10. STEAM AND POWER CONVERSION SYSTEM

10.1 Introduction

Westinghouse Electric Company LLC (Westinghouse) proposed to the U.S. Nuclear Regulatory Commission (NRC) an alternative design for its steam and power conversion (SPC) system in its Technical Report (TR)-86, "AP1000 COL Standard Technical Report Submittal of APP-GW-GLN-018," Revision 0, dated February 8, 2007. On June 25, 2007, Westinghouse submitted Revision 1 to TR-86 and proposed a new standard design with a single turbine-generator and steam-cycle unit for all AP1000 plants. In Revision 17 to the AP1000 design control document (DCD), Tier 2, Section 10.2, "Turbine Generator," Westinghouse incorporated all the changes associated with the new standard design.

The most significant differences between the designs that the NRC evaluated in NUREG-1793, "Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design," issued September 2004, and the proposed new design of the main turbine-generator set are as follows:

(1) replacement of the mechanical overspeed protection with a diverse electrical overspeed trip;

(2) triplicate channels for turbine speed indication and turbine trip signal versus two redundant channels;

(3) three modes of turbine overspeed protection versus two modes;

(4) hydraulic trip manifold, which enables online testing;

(5) addition of 7th stage feedwater heaters;

(6) decrease in diameter from 137 centimeters (cm) (54 inch (in.)) to 132 cm (52 in.) for the low-pressure turbine last stage blade (LSB);

(7) addition of moisture extraction blades (MEB); and

(8) static excitation provided by solid-state thyristors versus brushless excitation;

In the AP1000 DCD, Tier 1, Revision 17, Section 2.4.2, Table 2.4.2-2, the applicant proposed adding an "emergency electrical overspeed trip device" as a component located in the turbine building.

In addition, the AP1000 DCD, Revision 17, Section 10.2, contains the following proposed changes:

- In DCD Tier 2, Section 10.2.6, "Combined License Information on Turbine Maintenance and Inspection," Westinghouse proposed revising the implementation timing for Combined License (COL) Information Item 10.2.6. This was identified as COL Action Item 10.5-2 in Section 10.5 of Appendix F, "Combined License Action Items," to NUREG-1793.

- In DCD Tier 2, Section 10.2.3.6, “Maintenance and Inspection Program Plan,” Westinghouse proposed revising the turbine valve testing intervals from quarterly to semiannually.

- In DCD Tier 2, Section 10.2, Westinghouse proposed a number of changes related to the layout and general arrangement in the turbine building as a result of replacing the original design with the alternative design, which includes an additional stage of feedwater heaters.

- In DCD Tier 2, Section 10.2.2.4, “Digital Hydraulic System Description”; Section 10.2.2.5 “Overspeed Protection”; and Table 10.2-2, “Turbine Overspeed Protection”; Westinghouse proposed revisions to reflect the replacement of the Toshiba Turbine Control System with an Ovation Turbine Control System.

- In DCD Tier 2, Figure 10.2-1, “Turbine Generator Outline Drawing” the applicant revised the drawing to provide consistency with the Toshiba Turbine-Generator Steam Cycle Design.

All other changes to Section 10.2 were determined by the staff to be editorial in nature and do not affect the conclusion in NUREG-1793, and are therefore acceptable.

10.2 Turbine Generator

The NRC staff reviewed all changes to the turbine generator, in accordance with Section 10.2, “Turbine Generator,” of NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” (hereafter referred to as the SRP). The new design of the turbine-generator system was evaluated against the requirements in Title 10 of the Code of Federal Regulations (10 CFR) Part 50, “Domestic Licensing of Production and Utilization Facilities.” Specifically, the design must meet the requirements of General Design Criterion (GDC) 4, “Environmental and Dynamic Effects Design Bases,” in Appendix A, “General Design Criteria for Nuclear Power Plants,” to 10 CFR Part 50, as they relate to protecting the structures, systems, and components (SSCs) that are important to safety from the effects of turbine missiles. GDC 4 provides guidance for the turbine overspeed protection system (with suitable redundancy and diversity) to minimize the generation of turbine missiles. SRP Section 10.2.II, “Acceptance Criteria,” describes the specific criteria needed to meet the requirements of GDC 4. Also, the staff used SRP Section 10.2.III, “Review Procedures,” to determine whether the preliminary design in the DCD meets the acceptance criteria in SRP Section 10.2.II.

The staff focused its review on changes 1 through 4 identified above, the COL Action Item 10.5-2, turbine valve testing, and the general layout arrangements, since these changes affect the protection of the turbine from overspeed conditions that could lead to the generation of turbine missiles. These items relate directly to the specific criteria described in Items 1 A and 1 C of SRP Section 10.2.II that are necessary to meet the requirements of GDC 4, as they relate to the turbine overspeed protection and periodic testing of components while the unit is operating at rated load. Also, the staff reviewed changes 5 through 8 identified above and determined that these changes do not affect the safety conclusions in NUREG-1793.

For the purpose of this evaluation, the NRC refers to the design of the turbine-generator system provided in the AP1000 DCD, Revision 15, and evaluated in Section 10.2 of NUREG-1793, as the “original” design. The staff refers to the alternative Toshiba design in the AP1000 DCD, Revision 17, as the “new” design.

The safety design bases and power generation design bases for the turbine generator are the same for both the original and new designs. The turbine generator of the new design is designated as Model TC6F, with a diameter of 132 cm (52 in.) for the low-pressure turbine LSB unit. The low-pressure turbine LSB in the original design had a diameter of 137 cm (54 in.). DCD Tier 2, Revision 17, Table 10.2-1, identifies the design parameters of the new design. DCD Tier 2, Revision 17, Figure 10.3.2-2, provides the piping and instrumentation diagram containing the stop, control, intercept, and reheat valves. Also, the new design consists of a double-flow, high-pressure turbine; three double-flow, low-pressure turbines; and two external moisture separator/reheaters. The difference between the two designs is that the new design has two reheating stages, while the original design had only one.

The single direct-driven generator is cooled by hydrogen gas and de-ionized water (water-cooled in the original design). Other related system components include a turbine-generator-bearing lubrication system, a digital electrohydraulic control (D-EHC) system with supervisory instrumentation, a turbine steam-sealing system, overspeed protective devices, turning gear, a stator cooling-water system, a generator hydrogen and seal oil system, a generator carbon-dioxide system, a rectifier section, an excitation transformer, and a voltage regulator. The D-EHC system, the overspeed protective devices, and the excitation system in the new design differ from those in the original.

The turbine-generation foundation in both designs is a spring-mounted support system. The springs dynamically isolate the turbine-generator deck from the remainder of the structure in the range of operating frequencies.

The turbine-generator cycle is basically the same for both designs. Steam from each of the two steam generators enters the high-pressure turbine through stop valves and control valves. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheater vessels. The reheated steam flows through separate reheat stop and intercept valves in each of six reheat steamlines leading to the inlets of the three low-pressure turbines. Turbine steam extraction connections are provided for seven stages of feedwater heating (six stages in the original design). Moisture separation in the new design differs from the original; however, the difference does not affect the evaluation and the staff's conclusion in NUREG-1793.

10.2.1 <u>Overspeed Protection</u>

A D-EHC system and an emergency trip system provided overspeed protection in the original design. The D-EHC system opened a drainpath for the hydraulic fluid in the overspeed protection control header, if the turbine exceeded 103 percent of rated speed. As a result of the loss of fluid pressure in the header, the control and intercept valves closed.

The emergency trip system tripped the turbine if speeds exceeded 110 percent of the rated speed. The emergency trip system has an emergency trip control block, trip solenoid valves, a mechanical overspeed device, three test trip blocks with pressure sensors and test solenoid valves, rotor position pickups, speed sensors, and a test panel. The mechanical overspeed trip device consisted of a spring-loaded trip weight mounted in the rotor extension shaft.

In the new design, the two systems that provide overspeed protection, the D-EHC control system and the electrical overspeed trip system, differ from those in the original.

The new D-EHC has three modes of operation to protect the turbine generator against overspeed. The first is the intercept-valves control function, which initiates closure of the intercept valves when the error between the demand position signal and the actual position signal of the intercept valve exceeds the setpoint. The second mode is load unbalance, which operates at greater than or equal to 30-percent load rejection. It causes all control and intercept valves to close quickly. The third mode is the emergency overspeed trip. All control valves and intercept valves are fully closed quickly by the actuation of each fast-acting solenoid valve of the electrical overspeed trip system.

The electrical overspeed trip system consists of redundant processors, three speed channel circuits, and trip relays. An independent electrical overspeed system replaces the mechanical overspeed device of the original design. A trip of the system opens a drainpath for the hydraulic fluid in the emergency trip supply. A loss of fluid pressure in the trip header causes the main stop and reheat valves to close. Also, a relay trip valve in the connection to the emergency trip supply opens to drop the pressure in the relay emergency trip supply and cause the control and intercept valves to close.

The specific criteria that apply to the Overspeed Protection related changes include 10 CFR 52.63(a)(1)(vi) in that the changes substantially increase overall safety, reliability, or security of facility design, construction, or operation, and the direct and indirect costs of implementation of the rule change are justified in view of this increased safety, reliability, or security, and 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

The following Sections 10.2.2 and 10.2.2.1 provide further details on the D-EHC and the electrical overspeed trip systems, respectively.

10.2.2 Digital Electrohydraulic Control System

The AP1000 DCD, Revision 17, Section 10.2.2.4, “Digital Electrohydraulic System Description,” states that the turbine generator is equipped with a D-EHC system that combines the capabilities of redundant processors and high-pressure hydraulics to regulate steamflow through the turbine. The system provides the functions of speed control, load control, and automatic turbine control. A hydraulic system, independent of the bearing lubrication system, provides valve opening actuation in the D-EHC system. Upon reduction or relief of fluid pressure, springs provide valve-closing actuation. The system is designed so that loss of fluid pressure, for any reason, leads to valve closing and, consequently, a turbine trip. Steam valves are provided in an in-line configuration. The overspeed trip system trips the stop valves; the control valves are modulated by the control system and are actuated by the trip system.

The speed control function of the D-EHC master controller provides speed control, acceleration, and overspeed protection. The speed error signal is derived by comparing the desired setpoint with the actual speed of the turbine. A failure of one speed input generates an alarm. The failure of two or more speed inputs generates an alarm and trips the turbine.

The speed control function exists in triplicate channels. The master controller speed function also contains 110-percent and 111-percent overspeed trips. The 110-percent trip signal is sent to a fast-acting solenoid valve in the hydraulic trip manifold that actuates closure of the stop, control, intercept, and reheat valves. An independent emergency electrical trip is available at 111-percent turbine speed, as a backup to the 110-percent electrical overspeed trip.

The load control function of the D-EHC develops signals that are used to regulate unit load. Signal inputs are based on a proper combination of the speed error and actual load setpoints (turbine megawatt) to generate flow demand on the control valves.

