parameter	Value
Internal pressure (psia)	2100
External pressure (psia)	1000
Temperature (°F)	650
Pressurizer heater sheath temperature (°F)	800
Spray nozzles	2
Nominal spray nozzle diameter (in.)	1

Table 5.4-7: Pressurizer Heater Parameters

Parameter	Value
Voltage (Vac)	480
Frequency (Hz)	60
Heater bundles per pressurizer	2
Heater groups per bundle (kW)	3
Nominal total capacity per heater bundle (kW)	400

Table 5.4-8: Failure Modes and Effects Analysis - Decay Heat Removal System

Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System	Method of Failure Detection
DHRS actuation valve DHR-HOV-0101A DHR-HOV-0101B DHR-HOV-0201A DHR-HOV-0201B (normally closed, fail open)	1) Maintain DHRS in standby	A) Spurious opening	Mechanical Electrical/I&C	Affected DHRS condenser has open flow path to SG. Turbine must be isolated to prevent damage. Normal cooling is available through feedwater. Unaffected DHRS train remains available.	• Valve position indication • Steam pressure • Steam temperature • Passive condenser temperature
		B) Spurious DHRS actuation	Electrical/I&C Operator error	Both DHRS trains initiate operation and the MSIVs and FWIVs will close. The engineered safety features actuation system will generate a reactor trip signal regardless of if the DHRS actuation signal was erroneous or not.	• Pressurizer pressure • Steam pressure • Valve position indication • Pressurizer level • Passive condenser temperature • Passive condenser level • Reactor trip
		C) Leakage (passive failure)	Mechanical	Minor leakage will not impact DHRS operation. DHRS inventory is maintained by the continuous makeup of feedwater to the steam generator. Major valve seat leakage will cause both DHRS trains to actuate.	• Minor seat leakage: - none • Major seat leakage: - Passive condenser temperature - Steam pressure - Steam temperature • Minor valve bonnet leakage: - periodic inspections • Major valve bonnet leakage: - passive condenser temperature

Table 5.4-8: Failure Modes and Effects Analysis - Decay Heat Removal System (Continued)

Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System	Method of Failure Detection
	2) Initiate DHRS cooling	A) Fail to open	Mechanical Electrical/I&C	Sufficient flow required for cooling of affected DHRS train is maintained by redundant DHRS actuation valve. Other train operates normally.	• Valve position indication
		B) Partial opening	Mechanical		
		C) Slow opening (extended stroke time or delayed actuation)	Mechanical Electrical/I&C		
		D) Spurious closure	Electrical/I&C Operator error		
		E) Leakage (passive failure)	Mechanical	Leakage out of the system results in a reduction in cooling inventory for the affected DHRS train. DHRS operation is maintained by the unaffected train. Major system leakage is addressed under DHRS Loop Pressure Boundary failures.	• Minor valve bonnet leakage: - periodic inspection • Major valve bonnet leakage: - Steam pressure (valve bonnet failure) - Passive condenser temperature - RCS temperatures
		F) Flow blockage (passive failure)	Mechanical	Reduced or nonexistent flow through affected valve but adequate DHRS flow is maintained by redundant actuation valve. The other train operates normally,	None

Table 5.4-8: Failure Modes and Effects Analysis - Decay Heat Removal System (Continued)

Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System	Method of Failure Detection
Main steam isolation valve MS-HOV-0101 MS-HOV-0201 (normally open, fail closed)	1) Isolate main steam line to establish closed DHRS cooling loop	A) Fail to close	Mechanical Electrical/I&C	DHRS inventory in the train associated with the failed MSIV will be maintained by the downstream secondary MSIV.	• Valve position indication • Steam pressure • Passive condenser temperature • RCS temperatures
		B) Partial closure	Mechanical		
		C) Slow closure (extended stroke time or delayed actuation)	Mechanical Electrical/I&C	The affected train functions normally. Secondary MSIV closure mitigates loss of inventory. System can function properly with a range of initial inventories so a loss of cooling capability in the affected train is not credible.	• Valve position indication • Steam pressure • Passive condenser temperature
		D) Spurious opening	Electrical/I&C Operator error	DHRS inventory in the train associated with failed MSIV will be maintained by the downstream secondary MSIV.	• Valve position indication • Steam pressure • Passive condenser temperature • RCS temperatures
		E) Leakage through seat or seal (passive failure)	Mechanical	The affected train functions normally. Secondary MSIV closure mitigates loss of inventory. System can function properly with a range of initial inventories so a loss of cooling capability in the affected train is not credible.	• Periodic testing & inspection • Steam pressure • Passive condenser temperature • RCS temperatures
Main steam isolation valve Bypass Valve MS-HOV-0103 MS-HOV-0203 (normally closed, fail closed)	1) Maintain DHRS pressure boundary during DHRS operation	A) Spurious opening during DHRS operation	Operator error	DHRS inventory in the train associated with failed MSIV bypass valve will be maintained by the downstream secondary MSIV.	• Valve position indication • Steam pressure • Passive condenser temperature • RCS temperatures
		B) Leakage through seat or seal (passive failure)	Mechanical	See MSIV failure mode 1E.	

Table 5.4-8: Failure Modes and Effects Analysis - Decay Heat Removal System (Continued)

Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System	Method of Failure Detection
Feedwater isolation valve FW-HOV-0137 FW-HOV-0237 (normally open, fail closed)	1) Isolate feedwater line to establish closed DHRS cooling loop	A) Fail to close	Mechanical Electrical/I&C	Additional DHRS inventory may be added to the train associated with the failed FWIV until feedwater stops flowing into the SG. The FWRV closes simultaneously, providing redundant isolation. The system can function properly with a range of initial inventories so a loss of cooling capability due to overfill is not credible.	• Valve position indication • Passive condenser temperature • Steam pressure
		B) Partial closure	Mechanical		
		C) Slow closure (extended stroke time or delayed actuation)	Mechanical Electrical/I&C	In the affected train, more DHRS inventory than anticipated may be added while the FWIV and FWRV close but the system can function properly with a range of initial inventories so a loss of cooling capability is not credible.	• Valve position indication • Passive condenser temperature • Steam pressure
		D) Spurious opening	Electrical/I&C Operator error	DHRS inventory in the train associated with failed FWIV will be maintained by the feedwater check valves upstream of the FWIV and the closed FWRV.	• Valve position indication • Steam pressure
		E) Leakage through seat or seal (passive failure)	Mechanical	The affected train functions normally. Feedwater regulating valve closure mitigates loss of inventory. System can function properly with a range of initial inventories so a loss of cooling capability in the affected train is not credible.	• Periodic testing & inspection • Steam pressure • Passive condenser temperature • RCS temperatures
Safety-related feedwater check valve FW-CKV-0136 FW-CKV-0236	1) Prevent backflow through FWIVs	A) Fail to close	Mechanical	The nonsafety-related check valve upstream of the safety-related check valve is credited to close during a FWLB. Thus, sufficient inventory is available for the affected train.	• Passive condenser temperature • Steam pressure • RCS temperatures
		B) Partial closure			
		C) Slow closure			

Table 5.4-8: Failure Modes and Effects Analysis - Decay Heat Removal System (Continued)

Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System	Method of Failure Detection
SGS Thermal Relief Valve SG-RV-0102 SG-RV-0202	1) Provide pressure boundary	A) Spurious opening of relief valve with failure to close (passive failure)	Mechanical	A spurious opening of the thermal relief valve with a failure to close will cause the affected DHRS train to lose inventory and become inoperable. Safe shutdown without emergency core cooling system (ECCS) actuation is achieved with the remaining DHRS train.	• Steam pressure • DHRS level instrument switches • Containment leakage monitoring instrumentation (containment evacuation system)
	2) Provide overpressure protection when SGS is water solid.	A) Failure of valve to lift at setpoint	Mechanical	A failure of the valve to lift during a water solid over pressure scenario could cause deformation or rupture of pressure boundary components. A rupture would cause the affected DHRS train to be inoperable. The module is in safe shutdown prior to this event and cooling will resume with the unaffected DHRS train or through flooding the CNV with the containment flooding and drain system.	• Steam pressure • DHRS level instrument switches
DHRS Loop Pressure Boundary (Includes piping inside CNV, steam generator tubes)(1)	1) Provide a pressure boundary for the SGS and DHRS	A) Pipe rupture and loss of DHRS loop inventory (passive failure)	Mechanical	A pipe rupture of any pressure boundary piping which is part of the DHRS loop (SGS and DHRS piping within containment isolation valves) will cause the affected DHRS train to lose inventory and become inoperable. Safe shutdown without ECCS actuation is achieved with the remaining DHRS train.	• Steam pressure • DHRS level instrument switches • Containment leakage monitoring instrumentation (containment evacuation system)

Notes:

(1) Pipe ruptures outside of the CNV are not postulated as the DHRS piping is specified to meet additional stress criteria specified in Branch Technical Position 3-4. Containment leakage monitoring instrumentation only identifies pressure boundary failures within the containment vessel.

