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Subject: **Response to Portion of NRC Request for Additional Information Letter No. 76 Related to ESBWR Design Certification Application - Instrumentation and Control - RAI Numbers 7.1-43, 7.2-33, 7.2-34, 7.2-36, 7.2-41 through 7.2-49, 7.3-3, through 7.3-6, 7.3-8, 7.3-9, 7.7-2, 7.7-5, and 7.9-15**

Enclosure 1 contains GE's response to the subject NRC RAIs transmitted via the Reference 1 letter.

If you have any questions or require additional information regarding the information provided here, please contact me.

Sincerely,

Kathy Sedney for

James C. Kinsey
Project Manager, ESBWR Licensing

D068

Reference:

1. MFN 06-388, Letter from U.S. Nuclear Regulatory Commission to David Hinds, *Request for Additional Information Letter No. 76 Related to ESBWR Design Certification Application*, October 11, 2006

Enclosures:

1. MFN 07-015 Response to Portion of NRC Request for Additional Information Letter No. 76 Related to ESBWR Design Certification Application - Instrumentation and Control - RAI Numbers 7.1-43, 7.2-33, 7.2-34, 7.2-36, 7.2-41 through 7.2-49, 7.3-3, through 7.3-6, 7.3-8, 7.3-9, 7.7-2, 7.7-5, and 7.9-15

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Enclosure 1

MFN 07-015

Response to Portion of NRC Request for

Additional Information Letter No. 76

Related to ESBWR Design Certification Application

Instrumentation and Control

RAI Numbers 7.1-43, 7.2-33, 7.2-34, 7.2-36, 7.2-41 through 7.2-49, 7.3-3, through 7.3-6, 7.3-8, 7.3-9, 7.7-2, 7.7-5, and 7.9-15

NRC RAI 7.1-43

Describe the block on Figure 7.1-1 of DCD, Tier 2, Revision 1, identified as "Plant Computer Functions". Identify if this block is a separate hardware component or representative of the gateway to the various plant computers or is this a self contained system or component of the NE-DCIS.

GE Response

Plant Computer Functions (PCFs) is a term to refer to the nonsafety-related plant monitoring and information functions that are performed by the NE-DCIS. These functions are described in DCD, Tier 2, Rev 2, Section 7.9.2.

The block diagram (Plant Computer Functions) shown in Figure 7.1-1 is representative of various processors that are part of the NE-DCIS network. The PCFs are provided by redundant processors connected to the dual network of NE-DCIS. The detailed design and implementation process will determine the number of redundant processors for the PCFs.

DCD Impact

DCD, Tier 2, Section 7.9.2, will be revised in Rev. 3 to provide more detail of the architecture, philosophy, and composition of the Plant Computer Functions.

NRC RAI 7.2-33

DCD, Tier 2, Revision 1, Section 7.2.1.5.2, "Automatic and Manual Bypass of Selected Scram Functions," addresses more than 20 cases for various automatic and manual bypasses of selected scram functions. It is not clear how many bypasses are automatic by the protection system, and how many bypasses are required by operator action. How many switches on the control console will perform reactor trip system related function? Provide logic diagrams showing these bypasses, and permissive circuits.

GE Response

ESBWR DCD, Tier 2, Subsections 7.2.1.14.2.1 and 7.2.1.14.2.2 were revised in Revision 2 and clearly describe which bypasses are automatic and which bypasses required manual operation. GE has concluded that additional clarification in the form of a summary table is not necessary.

As described in DCD, Tier 2, Revision 2, Subsections 7.2.1.14.4, 7.2.1.14.5 and 7.2.1.14.5.1, one reactor mode switch, two manual scram switches and four divisional trip switches are provided on the control room console to permit manual initiation of reactor scram at the system level. Both manual scram switches must be depressed to initiate a RPS scram. Backup to the manual scram is provided by placing the reactor mode switch in SHUTDOWN position. There are four divisional trip switches provided on the control room console for optional use by the operator to trip the actuators that normally would be tripped by a scram condition for that division. Note that operating any two of the four divisional trip switches results in a full reactor scram.

The RPS system simplified logic diagrams were submitted by MFN 07-001.

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-34

DCD, Tier 2, Revision 1, Section 7.2.1.5.2, "Automatic and Manual Bypass of Selected Scram Functions," describes "Mode Switch" as a multi-function, multi-bank, control switch provides mode selection for the necessary interlocks associated with the various plant modes. It is not clear what specific position of the mode switch that relate to the bypass and reset functions of the protection system.

GE Response

ESBWR DCD, Tier 2, Subsection 7.2.1.14.4 will be revised in Revision 3 to clarify how the Mode Switch positions relate to the bypass and reset functions of the protection system as shown below.