The automatic turbine control provides start up and loading of the turbine generator. The automatic turbine control programs monitor the applicable limits and precautions. When the operator selects the automatic turbine control, the programs both monitor and control the turbine. The automatic turbine control is capable of performing the following activities:

- changing speed
- changing acceleration
- generating speed holds
- changing load rates
- generating load holds

The staff's evaluation finds that the D-EHC system combines the capabilities of redundant processors and high-pressure hydraulics to regulate steamflow through the turbine. The control system provides the functions of speed control, load control, and the automatic turbine control, which may be used either for control or for supervisory purposes, at the option of the plant operator.

The D-EHC system employs three electric speed inputs with signals that are processed in redundant processors. A hydraulic system that is independent of the bearing lubrication system provides valve-opening actuation. Upon reduction or relief of fluid pressure, springs and steam forces provide valve-closing actuation. The system is designed so that a loss of fluid pressure, for any reason, leads to valve closing and consequent turbine trip.

The staff discusses the acceptability of the redundancy and diversity functions of the new D-EHC system design below.

The overspeed trips for the turbine consist of a 110-percent electrical trip and a 111-percent independent emergency electrical trip. In DCD Tier 2, Section 10.2.2.4.1, Westinghouse stated that the independent emergency electrical trip was available at 111-percent turbine speed, as a backup to the 110-percent electrical overspeed trip.

The electrical overspeed trip system includes an online testable hydraulic manifold, speed sensors, a trip relay, independent power supplies, and a test panel. The emergency trip supply pressure is established when the master trip solenoid valves are closed. The valves are arranged in two channels for testing purposes. Both valves in a channel will open to trip the channel. Both channels must trip before the emergency trip supply pressure collapses to close the turbine steam inlet valves. Each tripping function of the electrical emergency trip system can be individually tested either by the operator or from the test panel, without tripping the turbine, by separately testing each channel of the appropriate trip function. The solenoid valves may be individually tested.

The 110-percent electrical overspeed trip system has triplicated (i.e., redundant) speed sensors, separate from the 111-percent emergency electrical overspeed trip speed sensors, that provide backup overspeed protection, and use the master trip solenoid valves in the master trip device to drain the emergency trip hydraulic supply. The hydraulic fluid in the trip and overspeed protection control headers is independent of the bearing lubrication system to minimize the potential for contamination of the fluid.

Separate instruments sense low bearing oil pressure, low electrohydraulic fluid pressure, and high condenser back pressure. Each assembly consists of triplicate pressure transmitters with instrument valves. Each assembly is arranged into three channels. If two of the three signals (pressure or vacuum) reach a trip setpoint, then the pressure sensors cause the master trip device to operate. A test device can check the trip function by simulating pressure to activate the trip outputs from the modules.

The mechanical overspeed device, evaluated in NUREG-1793, has been replaced with an independent, diverse electrical overspeed trip system. The electrical overspeed trip system consists of redundant processors, three speed channel circuits, and trip relays, as well as other protective functions, such as trip anticipations and power load unbalance detection. The overspeed controllers execute offline and online testing, both of which are conducted from the control room and require no technicians at the turbine. Offline testing is performed during startup and trips the turbine, based on an internal setpoint rather than actual turbine speed. Online testing is automatically executed through the internal injection of a ramping signal into all three independent speed channels at once. This test verifies the proper operation of the software, the hardware, and the components of the hydraulic trip manifold. Loss of one signal will neither cause nor prevent a trip; however, failure of two of the three channels will initiate a turbine trip.

Regarding redundancy, Westinghouse stated that its design achieves additional redundancy by using three speed channel circuits in the master controller of the D-EHC turbine control system. The master controller is the primary controller for starting, synchronizing, and megawatt-loading the turbine/generator. This emergency overspeed trip system residing in the master controller is redundant, independent, and diverse to the electrical overspeed trip system, as discussed above. Each speed channel also has its own independent tripping relays. Loss of one signal will neither cause nor prevent a trip. Further, Section 3.0, "Technical Background," of TR-86, Revision 1, states: "Both the electrical overspeed trip system and the emergency overspeed trip systems in the master controller meet the single-failure criterion and are testable when the turbine is in operation." However, the NRC staff's review of the DCD markup could not find any commitment for either the electrical overspeed trip system or the emergency overspeed trip system in the master controller to meet the single-failure criterion. Item 1.A of SRP Section 10.2 states that the overspeed protection system should meet the single-failure criterion and should be testable when the turbine is in operation. Therefore, in Request for Additional Information (RAI)-SRP10.2-SBPA-01, the staff asked Westinghouse to provide additional information and justification for its claim that its design meets the SRP guidance for the single-failure criterion.

In its response to RAI-SRP10.2-SBPA-01, in a letter dated June 20, 2008, Westinghouse stated that the detailed design of the emergency overspeed trip system for AP1000 is still being completed and that the overspeed protection system design will meet the SRP guidance for the single-failure criterion. Westinghouse is to provide a date for the completed design. The staff had identified this as Open Item (OI)-SRP10.2-SBPA-01.

The applicant addressed the single failure criteria in its response to RAI-SRP10.2-SBPA-02, dated June 12, 2009. The response included a mark-up of DCD Tier 2 Section 10.2.2.5.3 stating that the overspeed protection system will function for abnormal conditions, including a single failure of any component or subsystem. The staff finds the DCD mark-up meets the SRP guidance and is acceptable. Therefore, the Open Item OI-SRP 10.2-SBPA-01 is considered closed. However, this remains as Confirmatory Item **(CI)-SRP 10.2-SBPA-01** pending a revision to the DCD that includes this mark-up.

With respect to the diversity of overspeed protection, in an earlier request, in Item 3 of RAI-TR86-SBPB-01, the staff asked Westinghouse to compare the reliability of the proposed turbine overspeed protection capability to the reliability that is afforded by the diverse capability for existing plants. In its letter response dated July 27, 2007, Westinghouse stated: "Another degree of diversity is provided by the software based trip that takes the speed reading from the input/output (I/O) modules and applies control builder logic to determine the trip function which is then output via separate relay modules." The Westinghouse response did not specify whether this applies to the primary overspeed trip of 110 percent, or the emergency backup overspeed trip of 111 percent, or both. The staff could not find any further details on the software configuration for the overspeed trip system, either in the changes to Revision 16 of the DCD identified in TR-86 or in the responses to other RAIs. The staff's concern is that, if both the 110-percent and 111-percent overspeed trips use the same software, a common-cause failure (CCF) could render both systems inoperable. Also, Item 2.A of SRP Section III states that the defense-in-depth provided by the turbine-generator protection system to preclude excessive overspeeds should include diverse protection means. Therefore, with respect to diverse protection against CCF in its design, the staff asked Westinghouse, in RAI-SRP10.2-SBPA-02, to provide further details to show that it meets the SRP guidance, as described above.

In response to RAI-SRP10.2-SBPA-02, Westinghouse stated that the original design approach was to use Ovation speed detector module firmware for both trips in parallel with an Ovation controller software-based logic that provides a level of redundancy and diversity. Now, Westinghouse has committed to implementing the two overspeed trips using diverse (hardware and software/firmware) electronic means (i.e., one of the trips will not be implemented using the Ovation speed detector module), so that the 110-percent and 111-percent trips are not susceptible to a common-cause software failure that would render them both inoperable. The staff finds that this commitment meets the guidance described in Item 2.A of SRP Section 10.2.III, which states: "The design of the in-depth defense provided by the turbine-generator protection system to preclude excessive overspeeds should include diverse protection means." The staff finds this acceptable; however, the staff's position is that Westinghouse should update the Tier 1 and Tier 2 sections of the DCD, with inspections, tests, analyses, and acceptance criteria (ITAAC), to confirm that the design acceptance criteria requiring diverse hardware, firmware, and software between the two overspeed trips are met. The staff had identified this as OI-SRP10.2-SBPA-02a.

Revision 3 of the applicant's response to RAI-SRP10.2-SBPA-02a, dated December 28, 2009, addresses OI-SRP10.2-SBPA-02a. The applicant provided a mark-up of DCD Tier 1 Table 2.4.2-1 (ITAAC) where design commitment 3 has been added which addresses the applicant's commitment to provide adequate diversity between the two electrical overspeed trips. The design commitment 3 states: "The trip signals from the two turbine electrical overspeed protection trip systems within the PLS are isolated from, and independent of, each other." For the Inspections, Tests, and Analyses of this ITAAC, the applicant identified three subparts which include: i) the system design review, ii) testing of the as-built system, and iii) an inspection to be performed for the existence of a report verifying that the two turbine electrical overspeed protection systems have diverse hardware and software/firmware. Further, the applicant described an associated acceptance criteria for each of these inspections, tests, and analyses, where the Acceptance Criteria 3.iii stating: "A report exists and concludes that the two electrical overspeed protection systems within the PLS have diverse hardware and software/firmware." The staff finds this ITAAC acceptable since it ensures that the two electrical overspeed protection systems consist of diverse hardware and software/firmware.

Additionally, in the same December 28, 2009 response, the applicant provided a mark-up of DCD Tier 2 Section 10.2.2.5.3, where it states that the 110% and 111% trip systems have diverse hardware and software/firmware to eliminate common cause failures (CCFs) from rendering the trip functions inoperable. Also in the response, the applicant added Figure 10.2-2, “Emergency Trip System Functional Diagram,” to the end of DCD Tier 2 Section 10.2, which shows schematically the diverse hardware and software/firmware of the overspeed trip systems. The staff finds the DCD Tier 1 and 2 mark-ups and added Tier 2 Figure 10.2-2 acceptable as they meet the guidance in Item 2.A of SRP Section 10.2.III. Therefore, Open Item OI-SRP 10.2-SBPA-02a is considered closed. However, this remains as **CI-SRP 10.2-SBPA-02a** pending a revision to the DCD that reflects this mark-up and added figure.

Also, in SRP Section 10.2.III, Item 2.D, the guidance states: “An independent and redundant backup electrical overspeed trip circuit senses the turbine speed by magnetic pickup and closes all valves associated with speed control at approximately 112 percent of rated speed.” However, the Westinghouse response to the above RAI does not state whether the electrical backup senses the turbine speed by magnetic pickup. The staff had identified this as OI-SRP10.2-SBPA-02b.

In its response to RAI-SRP10.2-SBPA-02, dated June 12, 2009, the applicant provided a mark-up of DCD Tier 2 Section 10.2.2.5.3 where it is stated that an independent and redundant backup electrical overspeed trip circuit senses the turbine speed by magnetic pickup and closes all valves associated with speed control at approximately 111 percent of rated speed. The staff finds the DCD mark-up acceptable as it meets the guidance in SRP Section 10.2.III-2c. Therefore, Open Item OI-SRP 10.2-SBPA-02b is considered closed. However, this remains as **CI-SRP 10.2-SBPA-02b** pending a revision to the DCD that reflects this mark-up.

In RAI-SRP10.2-SBPA-04, the staff asked Westinghouse to provide a timeframe for completion of the system design and submittal of an analysis of failure modes and effects; specifically, common-mode failures of the software for the 110- and 111-percent overspeed protection features. In response to RAI-SRP10.2-SBPA-04, Westinghouse stated that, based on its response to RAI-SRP10.2-SBPA-02 on the diversity of the two turbine overspeed trips provided for the 110-percent and the 111-percent speed points, an analysis would not be necessary; the staff finds this acceptable.