Figure 5.4-1: Steam Generator Helical Tube Bundle

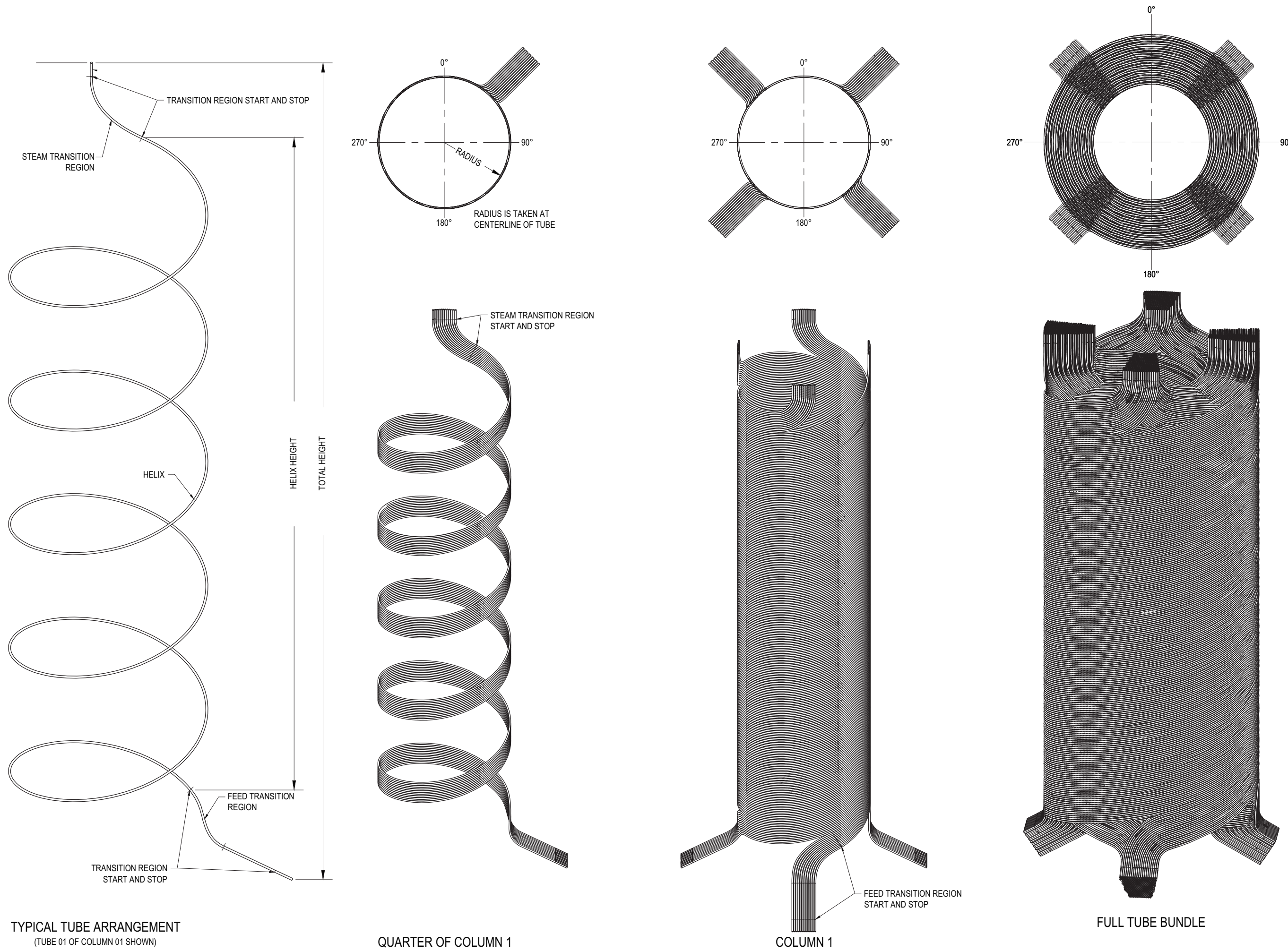


Figure 5.4-2: Configuration of Steam Generators in Upper Reactor Pressure Vessel Section

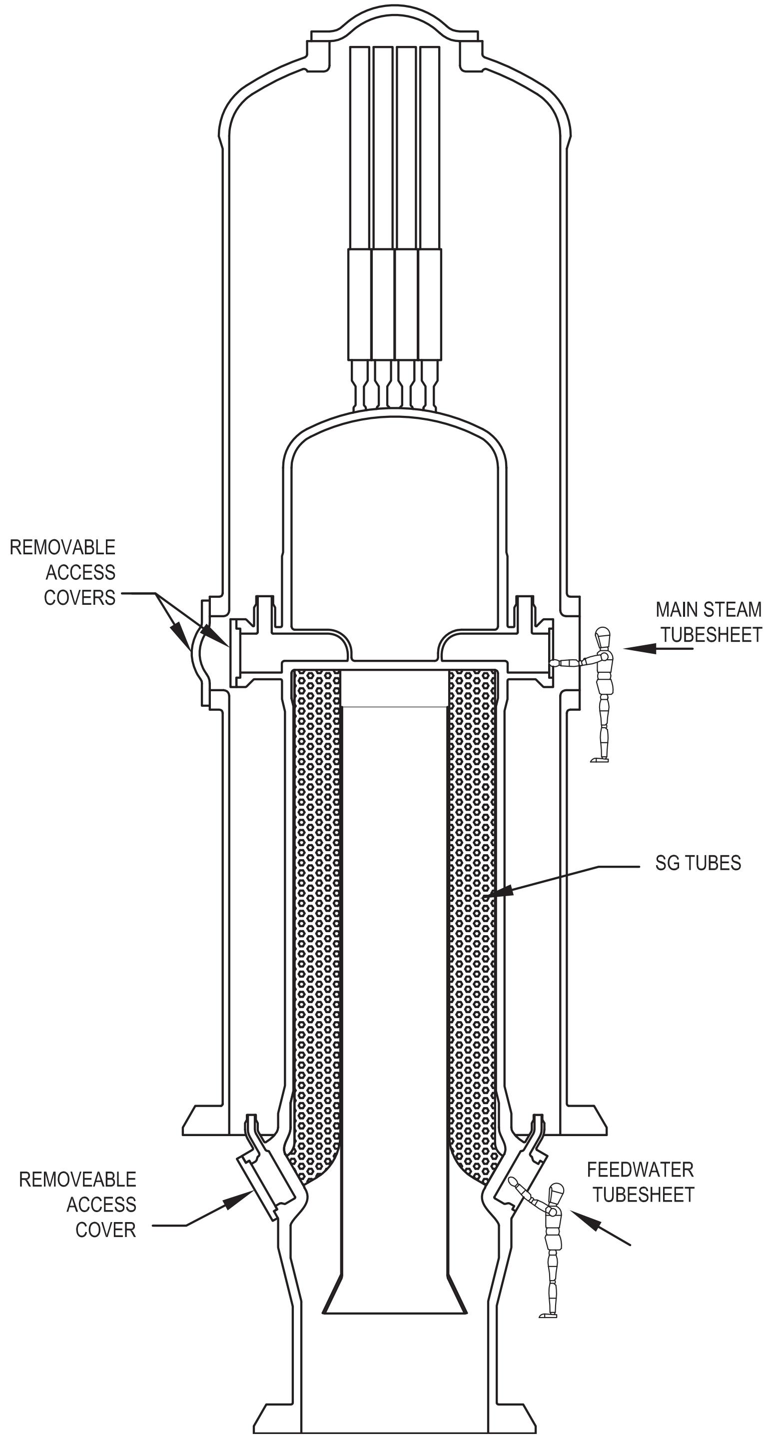
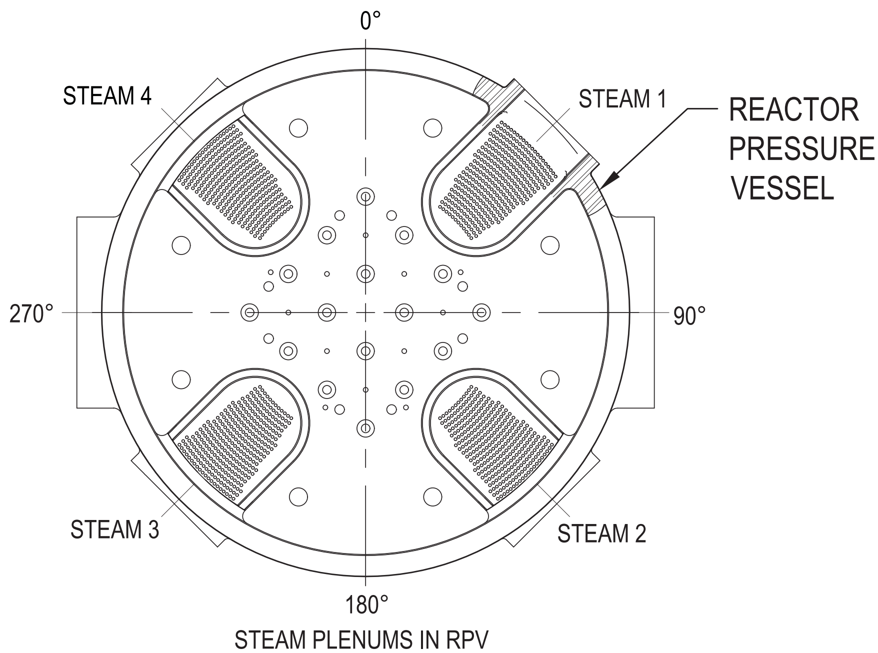