Further, SRP Section 10.2.III, Item 2.B, states: “For normal speed-load control, the speed governor of the electrohydraulic control system fully cuts off steam at approximately 103 percent of rated turbine speed by closing the control and intercept valves.” The original design contained this provision, as shown in Table 10.2-2 in Revision 15 to the AP1000 DCD. However, for the new design, Westinghouse eliminated the 103-percent trip without providing any justification in Revision 16 of the DCD or in TR-86, Revision 1. Therefore, in RAI-SRP10.2-SBPA-03, the staff asked Westinghouse to justify the elimination of the 103-percent trip.

In response to RAI-SRP10.2-SBPA-03, in a letter dated July 31, 2008, Westinghouse stated that the 103-percent trip value previously provided in Table 10.2-2 in Revision 15 of the DCD was not for a turbine-trip condition. The described condition was for the speed-control mode of the turbine-control system for a load reject event and a generator breaker open condition. Westinghouse eliminated the 103-percent value from DCD Table 10.2-2 because the Toshiba turbine valves and hydraulic system are not designed to fully close at the 103-percent rated speed. The control valves are closed at approximately 105 percent of rated turbine speed, and the intercept valves are closed at approximately 107 percent of rated speed. However, before these overspeed points are reached, the control valves and intercept valves begin to close at 101 percent of the rated turbine speed, as stated in DCD Table 10.2-2. The system is designed to prevent the peak transient of 108 percent of rated speed from being exceeded, as stated in the table. Westinghouse stated that this had not changed from DCD, Revision 15—as speed is reduced, the valves will reopen and modulate as needed to achieve and maintain 100-percent rated speed. The staff accepts the Westinghouse response to RAI-SRP10.2-SBPA-03, for the reasons explained above, as well as the Westinghouse explanation that it had eliminated the 103-percent value from DCD Table 10.2-2 because of the new Toshiba design.

In Tier 1 Section 2.4.2, Table 2.4.2-2 of the AP1000 DCD, Revision 17, the applicant added the emergency electrical overspeed trip device as a component located in the turbine building. This component, in conjunction with the electrical overspeed trip device (which is already listed in Tier 1 Table 2.4.2-2) provides the diversity and redundancy for the turbine overspeed trip function that are specified by SRP Section 10.2. The NRC staff agrees that the emergency electrical overspeed trip device is an important design feature that should be included in the Tier 1 design description for the main turbine system. Therefore, the addition of the emergency electrical overspeed trip device as a component located in the turbine building in Tier 1 Table 2.4.2-2 is considered to be acceptable.

10.2.3 Conclusion

In NUREG-1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B, “Standard Design Certifications,” to 10 CFR Part 52, “Licenses, Certifications, and Approvals for Nuclear Power Plants,” that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed the changes Westinghouse proposed to the AP1000 turbine generator in AP1000 DCD, Revision 17. The staff finds that incorporating the proposed changes does not adversely affect the ability of the turbine generator to meet the applicable acceptance criteria in SRP Section 10.2. The staff also finds that Westinghouse has properly incorporated the design changes into the appropriate sections of the AP1000 DCD, Revision 17. Because the AP1000 turbine-generator design continues to meet all applicable acceptance criteria and the changes are properly documented in the updated AP1000 DCD, the staff finds that all of the changes to the AP1000 turbine generator are acceptable.

In addition, the changes establish the proposed Toshiba design as the single, standard design for all AP1000 plants. These DCD changes are generic and are expected to be included in all COL applications referencing the AP1000 certified design. At this time, the NRC has not issued a COL for any AP1000 plant. Thus, the proposed changes incorporated into Revision 17 contribute to the increased standardization of the certification information in the AP1000 DCD.

10.2.5 Valve Control

10.2.5.1 Summary of Technical Information

SRP Section 10.2, Criterion II.1.B, states that the applicant should provide turbine main steam stop and control valves and reheat steam stop and intercept valves to protect the turbine from exceeding set speeds, as well as to protect the reactor system from abnormal surges. To ensure that turbine overspeed is controlled within acceptable limits, the reheat stop and intercept valves should be capable of closure concurrent with the main steam stop valves or of sequential closure within an appropriate time limit. The valve arrangements and valve closure times should ensure that a failure of any single valve to close will not result in an excessive turbine overspeed in the event of a turbine-generator system trip signal.

10.2.5.2 Evaluation

The valve arrangement in the new design is basically the same as in the original design, with the following exception: The No. 2 and No. 4 stop valves in the new design have a bypass valve, which is controlled by an electrohydraulic servo actuator for control valve warming. The closure time for all stop, control, reheat, and intercept valves is 0.3 seconds for both the new and the original design.

The specific criterion that applies to the change evaluated above is 10 CFR 52.63(a)(1)(vi) in that the change substantially increases overall safety, reliability, or security of facility design, construction, or operation, and the direct and indirect costs of implementation of the rule change are justified in view of this increased safety, reliability, or security.

10.2.5.3 Conclusion

On the basis of its review, the staff finds that the design change is acceptable, because the availability and adequacy of the control valves in the AP1000 design conform to Criteria II.1.B and II.3 in SRP Section 10.2.

10.2.8 Turbine Rotor Integrity

10.2.8.1 Summary of Technical Information

In the AP1000 DCD, Revision 16, Westinghouse proposed an alternative SPC design that includes changing the design of the turbine rotors from a Westinghouse/Mitsubishi model to a Toshiba model. This evaluation addresses only the turbine-rotor design change. Revision 0 of TR-86, dated February 8, 2007, provided the technical justification for the proposed changes. Revision 1 of TR-86, submitted on June 25, 2007, established the Toshiba design as the single, standard turbine-rotor design for all AP1000 plants. A Westinghouse letter, dated July 12, 2007, included additional information on the TR. The staff evaluates the rotor design and probability of missile generation for the Toshiba turbine design below. The AP1000 DCD, Revision 16, incorporates the design changes.

10.2.8.2 Evaluation

GDC 4 requires SSCs important to safety to be appropriately protected against environmental and dynamic effects, including the effects of missiles, that may result from equipment failure. The staff reviewed the AP1000 DCD changes related to this section that ensure turbine-rotor integrity and a low probability that turbine-rotor failure will result in the generation of missiles.

In the AP1000 DCD, Revision 16, Westinghouse proposed a change to the design of the turbine rotors from a Westinghouse/Mitsubishi model to a Toshiba model. The Toshiba design includes two types of bucket (blade) fixations instead of side-entry blades, as in the Westinghouse/Mitsubishi design. The two types of fixations are an outside dovetail and a fork-type dovetail. The outside dovetail will be used in every stage of the high-pressure turbine and the fork-type dovetail will be used in the last two stages of the low-pressure turbine.

As a result of the design change, Westinghouse performed a new analysis of the missile generation probability for fully integral rotors of the Toshiba turbine-generator design. Westinghouse TR WCAP-16650-P, Revision 0, "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low-Pressure Turbines," issued February 2007, includes the methodology and results of the analysis. This report evaluates the probability of missiles resulting from four failure mechanisms: ductile burst from destructive overspeed, high-cycle fatigue cracking, low-cycle fatigue cracking, and stress-corrosion cracking. The staff reviewed the methodology used in WCAP-16650-P and its applicability to the Toshiba design. The Westinghouse analysis concluded that an inspection interval of up to 24 years was sufficient to satisfy the requirement that the probability of missile generation be less than 1.0×10^{-5} per year. Westinghouse included conservative assumptions in its analysis for parameters such as the stress required for ductile burst, the probability for stress-corrosion crack initiation, the probability of rotor overspeed, and the number of startup and shutdown cycles. In RAI-SRP10.2.3-CIB1-01, the staff requested additional information about the way in which the new missile probability analysis addressed high-trajectory missiles.

In a letter dated June 20, 2008, Westinghouse stated that the AP1000 design has a favorable turbine orientation that prevents turbine missiles from causing unacceptable damage to safety-related SSCs. The analysis in WCAP-16650-P demonstrates that, for high-trajectory missiles, the probability of generating a missile from a burst turbine rotor (P1) is 10^{-5}. This meets the guidance in SRP Section 3.5.1.3 of 10^{-4} for a favorable turbine orientation and 10^{-5} for an unfavorable turbine orientation. The staff finds this acceptable, because the Westinghouse analysis for high-trajectory missiles meets the guidance in SRP Section 3.5.1.3.

Westinghouse also stated that the analysis in WCAP-16650-P applies only to high-trajectory missiles and that high-velocity, low-trajectory missiles cannot directly strike safety-related systems and components. However, the turbine generators at dual-unit sites must be considered unfavorably oriented, because safety-related systems and components are in the low-trajectory missile strike zone. Therefore, to address COL applications for dual-unit sites, the staff requested that the applicant provide a bounding turbine missile analysis for low-trajectory missiles or provide a COL Action Item that requires COL applicants to provide a turbine missile analysis for low-trajectory missiles at dual-unit sites. In a letter dated April 13 2009, Westinghouse stated that WCAP-16650 also applies to low-trajectory turbine missiles for dual unit sites that have unfavorable orientation. However, Westinghouse did not provide justification for applying this analysis for low-trajectory turbine missiles, and did not address whether the analysis is dependent on missile trajectory. The staff identified this as OI-SRP10.2.3-CIB1-01.

In a letter dated September 22, 2009, Westinghouse provided further clarification of the applicability of WCAP-16650. Westinghouse stated that WCAP-16650-P determines the probability of generating a missile due to a burst turbine rotor, regardless of whether the missile is high-trajectory or low-trajectory. In addition, Westinghouse stated that the AP1000 DCD does not consider low-trajectory missiles for a single unit site. However, if a dual unit site is considered, the probability, P1, from WCAP-16650-P can be used to evaluate low-trajectory missiles. Therefore, the staff finds that since the angle of trajectory is not used in WCAP-16650-P for determining the total probability of generating a missile due to a burst turbine rotor, P1, the results of the analysis can be used for both low and high-trajectory missiles. The P1 result from WCAP-16650-P is then used to ensure that the probability of striking SSCs, P4, is less than 10^{-7} per the guidance of RG 1.115 and SRP Section 3.5.1.3. On this basis, the staff finds the response acceptable, and OI-SRP10.2.3-CIB1-01 is closed.

Based on the conservative assumptions incorporated into this analysis and the fact that the rotors will be inspected during plant operation at approximately 10-year intervals, the staff finds the methodology and results acceptable. The staff, therefore, finds the proposed rotor design changes acceptable, because they do not change the probability of missile generation for fully integral low-pressure rotors previously accepted by the NRC staff in NUREG-1793.

The NRC staff reviewed the proposed changes as they relate to Revision 16 of the AP1000 DCD. The changes establish the proposed design as the single, standard design for all AP1000 plants. These DCD changes are generic and are expected to be included in all COL applications referencing the AP1000 certified design. At this time, the NRC has not issued a COL for any AP1000 plant. Thus, the proposed changes incorporated into Revision 16 contribute to the increased standardization of the certification information in the AP1000 DCD.

10.2.8.3 Conclusion

Based on the above evaluation, the staff concludes that the AP1000 design change is acceptable, because it meets the requirements of GDC 4 and does not change the probability of missile generation for fully integral rotors that the NRC staff previously accepted. Furthermore, the staff finds that the conclusions regarding the proposed turbine-rotor design and the methodology for analyzing the probability of missile generation are expected to apply to all COL applications referencing the AP1000 design certification. Therefore, the proposed DCD changes are acceptable, under 10 CFR 52.63(a)(1)(vii), on the basis that they contribute to the increased standardization of the design certification information.

10.2.10 Valve Testing Intervals

10.2.10.1 Summary of Technical Information

Section 10.2.3.6 of the AP1000 DCD, Revision 16, proposed a decrease in the frequency of turbine-valve testing from every 3 months to every 6 months. To support this change, Westinghouse submitted TR WCAP-16651-P, Revision 0, “Probabilistic Evaluation of Turbine Valve Test Frequency,” issued February 2007. This report is similar to WCAP-15785, issued April 2002, with the same title, which used the same methodology to evaluate turbine-valve test frequency for the Westinghouse/Mitsubishi turbine design proposed in Revision 15 of the AP1000 DCD. The methodology in WCAP-16651-P is based on an analysis of the operating experience with Toshiba Corporation nuclear steam turbines. The applicant introduced the change into Revision 16 of the DCD by replacing the word “quarterly” with “six-month” or “semi-annual” as follows:

> Turbine valve testing is performed at six-month intervals. The semi-annual testing frequency is based on nuclear industry experience that turbine-related tests are the most common cause of plant trips at power. Plant trips at power may lead to challenges of the safety-related systems. Evaluations show that the probability of turbine missile generation with a semi-annual valve test is less than the evaluation criteria.

10.2.10.2 Evaluation

For the plant-specific turbine-rotor test data, the current COL Information Item 10.2-1 states that the COL holder “will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis.”

Westinghouse proposed to revise this information item by adding, to the end, the following time commitment: "prior to fuel load after the fabrication of the turbine." TR-6, "AP1000 As-Built COL Information Items" (APP-GW-GLR-021), Revision 0, issued June 2006, stated that an applicant cannot provide the as-built data at the time of the COL application. This justification is appropriate because the as-built material data for turbine rotors will not be available until the rotor material is procured for fabrication. In addition, the proposal to provide the as-built data before fuel load after the fabrication of the turbine is acceptable for reasons similar to those allowing the deferral of the maintenance and inspection program.

Regarding the proposal to extend the valve-test interval from 3 months to 6 months, the analysis in WCAP-16651-P showed that, for a favorably oriented turbine, the missile-probability criterion of 10^{-4} per year could be met, based on the operating experience with Toshiba turbines. In response to RAI-SRP10.2.3-CIB1-02, the applicant confirmed that the AP1000 turbine has a favorable orientation with respect to high-trajectory missiles. The analysis also concluded that the turbine-missile probability criterion of 10^{-5} per year could be met with a 6-month valve-test interval. This is significant because, for dual-unit sites, the turbine orientation is considered unfavorable with respect to low-trajectory missiles potentially striking safety-related systems and components. In response to RAI-SRP10.2.3-CIB1-02, the applicant provided clarifying information about the calculations used to determine the probability of missile generation, based on the frequency of valve tests.

The analysis presented in WCAP-16651-P, along with clarifying information provided in response to RAI-SRP10.2.3-CIB1-02, indicates that the existing operating experience for Toshiba turbines supports a missile generation probability of less than 10^{-5} per year, using 95-percent confidence-level values for the system separation frequency and valve-failure frequency. Therefore, based on the information provided, the staff concludes that the 6-month valve testing frequency meets the missile generation acceptance criteria for both favorable orientation (10^{-4} per year) and unfavorable orientation (10^{-5} per year).

However, the staff notes that an apparent error exists in Table 6-5 of WCAP-16651-P Rev. 0. Based on the equation given on page 18 of WCAP-16651-P Rev.0, the staff's calculations indicated that, for a 6-month valve-test interval, the value of "probability of a turbine missile" for "1/Time Interval" was an order of magnitude lower than the value shown in Table 6-5. The value in Table 6.5 of Rev. 0 does not support a six-month valve test frequency, and the staff identified this as OI-SRP10.2.3-CIB1-02. In a letter dated July 10, 2009, the applicant addressed this OI by submitting WCAP-16651-P, Rev. 1. The applicant confirmed that the exponent in the probability value in Table 6-5 of Rev. 0 was a typographical error. The corrected value in Table 6-5 of Rev. 1 is consistent with the applicant's calculated value of the annual probability of a turbine missile that was used to support the six-month valve test interval. Therefore, OI-SRP10.2.3-CIB1-02 was closed.

10.2.10.3 Conclusion

Based on this evaluation, the staff concludes that the DCD changes meet the requirements of GDC 4 and thus are acceptable. The proposed DCD changes are acceptable, under 10 CFR 52.63(a)(1)(vii), on the basis that they contribute to the increased standardization of the certification information.

10.2.11 Turbine Rotor Maintenance and Inspection Program

10.2.11.1 Summary of Technical Information

The AP1000 DCD, Revision 16, revised COL Information Item 10.2-1 to change the timing for the COL holder to provide information on the turbine-rotor maintenance and inspection program from within 3 years of obtaining a COL until prior to fuel load. NUREG-1793 also discusses this information item under COL Action Item 10.5-2. TR-6 justified the revision to COL Information Item 10.2-1. Revision 16 also proposed a decrease in the frequency of turbine-valve testing from every 3 months to every 6 months.

In the AP1000 DCD Tier 2, Revision 15, Section 10.2.6, COL Information Item 10.2-1 states the following:

> The Combined License holder will submit to the staff for review and approval within 3 years of obtaining a Combined License, and then implement a turbine maintenance and inspection program. The program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in Subsection 10.2.3.6. The Combined License holder will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis.

In the AP1000 DCD, Revision 16, Westinghouse proposed a modification to COL Information Item 10.2-1 by changing the COL holder commitments to "prior to fuel load." The proposed revision to DCD Tier 2, Section 10.2.6, states the following:

> The Combined License holder will submit to the NRC staff for review prior to fuel load, and then implement a turbine maintenance and inspection program. The program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in Subsection 10.2.3.6. The Combined License holder will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis prior to fuel load after the fabrication of the turbine.

10.2.11.2 <u>Evaluation</u>

GDC 4 requires that SSCs important to safety be appropriately protected against environmental and dynamic effects, including the effects of missiles, that may result from equipment failure. The staff reviewed the AP1000 DCD changes related to this section that ensure turbine rotor integrity and a low probability of missile generation caused by turbine rotor failure.

COL Information Item 10.2-1 addressed two issues: the turbine maintenance and inspection program and the plant-specific turbine rotor test data. TR-6 proposed modifications to both commitments.

For the turbine maintenance and inspection program, TR-6 states the following:

> A turbine maintenance and inspection program that is consistent with the frequency in DCD Subsection 10.2.3 does not need further approval from the NRC. The testing and inspection frequency in DCD Subsection 10.2.3 are supported by evaluations that are based on operating and inspection program experience in operating power plants.

For the maintenance and inspection program, Westinghouse proposed that the current COL Information Item 10.2-1 replace the commitment "submit to the staff for review and approval within 3 years of obtaining a Combined License" with "submit to the NRC staff for review prior to fuel load." With respect to the proposed change in valve-test frequency, the staff requested, in RAI-SRP10.2.3-CIB1-02, that the applicant clarify the analysis in WCAP-16651-P with respect to the evaluation criterion.

Since the deferral of the activities in the COL information item does not alter the design of the turbine, turbine valves, or connected piping systems, it will not affect turbine rotor integrity. Further, this change does not involve a test or experiment, does not affect design features associated with the mitigation of severe accidents, and does not alter barriers or alarms that affect security assessments of the AP1000. Therefore, the staff finds the Westinghouse revised COL Information Item 10.2-1 to be acceptable. This determination is also consistent with the acceptance criteria in SRP Section 10.2.3, "Turbine Rotor Integrity."

10.2.11.3 Conclusion

Based on this evaluation, the staff concludes that the DCD changes meet the requirements of GDC 4 and thus are acceptable. Furthermore, the staff finds that the TR-6 conclusions regarding the submittal and availability of COL holder information for a turbine-rotor maintenance and inspection program are generic and are expected to apply to all COL applications referencing the AP1000 design certification. Therefore, the proposed DCD changes are acceptable, under 10 CFR 52.63(a)(1)(vii), on the basis that they contribute to the increased standardization of the certification information.

10.3 Main Steam Supply System

10.3.1 Main Steam Supply System Design

10.3.1.1 Summary of Technical Information

In NUREG-1793, the staff approved Section 10.3, "Main Steam Supply System (MSSS)," of the AP1000 DCD, Revision 15. In the AP1000 DCD, Revisions 16 and 17, the applicant proposed changes to this section, supported by the following Westinghouse reports: TR-86, "Alternate Steam and Power Conversion Design" (APP-GW-GLN-018) Revision 1, issued June 25, 2007; TR-103, "Fluid System Changes" (APP-GW-GLN-019), Revision 2, dated January 29, 2008; and TR-125, "Corrections to Tier 1 ITAAC 2.2.4 and Tier 2 Section 3.6.1.3.3 and 10.3" (APP-GW-GLR-125), Revision 0, issued May 2007.

10.3.1.2 Evaluation

The staff reviewed the changes to the AP1000 DCD, Revision 15, Section 10.3, that are described in Revision 16, and a portion of the changes described in Revision 17. NUREG-1793 contains the regulatory basis for Section 10.3 of the AP1000 DCD. The staff reviewed the proposed changes to DCD Section 10.3 against the applicable acceptance criteria in SRP Section 10.3, "Main Steam Supply System." Those changes that involve NRC review considerations as reflected in SRP Section 10.3 are described and evaluated in this section. The specific criteria that apply to the MSSC design related changes include 10 CFR 52.63(a)(1)(vi) in that the changes substantially increases overall safety, reliability, or security of facility design, construction, or operation, and the direct and indirect costs of implementation of the rule change are justified in view of this increased safety, reliability, or security, and 10 CFR

52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information. The results of the staff's evaluation are provided as follows:

(1) Section 10.3.2.2.4, "Main Steam Isolation Valves," page 10.3-8:

The staff reviewed the applicant's additional language stating that, on loss of electric power, the main steam isolation valves (MSIVs) remain in their current position. Since the closure of the MSIVs is credited for the mitigation of several design-basis transients and accidents, such as an inadvertent opening of a steam generator relief or safety valve, steam system piping failure, or steam generator tube rupture, the staff asked the applicant, in RAI-SRP10.3-SBPA-01, to evaluate the effect that maintaining the MSIVs in an open position after a loss of electrical power would have on the mitigation of these transients and accidents. Also, the staff asked the applicant to explain whether it had analyzed the events in DCD Chapter 15, "Accident Analyses," with this MSIV fail-as-is logic.