Figure 5.4-3: Main Steam and Feedwater Plena



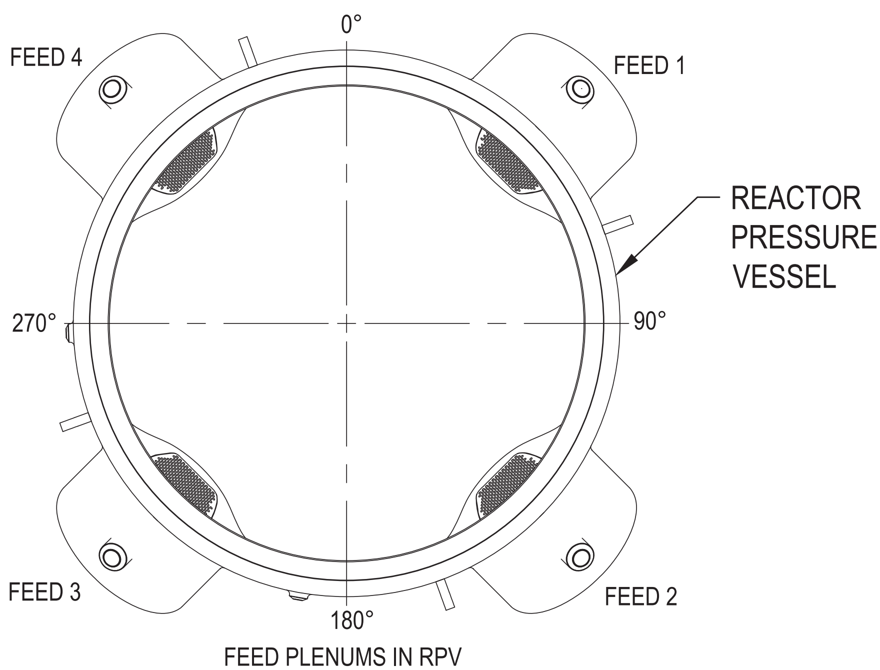
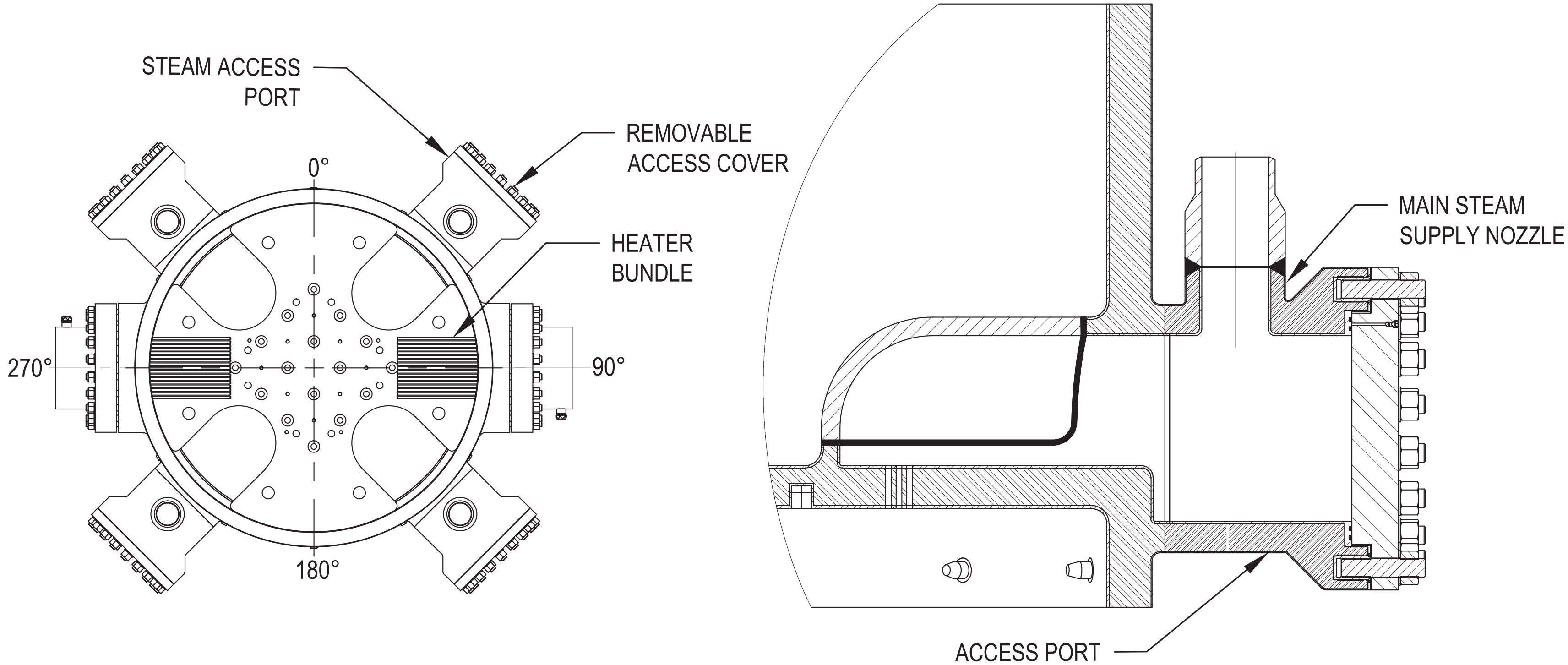


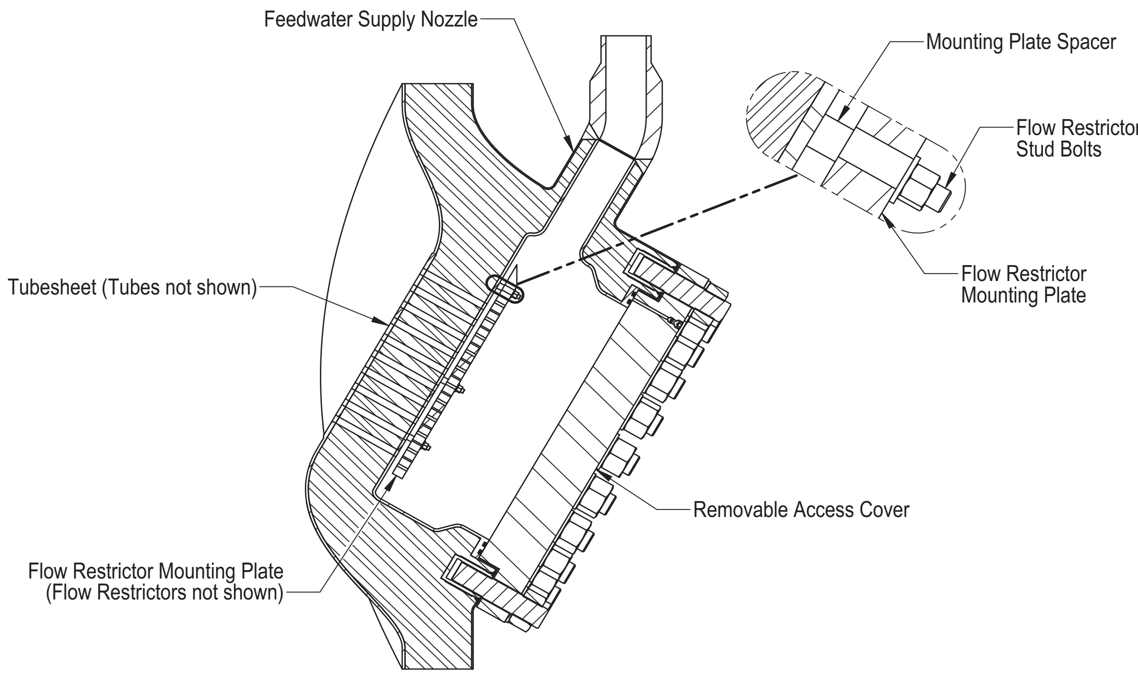
Figure 5.4-4: Integral Steam Plenum



INTEGRAL STEAM PLENUM ASSEMBLY TOP VIEW
(OVERHEAD VIEW)