In its response, dated July 18, 2008, the applicant clarified that the DCD statement, "On loss of electrical power the valves remain in their current position," meant that the MSIVs would not close on loss of electric power to the actuator, since the solenoids are normally deenergized and closed. This is not to imply that the MSIVs will not close, once a steamline isolation signal is generated. As discussed in DCD Section 10.3.2.2.4, each MSIV is provided with a hydraulic/pneumatic actuator. The valve actuator consists of a hydraulic cylinder with a stored energy system to provide emergency closure of the MSIV. The energy to operate the valve actuator is stored in the form of compressed nitrogen contained in one end of the actuator cylinder. The MSIVs are normally maintained in an open position by high-pressure hydraulic fluid. For emergency valve closure, normally deenergized and closed redundant solenoids for each MSIV are energized, resulting in the high-pressure hydraulic fluid being dumped to a fluid reservoir and the compressed nitrogen closing the MSIV. Additionally, Westinghouse stated that the redundant solenoids for each MSIV are powered by separate divisions from the Class 1E direct current and uninterrupted power supply systems. Energizing either solenoid for each MSIV will close the MSIV. The loss of both redundant power sources is beyond the design basis of the plant.

Based on the above explanation, the staff finds the Westinghouse response acceptable for the following reasons:

- As described above, high-pressure hydraulic fluid in the actuators maintains the MSIVs open and, therefore, a loss of power will have no effect on the MSIV position. In addition, since the solenoids are normally deenergized, a loss of power will have no effect on their ability to keep the MSIVs open.

- To close the MSIVs during an emergency, the redundant solenoids powered by separate power sources will be used to dump the high-pressure fluid from the actuators. Since the solenoids are provided by two separate sources of power, the loss of an electric power source should have no effect on the MSIV position. Therefore, the staff finds the Westinghouse response acceptable, and the concern described in RAI-SRP10.3-SBPA-01 is resolved.

(2) Table 10.3.2-1, "Main Steam Supply System Design Data," page 10.3-17:

The applicant modified the steam generator flow rates to conform to the new SPC design described in TR-86, Revision 1. In DCD Revision 15, the steamflow rate per steam generator was 3,396,535 kilograms per hour (kg/h) (7,488,000 pounds per hour (lb/h)) and the total steamflow rate was 6,793,069 kg/h (14,976,000 lb/h). In DCD Revision 16, the applicant revised the steamflow rate per steam generator to 3.40×10^6 kg/h (7.49×10^6 lb/h) and the total steamflow rate to 6.79×10^6 kg/h (14.97×10^6 lb/h). The staff reviewed these changes and determined that they are not significant and that they continue to meet all the acceptance criteria in NUREG-1793. Therefore, the staff considers these changes to be acceptable.

(3) Table 10.3.2-2, "Design Data for Main Steam Safety Valves," page 10.3-18:

The staff reviewed the applicant's revisions to the set pressures and relieving capacities of the MSSVs. Since the MSSVs are credited for the mitigation of many design-basis transients and accidents, including overpressure protection of the heatup events, such as a loss of external electrical load and a turbine trip, the staff asked the applicant, in RAI-SRP10.3-SBPA-02, to provide additional information with respect to the effects of the revised MSSV set pressures and relieving capacities on the event analysis in Chapter 15. The staff also asked whether the applicant had performed the Chapter 15 event analysis with the revised MSSV setpoints and relieving capacities.

In its response, dated July 18, 2008, Westinghouse stated that it included the revised MSSV setpoints and capacities, as shown in Table 10.3.2-2 of the DCD, in its evaluation of the limiting Chapter 15 event analyses that were provided in its response to RAI-TR29-SRSB-01. The results of the evaluation provided in the response to RAI-TR29-SRSB-01 show that the effect of the changes to the MSSV parameters meets the acceptance criteria of the limiting Chapter 15 events and that the existing analysis is bounding.

Based on its review of the Chapter 15 event analyses performed by Westinghouse, the staff finds that Westinghouse did include the revised MSSV setpoints and capacities in its evaluation of the limiting Chapter 15 event analyses. In addition, based on the results of the Chapter 15 event evaluation, the staff finds that the changes to the MSSV parameters meet the acceptance criteria of the limiting Chapter 15 events. Because Westinghouse performed the Chapter 15 event analyses with the revised MSSV setpoint pressures and relieving capacities and because the results remained within the acceptance criteria of the limiting Chapter 15 events, the staff's concern described in RAI-SRP10.3-SBPA-02 is resolved.

(4) Main Steam Piping and Instrumentation Diagrams (Safety-Related System), pages 10.3-37 and 10.3-39 (Figure 10.3.2-1, two sheets):

The applicant revised the AP1000 DCD Tier 2, Figure 10.3.2-1, to be consistent with the applicant's proposed changes to DCD Tier 1, Section 2.2.4, "Steam Generator System," described in TR-125. This change pertains to the safety-related portion of the MSSS.

During an April 1, 2009, conference call, the staff asked the applicant to provide legible DCD Tier 2 Figures 10.3.2-1 and 10.3.2-2, and to incorporate the July 3, 2008, response to RAI-SRP 3.6.1-SBPA-01 into DCD Section 10.3.1.1. Resolution of these Section 10.3 issues is being tracked as **CI-SRP10.3-SPBA-01**.

(5) Main Steam Piping and Instrumentation Diagrams (Safety-Related System), pages 10.3-37 and 10.3-39 (Figure 10.3.2-1, two sheets):

The applicant changed the system arrangement and configuration design in DCD Tier 2, Figure 10.3.2-1, to conform to TR-103.

During an April 1, 2009, conference call, the staff asked the applicant to provide legible Tier 2 Figures 10.3.2-1 and 10.3.2-2 and to incorporate the July 3, 2008, response to RAI-SRP3.6.1-SBPA-01 into DCD Section 10.3.1.1. Resolution of these Section 10.3 issues is being tracked as **CI-SRP10.3-SPBA-01**.

(6) Main Steam System Diagram, page 10.3-41 (Figure 10.3.2-2):

The applicant modified the MSSS arrangement to conform to the new SPC design, as proposed in TR-86, Revision 1. The applicant's changes to subsections, tables, and figures of the DCD support the specifics of the new design. The staff reviewed these changes and finds that they are modifications to the system arrangement and configuration design. The staff finds that these changes will have no impact on the ability of the MSSS to supply steam from the steam generator to the main turbine-generator system. The staff finds that the MSSS will continue to meet all of the acceptance criteria in NUREG-1793 and, therefore, the changes are acceptable.

(7) a) Section 10.3.1.1, "Safety Design Basis," Page 10.3-3:

The applicant added the turbine bypass valve and also changed the moisture separator reheater stop valves to moisture separator reheater 2nd stage steam isolation valves in the list of valves credited in a single failure analysis. These valves are credited in the analysis to mitigate the event for those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event. These two changes conform to the applicant's response to RAI-SRP3.6.1-SBPA-01, which was found acceptable in SER Section 3.6.1.

b) Tier 1 Table 2.2.4-3, "Components which Provide Backup Isolation of the Steam Generator System," Page 2.2.4-15:

The applicant added two moisture separator reheater 2nd stage steam isolation valves to the list of components which provide backup isolation of the SGS and deleted other components. The staff reviewed this design change and determined that it was made to be consistent with the change made in a) above. Therefore, the staff finds the change to be acceptable.

c) Section 10.3.4.2, "In-service Testing," Page 10.3-12:

The applicant revised the scope of the in-service testing (IST) program for the AP1000 reactor to replace the Moisture Separator Reheater Steam Supply Control Valves, MSS-PL-V016A & B and MSS-PL-V017A & B, with the Moisture Separator Reheater 2nd Stage Steam Isolation Valves, MSS-PL-V015A & B, in response to the design change described in a) above. The staff reviewed the revised IST program description for consistency with the design change. MSS-PL-V015A & B have been included in AP1000 DCD Tier 2, Table 3.9-16, because the design change will have those valves perform a backup isolation function for the safety-related MSIVs in the AP1000 reactor design rather than MSS-PL-V016A & B and MSS-PL-V017A & B. MSS-PL-V015A & B are non-safety related valves (without a specific safety-related leakage limitation) that are outside the scope of the IST requirements specified in 10 CFR 50.55a, and will be included in the IST program for the AP1000 reactor to augment their performance capability. Based on its review, the staff finds the revision to the IST program scope to be consistent with the design change described in a) above.

(8) Piping Material Changes to Section 10.3.2.2.1, “Main Steam Piping,” Page 10.3-5; Table 10.3.2-3, “Description of Main Steam and Main Feedwater Piping,” Page 10.3-19; Main Steam Piping and Instrumentation Diagrams (Safety-Related System) and Page 10.3-37 (Figure 10.3.2-1, “Main Steam Piping and Instrumentation Diagram (Safety-Related System) – Sheet 1 of 2):

The applicant changed the material used for the main steam piping and segments of the main feedwater line to low alloy steel to facilitate a design life of 60 years with respect to minimizing the effects of erosion/corrosion. In the certified design, carbon steel is the main steam piping material for some portions. The changes proposed in Revision 17 make P11 material (nominally 1.25 percent chromium and 0.5 percent molybdenum) the only material for main steam piping. The staff finds this material is acceptable because testing and operating experience have shown P11 is resistant to flow-accelerated corrosion (sometimes called erosion-corrosion) in main steam piping, including wet steam. Current industry guidance (EPRI NSAC-202L) allows P11 main steam components to be excluded from flow-accelerated corrosion inspection programs due to the flow accelerated corrosion resistance imparted by the chromium and, to a lesser extent, molybdenum.

(9) Section 10.3.3, “Safety Evaluation,” Page 10.3-10:

The applicant changed from inline main steam line radiation monitors to adjacent-to-line radiation monitors.

The applicant made the change to section 10.3.3 to be consistent with the detailed monitor description provided in DCD section 11.5.2.3.1. DCD Section 11.5.2.3.1 has not changed from the DCD, Revision 15 description of these monitors as “…adjacent to the steam lines”. The staff concludes that both DCD sections are now consistent and that the change to 10.3 is acceptable. The staff provides additional evaluation of the main steam line monitors in SER section 11.5.2.4.

(10) Table 10.3.2-2, “Design Data for Main Steam Safety Valves,” Page 10.3-18:

In Table 10.3-2-2, the applicant changed the size of main steam safety valve and added clarifying text. The main steam safety valves are designed to ASME Code Section III, Class 2, seismic Category I. Based on the system’s accumulation pressure of 3 percent, per Subsection NC-7512 of ASME Code, Section III, Division 1, 1989 Edition, Subsection NC, Class 2 components, the applicant increased the relieving capacity of main steam safety valves. The changes were made to ensure that the main steam safety valve design meets the requirements and conforms to the ASME code. The staff finds the changes acceptable.

(11) Table 10.3.2-4, “Main Steam Branch Piping (2.5-Inch and Larger) Downstream of MSIV,” Page 10.3-20:

The applicant changed, in DCD Table 10.3.2-4: the size of the shutoff valves for the turbine bypass lines to the condenser from 30.5 cm (12 inch) to 40.6 cm (16 inch), the size of the shutoff valves for the reheating steam to moisture separator reheater lines from 30.5 cm (12 inch) to 25.4 cm (10 inch), and the numerical value for the maximum steam flow rate for these lines. The description of the shutoff valve and number of lines under the description column was also changed. Further, the size of the shutoff valve for the main steam supply to auxiliary steam system line was changed from 15.2 cm (6 inch) to 25.4 cm (10 inch).

As reflected in Table 10.3.2-4, the applicant made changes to the main steam branch piping, in order to meet the analyzed closure time for the MSIV backup isolation valves.

, The applicant made changes to the main steam shutoff valves In Table 10.3.2-4, to support the change in the turbine generator design and to optimize the auxiliary steam supply system. The staff reviewed these design changes and determined that they are bounded by existing safety analysis because the shutoff valve closure times remain unchanged. The design will continue to meet all acceptance criteria in NUREG-1793. The staff finds the changes are acceptable.

10.3.1.3 <u>Conclusion</u>

In NUREG-1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed the applicant’s proposed changes to the AP1000 MSSS as documented in AP1000 DCD, Revisions 16 and 17. The staff finds that the applicant’s proposed changes do not affect the ability of the AP1000 MSSS to meet the applicable acceptance criteria in SRP Section 10.3. The staff also finds that the applicant properly incorporated the design changes into the appropriate sections of AP1000 DCD, Revisions 16 and 17. Because the AP1000 MSSS design continues to meet all of the applicable acceptance criteria and the changes are properly documented in the updated AP1000 DCD, the staff finds that all of the changes to the AP1000 MSSS are acceptable.

10.4 <u>Other Features</u>

10.4.1 Main Condensers

<u>10.4.1.1 Summary of Technical Information</u>

In NUREG-1793, “Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design,” the staff approved Section 10.4.1, “Main Condenser,” of the AP1000 design control document (DCD), Revision 15. In AP1000 DCD, Revision 17, the applicant proposed to make the following changes to Section 10.4.1 of the DCD, Revision 15.

In DCD Section 10.4.1.2, “System Description,” Paragraph 2, the applicant revised the condenser tube material providing an option to the COL applicant to substitute “stainless steel” tubes for “titanium” tubes for fresh water cooled plants. The revised description reads as, “…..The condenser is equipped with titanium <u>or stainless</u> steel tubes. The titanium material provides good corrosion and erosion resisting properties. <u>Fresh water cooled plants do not require the high level corrosion and erosion resistance provided by titanium; therefore, 304L, 316L, 904L, or AL-6X may be substituted if desired.</u>” The revisions are indicated by the underlined text. The applicant added a corresponding note to Table 10.4.1-1, “Main Condenser Design Data.” In addition, a second note added to Table 10.4.1-1 states that if one of the alternate tube materials (i.e., stainless steel) is used, the tubesheet will be carbon steel material with a cladding of the same material as the tubes. The certified design specified titanium or titanium-clad carbon steel as the tubesheet material.

<u>10.4.1.2 Evaluation</u>

The staff reviewed the changes to the AP1000 DCD, Revision 15, Section 10.4.1 that were identified in DCD, Revision 17. The regulatory basis for AP1000 DCD, Section 10.4.1, is documented in the NUREG-1793. The staff has reviewed the proposed changes to DCD Section 10.4.1 against the applicable acceptance criteria of Standard Review Plan (SRP) Section 10.4.1, “Main Condensers.”

The changes identified above are related to the material of the condenser tubes. Several stainless steel alloys (304L, 316L, 904L, and AL-6X) were added as alternatives to titanium condenser tube material for plants cooled by fresh water. The staff finds the use of stainless steel materials is acceptable because the corrosion of stainless steel in cooling waters is strongly related to the chloride content. Operating experience has shown that the stainless steels proposed by the applicant are suitable for condenser tubes in fresh water applications. For example, EPRI characterizes the corrosion resistance of these stainless steels as very good to excellent in fresh water (EPRI TR-102922, “High-Reliability Condenser Application Study,” Final Report, November 1993). The corresponding change to allow the tubesheet to be carbon steel with a cladding of the same stainless steel as the tube material is also acceptable based on the operating experience referenced above.

<u>10.4.1.3 Conclusion</u>

In NUREG 1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that Westinghouse’s application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed Section 10.4.1, “Main Condensers,” as documented in AP1000 DCD, Revision 17. On the basis of its review, the staff finds that the design changes have been adequately incorporated into the appropriate sections of AP1000 DCD, Revision 17. The staff also finds, based on operating experience with stainless steel condenser tubes, that the main condenser continues to meet all acceptance criteria as documented in NUREG 1793, and are therefore considered to be acceptable.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Summary of Technical Information

In NUREG-1793, the staff approved Section 10.4.2, "Main Condenser Evacuation System," of the AP1000 DCD, Revision 15. In AP1000 DCD, Revision 17, the applicant revised Sections 10.4.2.2.1, "General Description," and 10.4.2.2.2, "Component Description," to identify the circulating water system (CWS) as conceptual design information (CDI).

10.4.2.2 Evaluation

The staff reviewed all of the changes to the AP1000 DCD, Revision 15, Section 10.4.2, that were identified in the AP1000 DCD, Revision 17. The staff did not re-review descriptions and evaluations of Section 10.4.2 that were previously approved and that are not affected by the new changes.

The specific criterion that applies to the Main Condenser Evacuation System related changes is 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

NUREG-1793 contains the regulatory basis for Section 10.4.2 of the AP1000 DCD. The staff has reviewed the proposed changes to DCD Section 10.4.2 against the applicable acceptance criteria in SRP Section 10.4.2.

The only change the applicant proposed to the AP1000 DCD, Section 10.4.2, was to identify the CWS as CDI. The staff discusses the issue of identifying the CWS as CDI in Section 10.4.5 of this report. Since the changes made to DCD Sections 10.4.2.2.1 and 10.4.2.2.2 conform to the changes made to DCD Section 10.4.5 and do not adversely affect the main condenser evacuation system, the staff finds these changes to be acceptable.

10.4.2.3 Conclusion

In NUREG-1793 and its Supplement 1, the staff documented its conclusion that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed Section 10.4.2 as documented in the AP1000 DCD, Revision 17. The staff finds no changes except the two conforming changes identified above. On the basis of its review, the staff finds that the main condenser evacuation system continues to meet all of the acceptance criteria in NUREG-1793, and these changes are, therefore, acceptable.

10.4.3 Turbine Gland Seal System

10.4.3.1 Summary of Technical Information

In NUREG-1793, the staff approved the AP1000 DCD, Revision 15, Section 10.4.3, "Gland Seal System." In the AP1000 DCD, Revision 17, the applicant proposed changes to Section 10.4.3 of the DCD, Revisions 14 and 15.

In the AP1000 DCD, Section 10.4.3, the applicant made the following changes, which reflect the new single turbine-generator design (i.e., alternative SPC design) that is proposed in TR-86, Revision 1:

(1) Section 10.4.3.2.2, "System Operation," of the DCD, Revision 16:

The AP1000 DCD, Revision 15, Section 10.4.3.2.2, stated that the sealing steam to the turbine shaft seals is supplied from either the auxiliary steam system or from the main steam system extracted ahead of the high-pressure turbine <u>throttle</u> valve. In DCD Revision 17, the applicant revised Section 10.4.3.2.2 to refer to the "high-pressure turbine control valve."

In addition, DCD Section 10.4.3.2.2, Revision 15, stated that, at times other than initial startup, turbine-generator sealing steam is supplied from the auxiliary steam system or from main steam. In DCD, Revision 17, the applicant modified paragraph 3 on page 10.4-7 to add "the MSV (main steam stop valve) and CV (control valve) gland steam leak-off" as an additional source of steam to the turbine gland seals.

(2) Section 10.4.3.5, "Instrumentation Applications," of the DCD, Revision 17:

The applicant removed the following sentence: "Pressure control valves are used to provide appropriate pressures to operate both the low and high pressure turbine steam seals."

10.4.3.2 <u>Evaluation</u>

The staff reviewed all of the changes to the AP1000 DCD, Revision 15, Section 10.4.3, that were identified in the DCD, Revision 17. The staff did not review descriptions and evaluations of Section 10.4.3 that were previously approved and that are not affected by the new changes.

NUREG-1793 contains the regulatory basis for Section 10.4.3 of the AP1000 DCD. The staff has reviewed the proposed changes to the AP1000 DCD, Section 10.4.3, against the applicable acceptance criteria of SRP Section 10.4.3, "Turbine Gland Sealing System."

The specific criterion that applies to the Turbine Gland Seal System related changes is 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

The staff finds that the changes to DCD Section 10.4.3.2.2 associated with specifying a high-pressure turbine control valve and the addition of sealing steam supply from MSV and CV gland steam leakoff are conforming changes to the new design, in accordance with TR-86, Revision 1, and do not affect the staff's conclusion in NUREG-1793 that the gland seal system design meets the requirements of GDC 60, "Control of Releases of Radioactive Materials to the Environment," with respect to the design features in place to control releases of radioactive materials to the environment. Therefore, the staff finds these changes acceptable.

However, with respect to the removal of the pressure control valves from DCD Section 10.4.3.5, "Instrumentation Application," the applicant did not provide a basis for this change. Therefore, in RAI-SRP10.4.3-SBPA-01, the staff asked the applicant to explain and justify this deletion of the pressure-regulating valves.

In response to RAI-SRP10.4.3-SBPA-01, in its letter dated June 20, 2008, Westinghouse stated that the AP1000 gland seal system uses pressure-regulating valves to control steam pressure to the turbine glands. In its previous design, as described in the DCD, Revision 15, the high-pressure and low-pressure turbine glands used steam at different pressures and therefore had their own pressure-regulating valves to deliver their respective pressures. In Revision 17 of the DCD, however, Westinghouse changed its design to a single-pressure system, in which the high- and low-pressure turbine glands use the same steam pressure from a common gland seal steam supply header. Figure 10.4.3-1 of the DCD, Revision 17, contains the diagram depicting the gland seal steam piping and instrumentation. The gland seal steam header is supplied with steam from both the auxiliary steam and main steam systems, and the above-cited pressure-regulating valves are located in each of these systems upstream of the header. Based on the above discussion and a review of Figure 10.4.3-1, the staff finds the elimination of the gland seal steam dual-pressure system acceptable, since it is the new Westinghouse design and does not affect any safety-related systems or equipment. Therefore, the staff's concern described in RAI-SRP10.4.3-SBPA-01 is resolved.

10.4.3.3 Conclusion

In NUREG-1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed Section 10.4.3 as documented in the AP1000 DCD, Revision 17. The staff finds that the changes with respect to specifying a high-pressure turbine control valve, the addition of seal steam supply from MSV and CV gland steam leakoff, and other changes to the gland seal system design proposed in TR-86, Revision 1, do not affect the staff's conclusion in NUREG-1793 that the gland seal system design meets the requirements of GDC 60, with respect to the design features in place to control releases of radioactive materials to the environment. The proposed changes do not adversely affect the AP1000 turbine gland seal steam system.