INTEGRAL STEAM PLENUM
(SIDE VIEW - CUTAWAY)

Figure 5.4-5: Feedwater Plenum Access Port



FEED PLENUM ACCESS PORT CUTAWAY

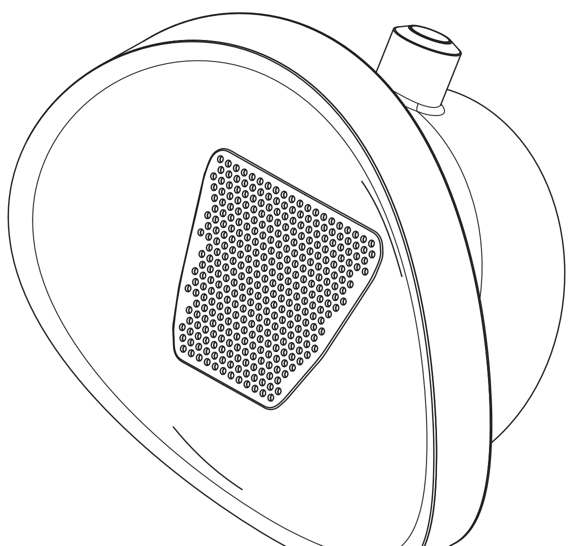


Figure 5.4-6: Steam Generator Tube Supports and Steam Generator Supports

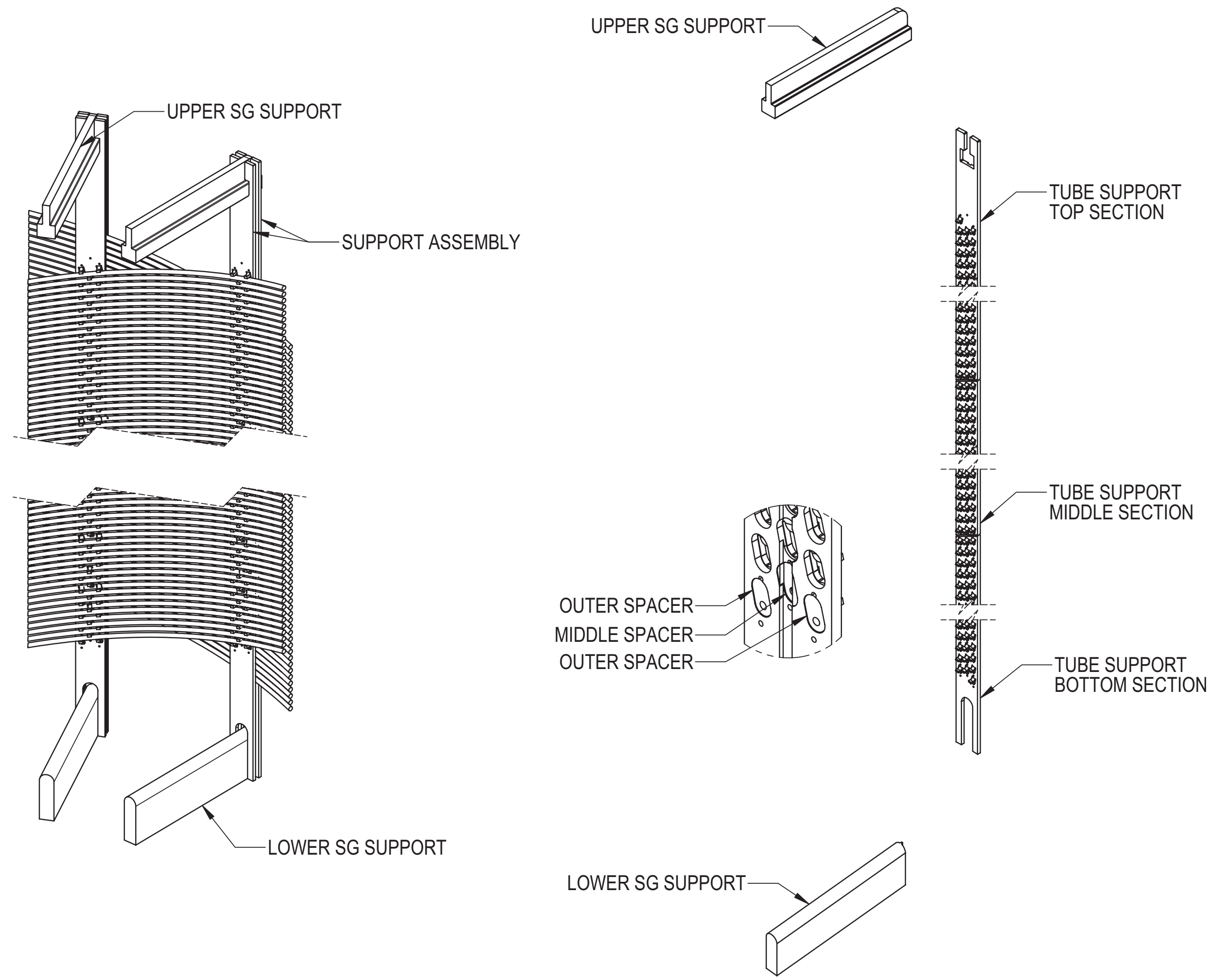


Figure 5.4-7: Steam Generator Tube Support Tabs

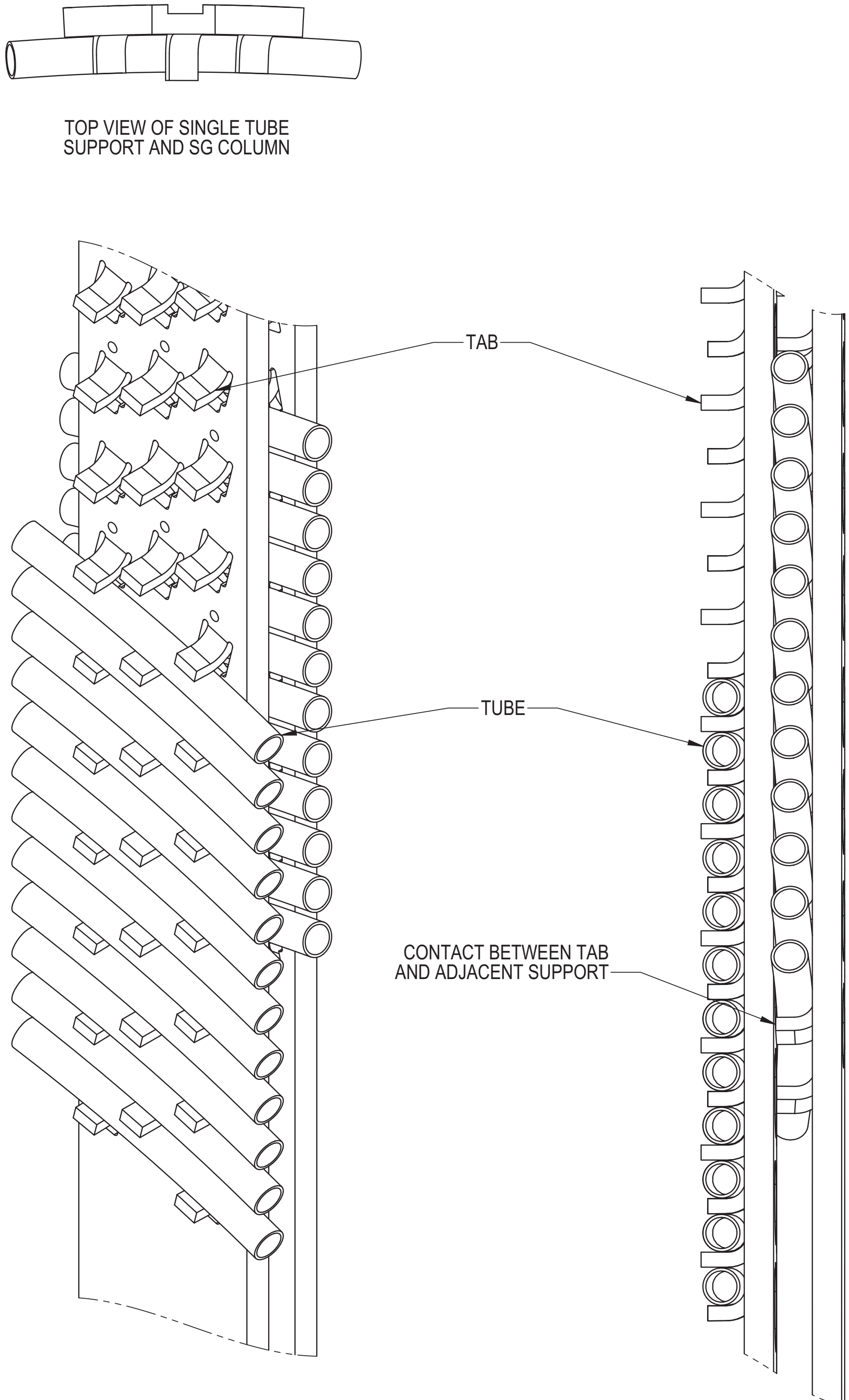
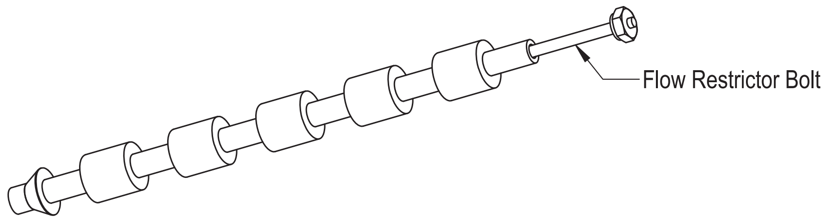
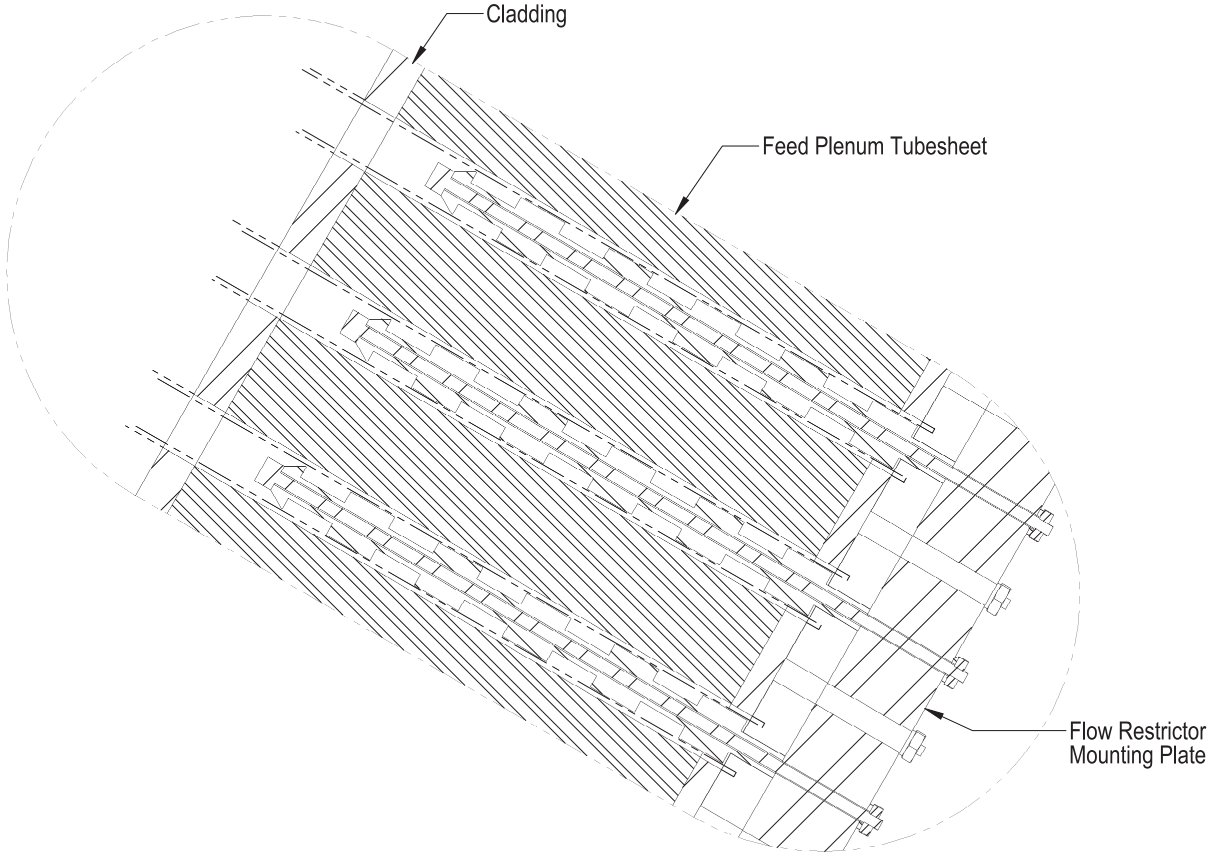