10.4.4 Turbine Bypass System

10.4.4.1 Summary of Technical Information

In NUREG-1793, "Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design," the staff approved Section 10.4.4, "Turbine Bypass System," of the AP1000 design control document (DCD), Revision 15.

In AP1000 DCD, Revision 17, the applicant proposed a change in Section 10.4.4.2.2, "Component Description," to clarify the manual use of the bypass valves during cooldown. The revised sentence reads: "…the low T_{avg} block can be manually bypassed for ~~one of~~ the bypass valves that are designated as cooldown valves to allow operation during plant cooldown." The addition is indicated by underlined text.

10.4.4.2 Evaluation

The staff reviewed the changes to Section 10.4.4 that were identified in the AP1000 DCD Revision 17. The specific criterion that applies to the change is 10 CFR 52.63(a)(1)(vii), in that the proposed change contribute to increased standardization of the certification information.

The regulatory basis for AP1000 DCD, Section 10.4.4, is documented in the NUREG-1793. The staff reviewed the proposed changes to DCD Section 10.4.4 against the applicable acceptance criteria of Standard Review Plan (SRP) Section 10.4.4. The acceptability of the system design is based on meeting the following GDC as described in the SRP:

- GDC 4, as it relates to the system being designated such that a failure of the system (due to a pipe break or system malfunction) does not adversely affect safety-related systems or components

- GDC 34, as it relates to the ability to use the turbine bypass system for shutting down the plant during normal operations by removing residual heat without using the turbine generator

The change proposed by the applicant is considered a clarification and does not alter the ability of the system to manually bypass a T_{avg} block and allow operation of the bypass valves during plant cooldown. Therefore, the change is considered acceptable.

10.4.4.3 Conclusion

In NUREG 1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that Westinghouse's application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed Section 10.4.4, 'Turbine Bypass System," as documented in AP1000 DCD, Revision 17. On the basis of its review, the staff finds the turbine bypass system continues to meet all acceptance criteria as documented in NUREG 1793, and is therefore considered to be acceptable.

10.4.5 Circulating Water System

10.4.5.1 Summary of Technical Information

In NUREG-1793, the staff approved Section 10.4.5, "Circulating Water System," of the AP1000 DCD, Revision 15. In AP1000 DCD, Revision 17, the applicant proposed the following changes to Section 10.4.3 of DCD.

In the AP1000 DCD, Revision 17, Section 10.4.5, the applicant identified CDI items related to the alternative SPC design proposed in TR-86, Revision 1. Additionally, as part of identifying the CDI information, the applicant revised Section 10.4.5 to include makeup water as an additional source to the CWS by stating the following:

> The CWS and/or makeup water from the raw water system supplies cooling water to the turbine building closed cooling water system (TCS) heat exchangers

and the condenser vacuum pump seal water heat exchangers under varying conditions of power plant loading and design weather conditions.

The underlined text indicates the revisions.

10.4.5.2 Evaluation

The staff reviewed the proposed changes to the CWS in the AP1000 DCD, Revision 17. The staff did not review descriptions and evaluations of Section 10.4.5 that were previously approved and that are not affected by the new changes. The specific criterion that applies to the changes is 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

NUREG-1793 contains the regulatory basis for Section 10.4.5 of the AP1000 DCD. The staff has reviewed the proposed changes to DCD Section 10.4.5 against the applicable acceptance criteria of SRP Section 10.4.5, "Circulating Water System," and other applicable criteria.

Since the CWS system configuration and its components, such as circulating water pumps, cooling tower or heat sink, and piping and valves, are plant-specific items, the applicant identified these as CDI items. Further, the addition of makeup water to the CWS for the supply of cooling water to the turbine control system heat exchangers and the condenser vacuum pump seal water heat exchangers are plant-specific CDI items.

Therefore, the staff finds that the addition of makeup water and the identification of CDI items are changes to conform to the new design, in accordance with TR-86, Revision 1, and do not affect the staff's conclusion in NUREG-1793 that the CWS design meets the requirements of GDC 4 with respect to the effects of discharging water that may result from a failure of a component or piping in the CWS. Therefore, the staff finds these changes to be acceptable.

10.4.5.3 Conclusion

In NUREG-1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed Section 10.4.5, as documented in AP1000 DCD, Revision 17. The staff finds that the addition of the makeup water system and the identification of the CDI items are acceptable, as they relate to the new design proposed in TR-86, Revision 1. Further, these revisions to Section 10.4.5 of the DCD, Revision 17, do not adversely affect the ability of the CWS to meet the requirements of GDC 4. On the basis of its review, the staff finds that the CSW continues to meet all of the acceptance criteria in NUREG-1793 and is, therefore, acceptable.

10.4.7 Condensate and Feedwater System

10.4.7.1 Summary of Technical Information

In NUREG-1793 the staff approved Section 10.4.7, “Condensate and Feedwater System,” of the AP1000 DCD, Revision 15. In the AP1000 DCD, Revision 17 the applicant proposed changes to Section 10.4.7.

The applicant proposed the following four technical changes to Revision 15 of the AP1000 DCD, three of which are supported by information contained in Westinghouse TRs:

(1) In Revision 17 to the AP1000 DCD, pages 10.4-21, 10.4-22, 10.4-26, and drawing page 10.4-71 (Figure 10.4.7-1, Sheet 3 of 4), the applicant proposed changing the number of high-pressure feedwater heater stages from one to two. The AP1000 DCD, Revision 15, designates the one high-pressure feedwater heater stage as feedwater heater number 6, with the stage consisting of two parallel feedwater heaters, numbers 6A and 6B. The AP1000 DCD, Revision 17, designates the additional stage feedwater heater number 7, with the stage consisting of two parallel feedwater heaters, numbers 7A and 7B. TR-86, Revision 1, documents the basis for this change.

(2) In the AP1000 DCD, Revision 17, page 10.4-25, the applicant changed text in the first and second paragraphs under the title “Low-Pressure Feedwater Heaters.” The current text reads as follows:

> Except for the No. 1 feedwater heaters, the closed low-pressure feedwater heaters have integral drain coolers, and their shell side drains cascade to the next lower stage feedwater heater. The drains from the No. 1 heaters are dumped to their respective condenser shell.
>
> A drain line from each heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The revised text reads as follows:

> The closed low-pressure feedwater heaters use drain coolers. The cascaded drains from the heaters are dumped to their respective condenser shell.
>
> A drain line from the heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

TR-86, Revision 1, documents the basis for this change. The applicant also incorporated this change in the AP1000 DCD, Revision 17, on drawing page 10.4-69 (Figure 10.4.7-1, Sheet 2 of 4), to show that the number 1 and number 2 feedwater heater drains dump into their respective condenser shells.

(3) In the AP1000 DCD, Revision 17, on page 10.4-73 (Figure 10.4.7-1, Sheet 4 of 4), the applicant proposed eliminating pressure transmitters PT043, PT044, and PT045, and pressure instrument controllers PIC043, PIC044 and PIC045, and replacing them with PT042 and PC042. TR-103, Revision 2, documents this change.

(4) In the AP1000 DCD, Revision 17, on pages10.4-69 and 10.4-71 (Figure 10.4.7-1, Sheets 2 and 3), the applicant apparently made a change to the arrangement of the deaerator feedwater heater and its associated storage tank.

10.4.7.2 Evaluation

The staff reviewed all changes to the condensate and feedwater system (CFS) in the AP1000 DCD, Revision 17. The staff did not re-review descriptions and evaluations of Section 10.4.7 that were previously approved and are not affected by the new changes. The specific criteria that apply to the Condensate and Feedwater System related changes include 10 CFR 52.63(a)(1)(vi) in that the changes substantially increases overall safety, reliability, or security of facility design, construction, or operation, and the direct and indirect costs of implementation of the rule change are justified in view of this increased safety, reliability, or security, and 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

NUREG-1793 contains the regulatory basis for Section 10.4.7 of the AP1000 DCD. The staff has reviewed the proposed changes to DCD Section 10.4.7 against the applicable acceptance criteria of SRP Section 10.4.7, “Condensate and Feedwater System.” The following evaluation discusses the results of the staff’s review.

10.4.7.2.1 Condensate and Feedwater System—Addition of High-Pressure Feedwater Heater Stage 7

In TR-86, Revision 1, Section 1, the applicant stated that an alternative SPC design was presented in Revision 0 of TR-86 as DCD Chapter 10A, and that all standard AP1000 units built will now employ a single turbine-generator and steam-cycle design. The applicant proposed incorporating changes from DCD Chapter 10A as a single design for AP1000 and stated that one of the significant differences between the reference design and the alternative new design of the turbine-generator set is the addition of a seventh-stage feedwater heater. Because the alternative design of the turbine-generator set uses a seventh-stage high-pressure feedwater heater in its feedwater system design, and because the addition of the seventh-stage heater has no effect on CFS compliance with GDC 2, “Design Bases for Protection against Natural Phenomena,” GDC 4, GDC 44, “Cooling Water,” GDC 45, “Inspection of Cooling Water System,” and GDC 46, “Testing of Cooling Water System,” the staff finds the addition of the second high-pressure feedwater heater to the AP1000 CFS design acceptable. The staff also finds that the addition of the seventh-stage heater does not result in a change to the CFS compliance with SRP Section 10.4.7 in NUREG-1793.

10.4.7.2.2 Condensate and Feedwater System, Low-Pressure Feedwater Heater Stages 1 and 2 Drain to Their Respective Condensers

In TR-86, Revision 1, on page 52, the applicant proposed a design change for low-pressure feedwater heater stages 1 and 2 drains to dump directly into their respective condenser shells. This design change is part of the alternative SPC design described in Revision 0 of TR-86 as DCD Chapter 10A. Also, on page 60 of TR-86, Revision 1, the applicant proposed a similar change to DCD Figure 10.4.7-1 (Sheet 2 of 4), which has been changed schematically to show that the drains from low-pressure feedwater heaters 1A, 1B, 1C, 2A, 2B, and 2C dump into the respective condenser shells A, B, and C. The low-pressure feedwater heater stage 2 drain no longer cascades into feedwater heater stage 1. Because the alternative design of the turbine-generator set uses a different drainpath for the No. 2 low-pressure feedwater heater stage, which does not affect the safety-related functions of the CFS or its compliance with GDC 2, 4, 44, 45, and 46, the staff finds this design change to the AP1000 CFS acceptable. The staff also finds that the change to the heater drain system does not result in a change to the CFS compliance with SRP Section 10.4.7 in NUREG-1793.