Figure 5.4-8: Steam Generator Flow Restrictor Assembly



Flow Restrictor



Flow Restrictor Mounting

Figure 5.4-9: Steam Generator Simplified Diagram

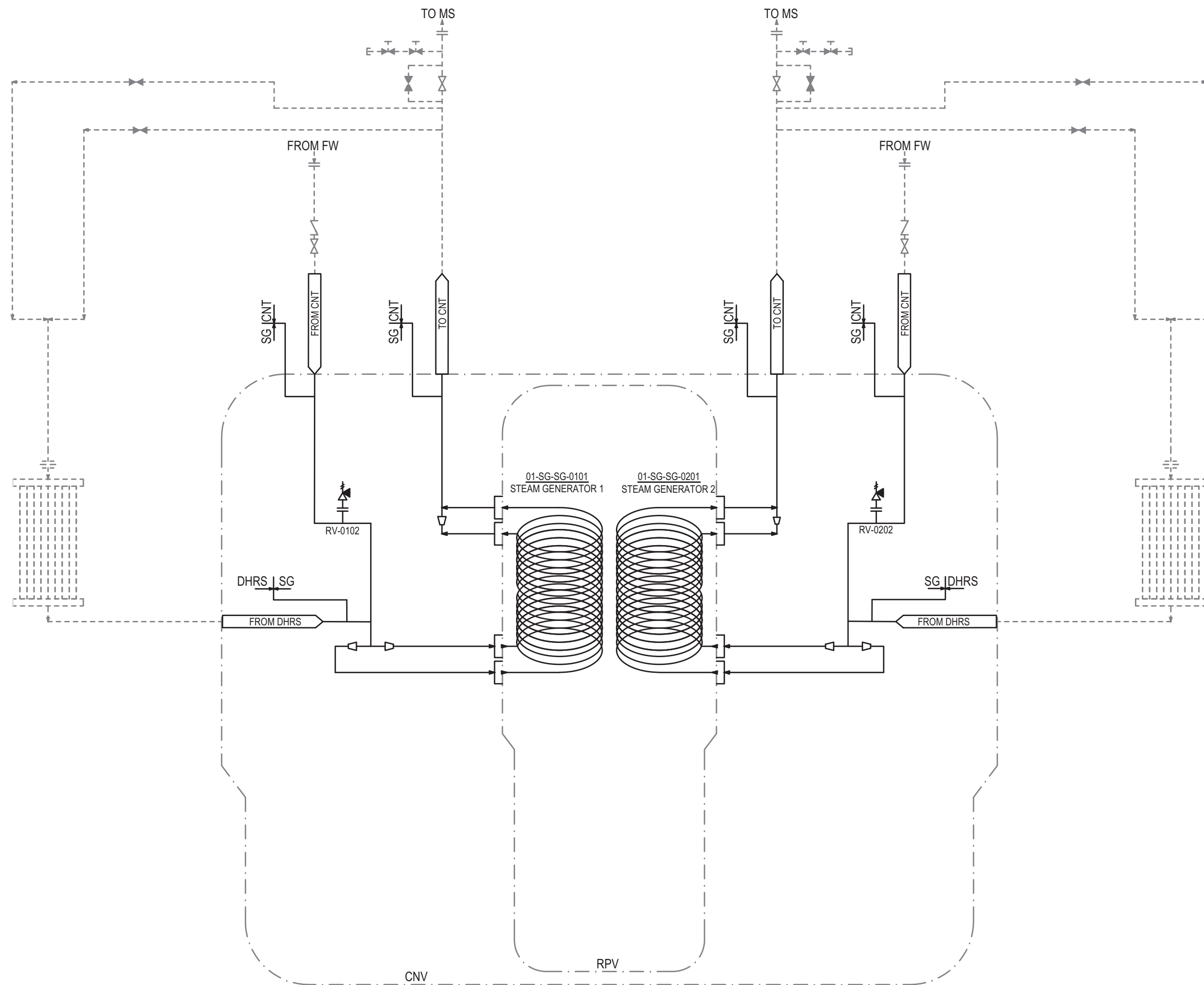


Figure 5.4-10: Decay Heat Removal System Simplified Diagram

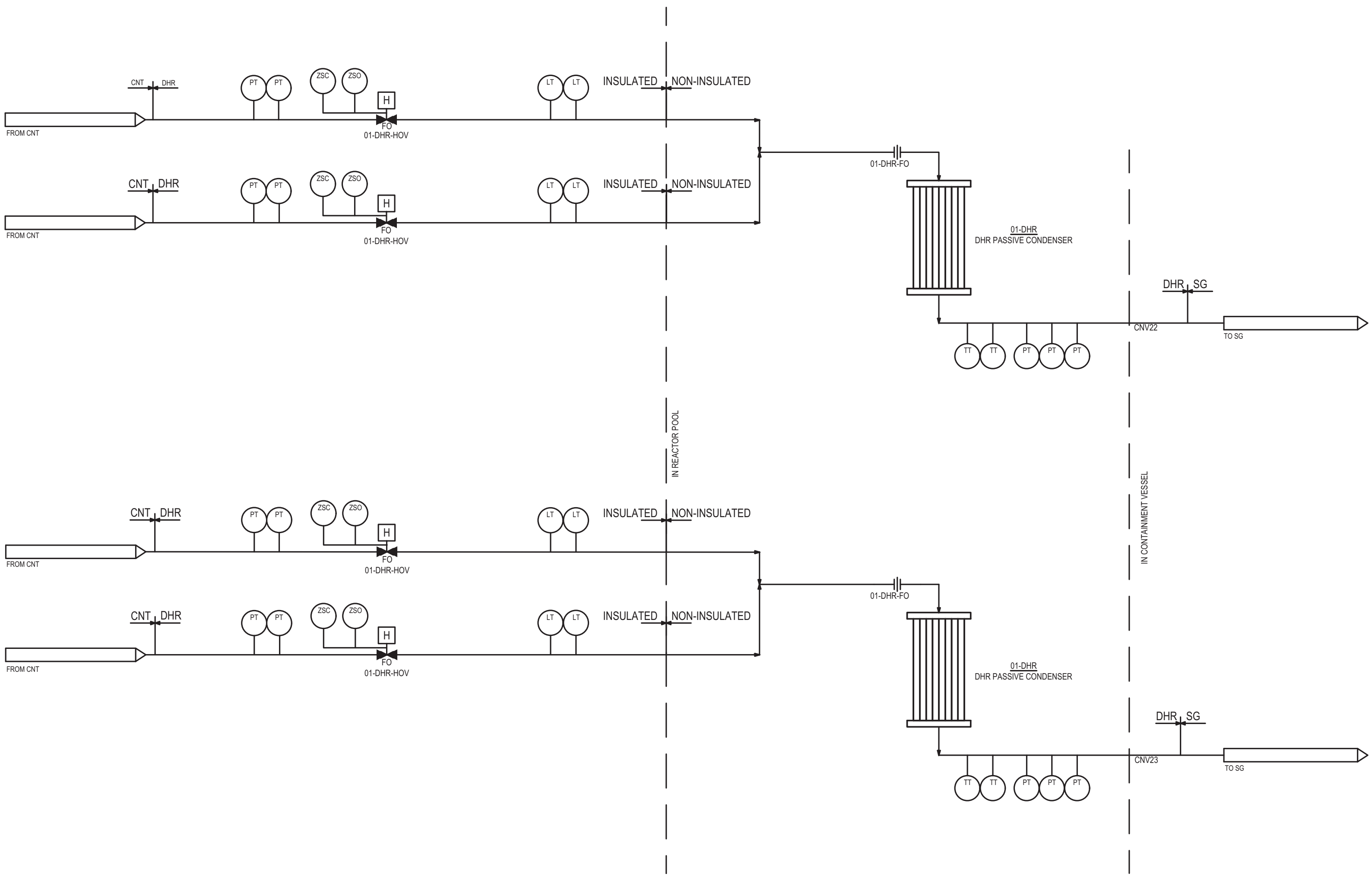


Figure 5.4-11: Primary Coolant Temperature with Decay Heat Removal System Two Train Operation - 4 Hours

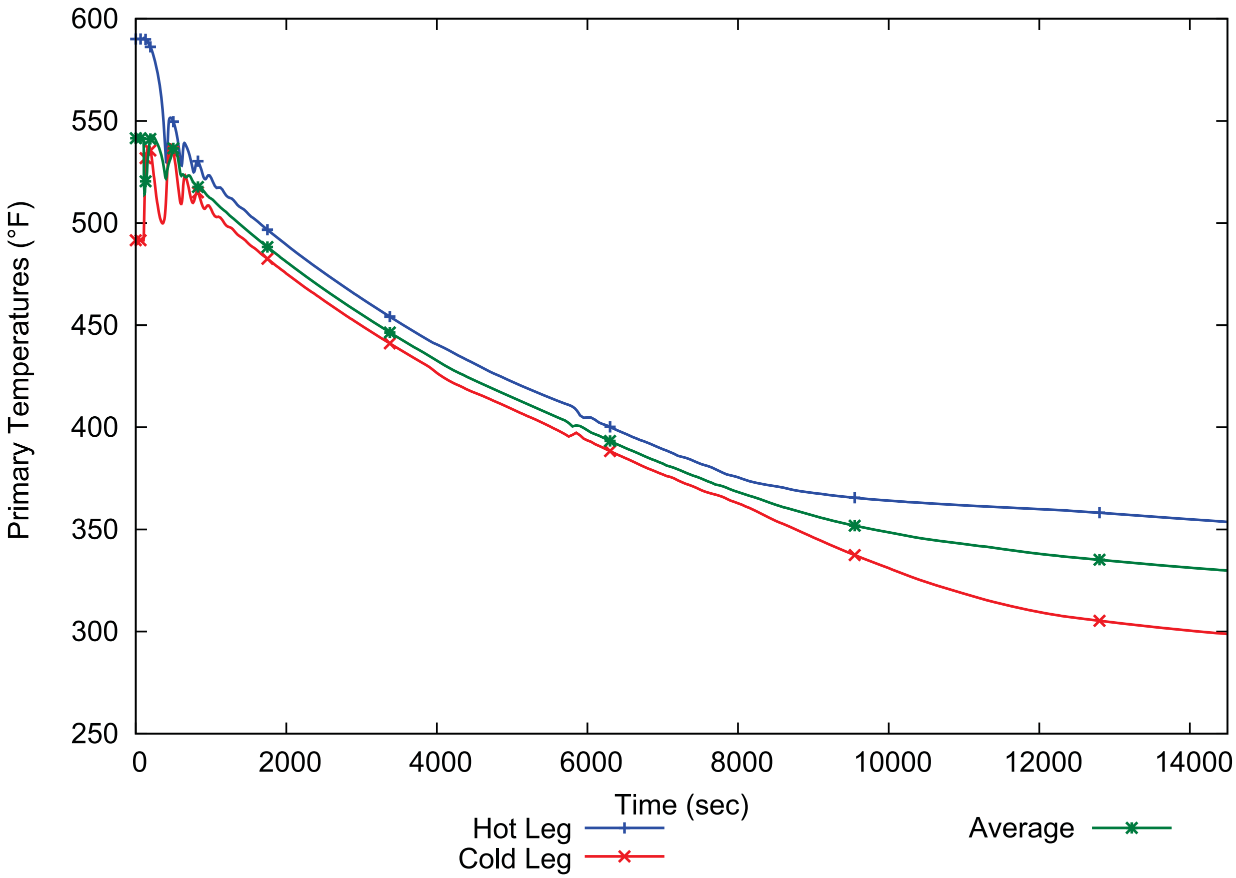


Figure 5.4-12: Primary Coolant Temperature Cooldown with Decay Heat Removal System One Train Operation: Low System Inventory - 4 Hours