10.4.7.2.3 Condensate and Feedwater System Pressure Transmitters PT043, PT044, and PT045, and Pressure Instrument Controllers PIC043, PIC044, and PIC045 Replaced with PT042 and PC042

In TR-103, Revision 2, on page 7, the applicant proposed eliminating the control function shown in Figure 10.4.7-1 (Sheet 4 of 4) for PT-043–45, because the startup feedwater header pressure is no longer an input to the startup feedwater control system. In TR-103, the applicant further stated that all three pressure transmitters are no longer necessary, since they do not have a control function and pressure transmitters PT-044 and PT-045 have been deleted. Additionally, the applicant has revised Note 4 to reflect the updated control logic diagram APP-PLS-J1-143 and has deleted the statement in the note that mentions startup feedwater header pressure as an input to the control system. The applicant also made a change in Note 3 to indicate that control logic diagram APP-PLS-J1-114 has been updated and is now APP-PLS-J1-144.

Because the startup feedwater header pressure signal no longer provides input to the startup feedwater control system, and the new control logic does not affect the CFS compliance with GDC 2, 4, 44, 45, and 46, the staff finds this design change to the AP1000 CFS acceptable. Section 7.7.1.5 of this safety evaluation report reviews the acceptability of instrumentation and controls changes related to AP1000 DCD Sections 7.7.1.8.1 (Feedwater Control) and 7.7.1.8.2 (Startup Feedwater Control).

10.4.7.2.4 Figure 10.4.7-1 (Sheets 2 and 3) Revised To Show the ME 05 “Deaerator Feedwater Heater and Deaerator Storage Tank” as a Single Component

The approved DCD shows the deaerator and the deaerator storage tank as separate components. However, the AP1000 DCD, Revision 16, Figure 10.4.7-1 (Sheets 2 and 3), shows the deaerator feedwater heater and the deaerator storage tank as a single component. Furthermore, Section 10.4.7.2.2, “Component Description,” of the DCD describes the deaerator as “a tray type, horizontal shell, direct contact heater located on top of a horizontal storage tank.” Since the design of the deaerator and the deaerator storage tank in the AP1000 DCD, Revision 16, differs from the approved design and from the component description provided in the DCD, the staff, in RA-SRP10.4.7-SBPA-01, dated April 28, 2008, asked the applicant to explain why the design change is acceptable.

In its response, dated June 20, 2008, the applicant stated that there was no change to the function of the deaerator or the feedwater and condensate systems, and the confusion was a result of the various descriptions and pictorial representations of the deaerator used throughout the DCD. A more consistent representation of the deaerator in the DCD would have likely prevented the confusion. The deaerator vendor changed the previous vendor’s design, which used a deaerator storage tank with the deaerating heater mounted on top of the tank. The latest vendor’s standard design is functionally the same, but the deaerating heater is mounted inside the deaerator storage tank.

The applicant further stated that the differences between the two vendors’ deaerator designs do not have any effect on the design or function of the feedwater and condensate systems. The applicant changed DCD Figure 10.4.7-1 (Sheets 2 and 3), as well as the text in DCD Section 10.4.7.2.2, to more accurately reflect the current vendor's deaerator.

In evaluating the applicant's response, the staff notes that the applicant indicated that the deaerator vendor had changed and that, in the new vendor's design, the deaerator heater is mounted inside the deaerator storage tank, as opposed to being located on top of the tank, as was the case in the DCD revisions before Revision 16. However, while the new design is shown in revised Figure 10.4.7-1, the deaerator description in Section 10.4.7.2.2 continues to describe the dearator as "a tray type horizontal shell, direct contact heater located on top of a horizontal storage tank." The deareator described in Section 10.4.7.2.2 of the DCD, and that shown in Figure 10.4.7-1, are not consistent, despite the applicant's claim in its response that it changed the text in DCD Section 10.4.7.2.2 to more accurately reflect the current vendor's deaerator. The staff found the DCD information on the deaerator to be inconsistent and the applicant's response to be insufficient, since the response contains an inaccuracy regarding the text in Section 10.4.7.2.2. In Revision 17 of the DCD, Section 10.4.7.2.2, Westinghouse revised the text that describes the Deaerator to reflect what is shown in Figure 10.4.7-1 of the DCD. On the basis of its review, the staff finds RAI-SRP 10.4.7-SBPA-01 to be resolved.

10.4.7.2 Conclusion

The staff reviewed the applicant's proposed changes to the CFS as documented in the AP1000 DCD, Revision 17. The staff finds that the applicant's proposed changes do not affect the ability of the AP1000 CFS to meet the applicable acceptance criteria. The staff also finds that the applicant properly incorporated the design changes into the appropriate sections of the AP1000 DCD, Revision 17. Because the AP1000 CFS design continues to meet all of the applicable acceptance criteria and the changes are properly documented in the updated AP1000 DCD, the staff finds that all of the changes to the AP1000 CFS are acceptable.

10.4.8 Steam Generator Blowdown System

10.4.8.1 <u>Summary of Technical Information</u>

The staff approved Section 10.4.8, "Steam Generator Blowdown System," of the AP1000 DCD, Revision 15, in the certified design. In the AP1000 DCD, Revision 17, the applicant proposed changes to Section 10.4.8 of the certified design.

- In DCD Subsection 10.4.8.2.2, the system flow rates were increased by approximately 8 to 9 percent. In a letter dated July 30, 2009 the applicant explained that the flow rates were changed in order to reflect updated system design calculations. In addition, the words, "at standard conditions" were added after the flow rates.
- Three wording corrections were made for consistency with other parts of the DCD.
- A note was added to Figure 10.4.8-1. The note identifies the drawing as a functional arrangement that could have different internal details due to procurement requirements.

10.4.8.2 <u>Evaluation</u>

The staff reviewed the changes to the Steam Generator Blowdown System identified in Section 10.4.8 of the AP1000 DCD, Revision 17. The staff did not review descriptions and evaluations of Section 10.4.8 that were previously approved and that are not affected by the new changes. The specific criteria that apply to the Steam and Generator Blowdown System related changes include 10 CFR 52.63(a)(1)(vi) in that the changes substantially increases overall safety, reliability, or security of facility design, construction, or operation, and the direct and indirect costs of implementation of the rule change are justified in view of this increased safety, reliability, or security, and 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

NUREG-1793 contains the regulatory basis for Section 10.4.8 of the AP1000 DCD. The staff reviewed the proposed changes in Revision 17 against the applicable acceptance criteria of SRP Section 10.4.8, “Steam Generator Blowdown System,” and other applicable criteria.

The staff finds the changes in flow rate values acceptable because they do not affect the amount of blowdown as a percentage of steam flow. Hence, the updated flow rates support the level of secondary-side water purification in the certified AP1000 design. Adding the phrase, “at standard conditions” is acceptable because it provides clarification to the flow-rate values.

The other wording changes were made for consistency with the design as documented in other parts of the DCD and are, thus, acceptable. The note added to Figure 10.4.8-1 is acceptable because it clarifies that there is flexibility in the as-built system without affecting the system functionality.

10.4.8.3 Conclusion

In NUREG-1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed the applicant’s proposed changes to the AP1000 steam generator blowdown system, as documented in the AP1000 DCD, Revision 17. The staff finds that the applicant’s proposed changes do not affect the ability of the steam generator blowdown system to meet the applicable acceptance criteria. Therefore, the staff finds that the proposed changes to the AP1000 DCD, Section 10.4.8, are acceptable.

10.4.10 Auxiliary Steam System

The staff approved Section 10.4.10, “Auxiliary Steam System,” of the AP1000 DCD, Revision 15, in the certified design. In the AP1000 DCD, Revision 17, the applicant proposed the following change to Section 10.4.10 of the certified design.

The applicant replaced the oil-fired boiler with an electric boiler. TR-114, “AP1000 Auxiliary Boiler Sizing and Design” (APP-GW-GLR-114), dated June 14, 2007, documents the basis for this change. The applicant deleted detailed design information for the oil-fired boiler and proposed some changes throughout Section 10.4.10 to reflect the changes addressed in TR-114.

The staff confirmed that all other changes in DCD Section 10.4.10 are editorial and do not require an evaluation.

10.4.10.1 Evaluation

The staff reviewed all changes identified in AP1000 DCD, Revision 17. The staff did not review descriptions and evaluations of the auxiliary steam system in the AP1000 DCD, Revision 15, that were previously approved and that are not affected by the new changes. All technical changes in the DCD are supported by information presented in Westinghouse TRs. The specific criteria that apply to the Auxiliary Steam System related changes include 10 CFR 52.63(a)(1)(vi) in that the changes substantially increases overall safety, reliability, or security of facility design, construction, or operation, and the direct and indirect costs of implementation of the rule change are justified in view of this increased safety, reliability, or security, and 10 CFR 52.63(a)(1)(vii), in that the proposed changes contribute to increased standardization of the certification information.

NUREG-1793 contains the regulatory basis for Section 10.4.10 of the AP1000 DCD. In its previous evaluations of this section, the staff found that the current SRP does not include a section specifically addressing the auxiliary steam system. The staff has determined that the acceptability of this system will be based on meeting the requirements of GDC 4. In other words, failure of the auxiliary steam system, as a result of a pipe break or malfunction of the system, should not adversely affect safety-related SSCs. The staff has reviewed the proposed changes to DCD Section 10.4.10 and discusses the results below.

The applicant replaced the oil-fired boiler with an electric boiler and submitted TR-114 to address the basis for this change. The applicant proposed a series of changes to DCD Section 10.4.10 to be consistent with the new electric boiler. These changes include the following:

- The applicant added text to DCD Section 10.4.10.1.2 to indicate that auxiliary steam supplements the main steam system during startup. This change provides additional information on system operation, has no impact on the auxiliary steam system, and is, therefore, acceptable.

- The applicant deleted reference to "oil-fired boiler" and replaced it with "electric package boiler" in DCD Section 10.4.10.2.2. This is a conforming change to reflect the design change and is, therefore, acceptable.

- The applicant changed the nominal net output capacity from "at least 110,000 pounds per hour (49,900 kilograms per hour)" to "approximately 100,000 pounds per hour (45,360 kilograms per hour)" in DCD Section 10.4.10.2.2. This change has no impact on any safety-related SSC and, therefore, is acceptable.

- The applicant deleted the component description for the auxiliary boiler fuel-oil components from DCD Section 10.4.10.2.2. This is a conforming change to reflect the design change and, therefore, is acceptable.

10.4.10.2 Conclusion

In NUREG-1793 and its Supplement 1, the staff documented its conclusions that the AP1000 design and DCD (up to and including Revision 15 of the DCD) were acceptable and that the Westinghouse application for design certification met the requirements of Subpart B to 10 CFR Part 52 that are applicable and technically relevant to the AP1000 standard plant design.

The staff reviewed the applicant's proposed changes to the AP1000 auxiliary steam system, as documented in the AP1000 DCD, Revision 17, against GDC 4. The staff finds that the applicant's proposed changes do not affect the ability of the auxiliary steam system to meet the applicable acceptance criteria. The staff also finds that the applicant properly incorporated the design changes into the appropriate sections of the AP1000 DCD, Revision 17. The staff concludes that the AP1000 auxiliary steam system continues to meet all applicable acceptance criteria, and the proposed changes are properly documented in the updated AP1000 DCD; therefore, the staff finds that the proposed changes to the AP1000 DCD, Section 10.4.10, are acceptable.