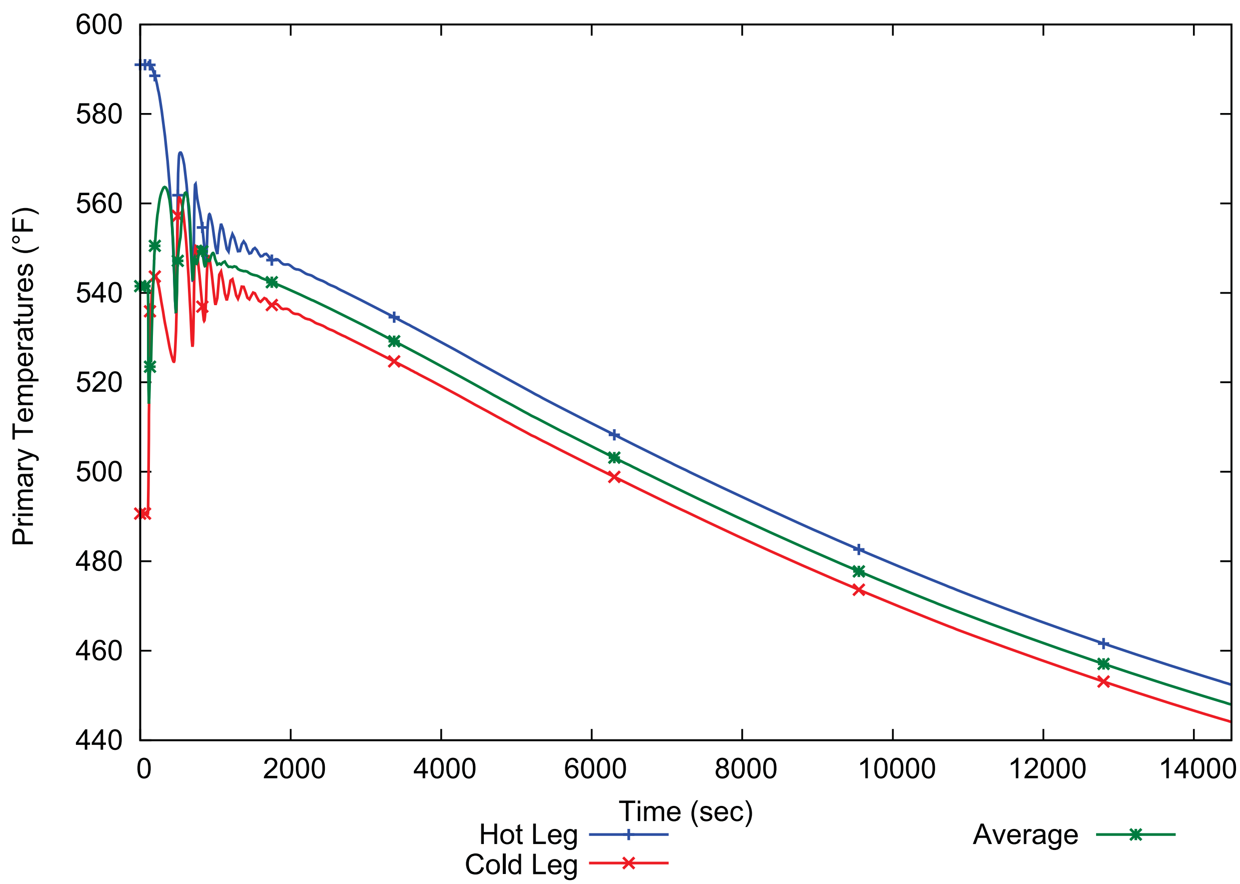


Figure 5.4-13: Primary Coolant Temperature Cooldown with Decay Heat Removal System One Train Operation: Low System Inventory - 36 Hours

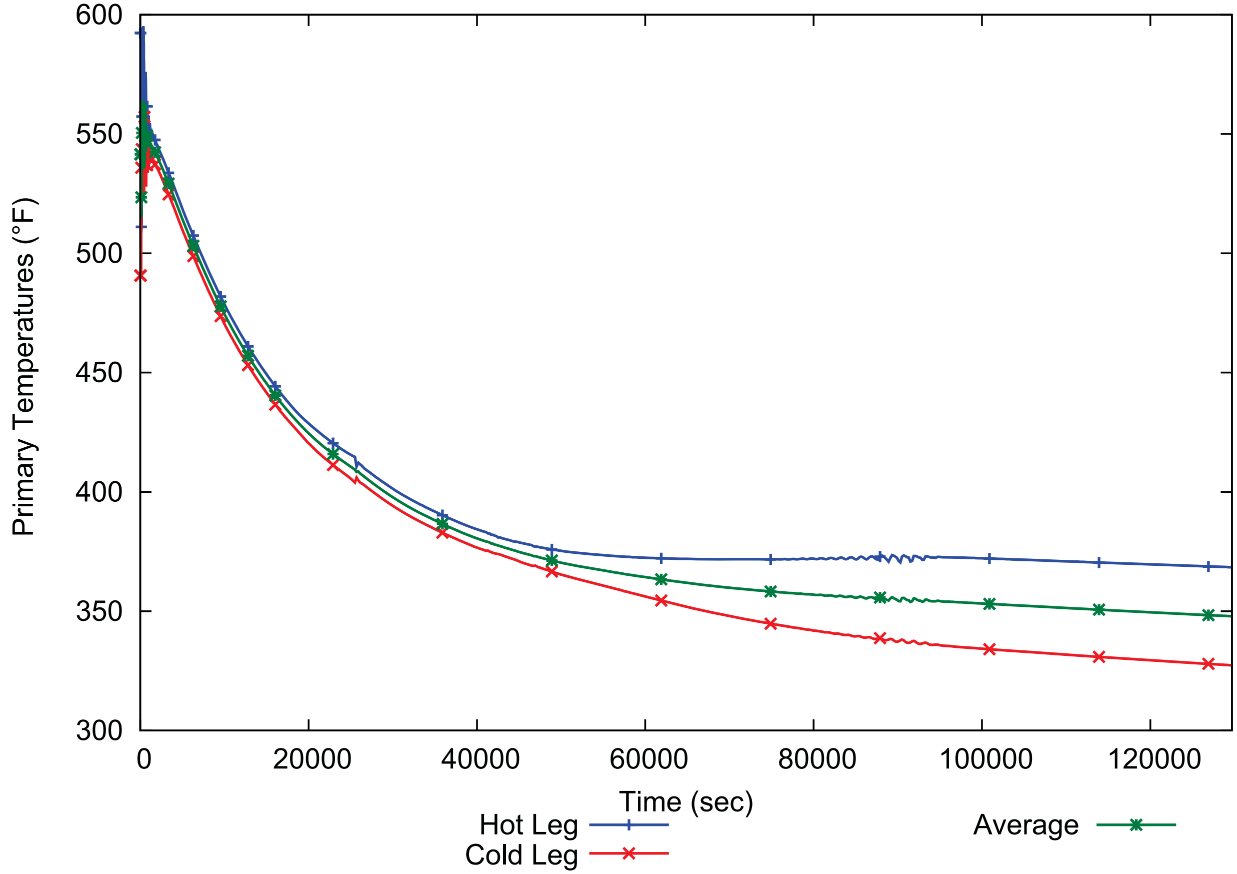


Figure 5.4-14: Primary Coolant Temperature Cooldown with Decay Heat Removal System One Train Operation: High System Inventory - 4 Hours

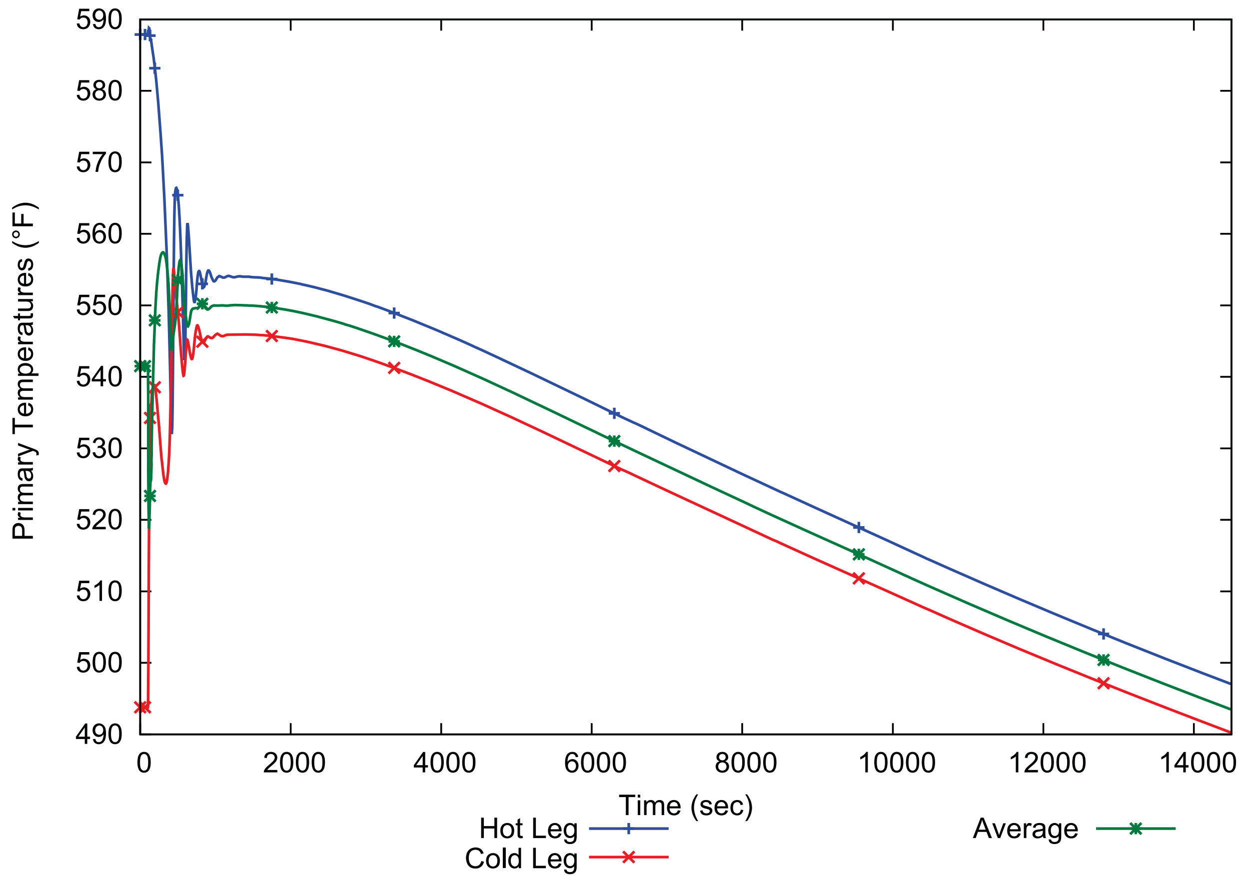


Figure 5.4-15: Primary Coolant Temperature Cooldown with Decay Heat Removal System One Train Operation: High System Inventory - 36 Hours

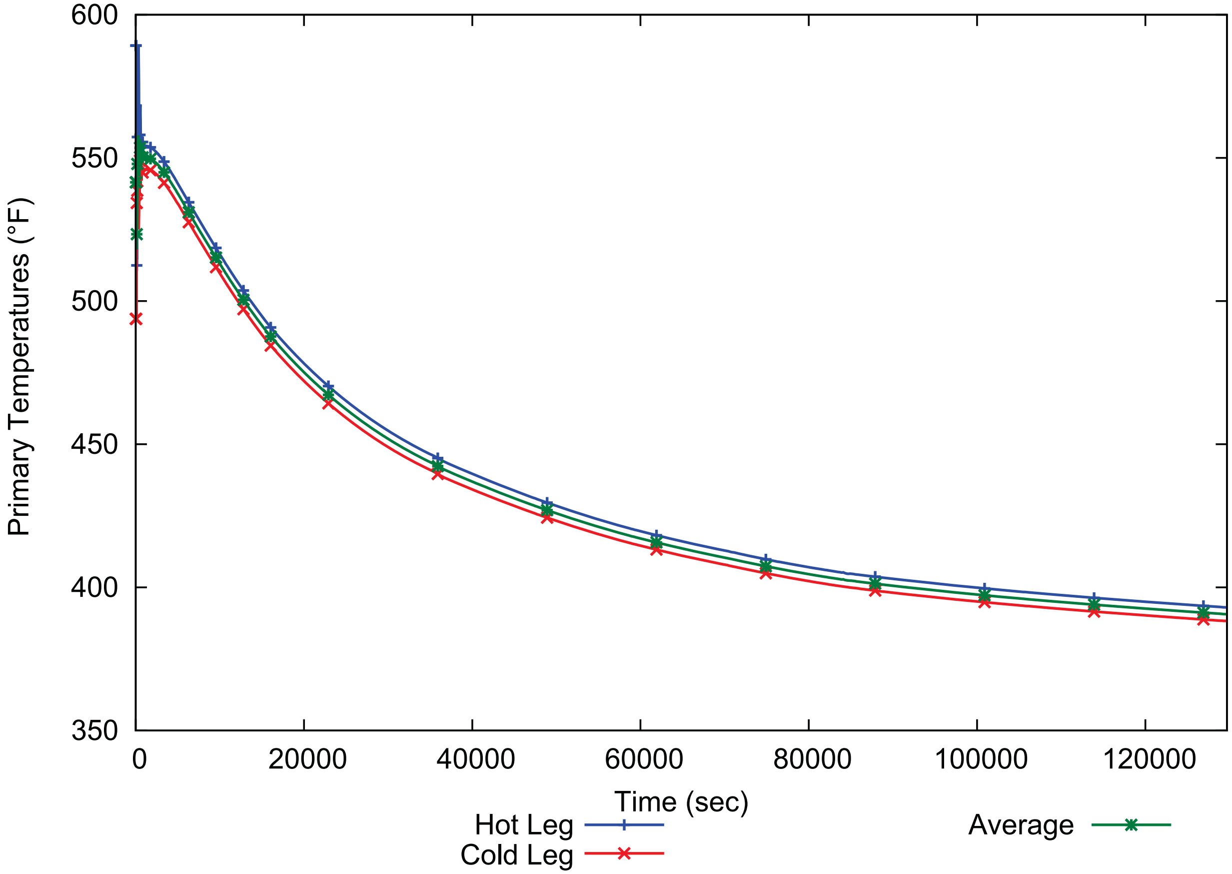


Figure 5.4-16: Primary Coolant Temperature Cooldown with Decay Heat Removal System One Train Operation: High System Inventory, 140 Degree Fahrenheit Initial Pool Temperature - 36 Hours

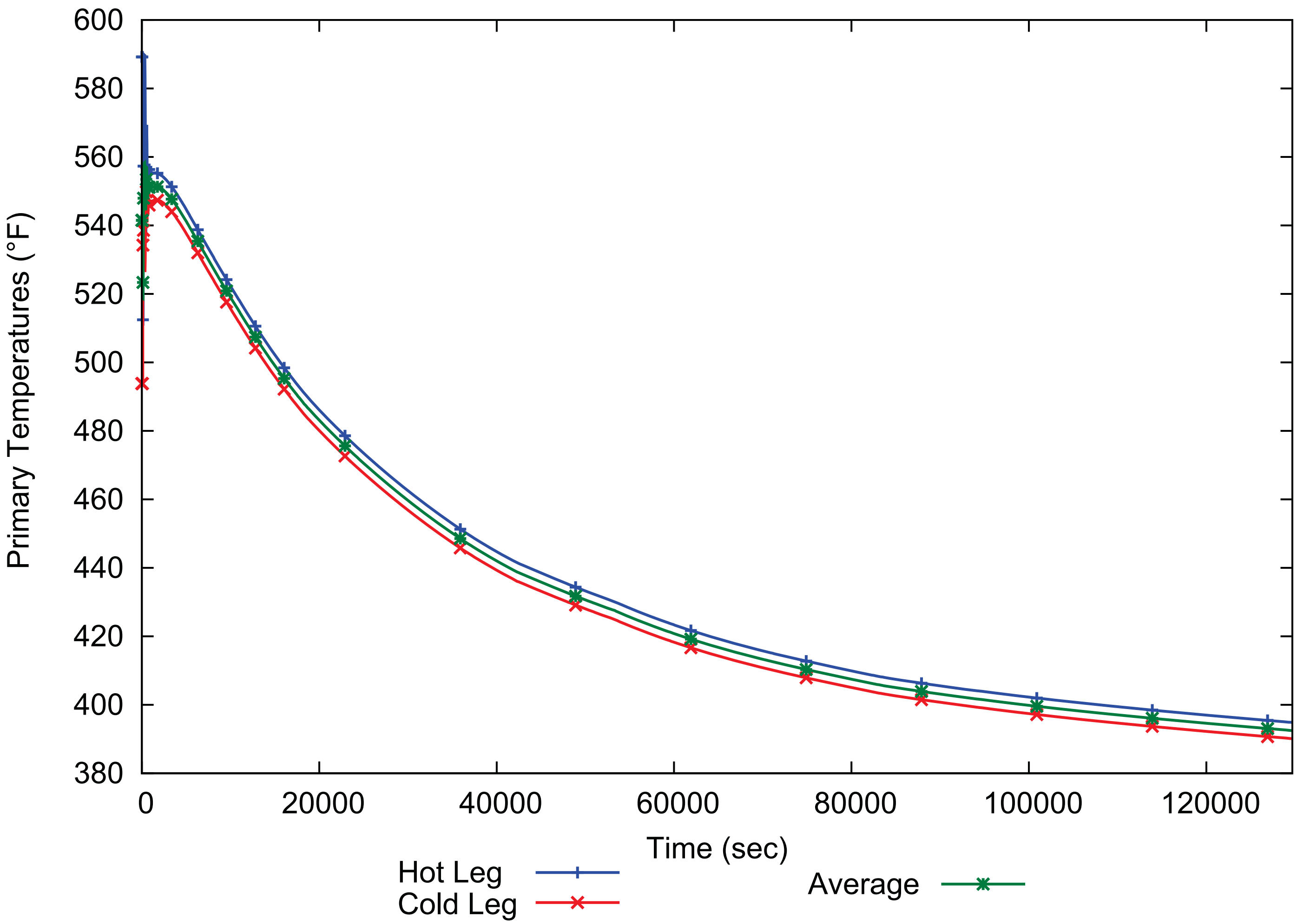


Figure 5.4-17: Pressurizer Region of Reactor Vessel