7.2.1.14.4 Mode Switch

A multi-function, multi-bank, control switch placed on the main control console provides mode selection for the necessary interlocks associated with the various plant modes; namely, SHUTDOWN, REFUEL, STARTUP, and RUN. The switch provides both electrical and physical separation between the sections associated with each of the four separate divisions. The mode switch positions and their related bypass and trip/reset functions are as follows:

(1) SHUTDOWN
- Initiate a reactor scram
- Enable NMS non-coincident trips
- Enable manual CRD charging pressure trip bypass
- Automatically bypass Turbine Control Valve fast closure trip
- Automatically bypass Turbine Stop Valve closure trip
- Automatically bypass MSIV closure trip
- Enable automatic bypass of loss of power generation bus trip

(2) REFUEL
- Enable NMS non-coincident trips
- Enable manual CRD charging pressure trip bypass
- Automatically bypass Turbine Control Valve fast closure trip

- Automatically bypass Turbine Stop Valve closure trip
- Automatically bypass MSIV closure trip
- Enable automatic bypass of loss of power generation bus trip

(3) STARTUP

- Enable NMS non-coincident trips
- Disable manual CRD charging pressure trip bypass
- Automatically bypass Turbine Control Valve fast closure trip
- Automatically bypass Turbine Stop Valve closure trip
- Automatically bypass MSIV closure trip
- Enable automatic bypass of loss of power generation bus trip

(4) RUN

- Disable all trip bypasses enabled by any of the other three modes
    - Enable automatic bypass of NMS SRNM trip

<u>DCD/LTR Impact</u>

DCD Tier 2 Chapter 7 will be revised in Rev. 3 as described above.

NRC RAI 7.2-36

DCD, Tier 2, Revision 1, Table 7.2-2 and Table 7.2-3 listed "Typical Analytical Limit For Trip Setpoint (Note 1)." Note 1 stated that values in this table are typical, instrument accuracy will be considered based on the instrument setpoint methodology. It is the staff's understanding that the analytical limit should be based on the ESBWR's accident analysis, therefore, it is not a "typical" value. The trip setpoint will be determined based on plant-specific instrument selected that will be specified in the plant technical specification. Clarify "Typical Analytical Limit" in Tables 7.2-2 and 7.2-3.

GE Response:

ESBWR DCD, Tier 2, Chapter 7, Section 7.2, Tables 7.2-2 and 7.2-4 (was Table 7.2-3 in Revision 1) will be revised in Revision 3 to delete the word "Typical". The analytical limit values in these tables are confirmed by the final ESBWR accident analysis. Note 1 of Tables 7.2-2 and 7.2-4 will also be revised to delete first sentence and for clarification that the analytical limit is based on the ESBWR accident analysis.

DCD/LTR Impact

DCD Tier 2 Chapter 7 will be revised in Rev. 3 as described above.

NRC RAI 7.2-41

Describe the Bypass function shown in DCD, Tier 2, Revision 1,Figure 7.2-1 "RPS Functional Block Diagram." Please identify the inputs and outputs of the bypass unit.

GE Response

DCD, Tier 2, Revision 1, Figure 7.2-1 was revised in Revision 2 to depict the bypass function as the "sensor bypass" and the "DTLU bypass." These bypasses correspond to the "division of sensors bypass" and the "division of logic (division out-of-service) bypass," respectively, discussed in DCD, Tier 2, Revision 2 Subsection 7.2.1.2.4. Additional discussion of these bypasses is provided in DCD, Tier 2, Revision 2, Subsection 7.2.1.2.4.1 "Division of Trip Logic."

DCD/LTR Impact

There are no changes to DCD required by this response.

<u>NRC RAI 7.2-42</u>

The text of DCD, Tier 2, Revision 1, Section 7.2, Reactor Trip System, does not provide any information on this application of the Communication Interface Module. The staff requests the following:

a) Is this a 2-way communication link?

b) Identify the data, by functional description, that passes through this component.

c) Show how this communication provision is consistent with safety system separation and isolation requirements of IEEE-603 with regards to data transmission and cyber security, as well as electrical isolation, between a safety and non-safety system.

<u>GE Response</u>

The Communication Interface Module (CIM) has 2-way fiber optic communication data links. The GE NUMAC Licensing Topical Report No. NEDC-33288P which describes the CIM function, communication data link and data flow in the RPS application, will explain how the separation and isolation requirements of IEEE-603 with respect to data transmission and cyber security are met. This LTR will be submitted in accordance with the schedule described in MFN 07-004.

<u>DCD/LTR Impact</u>

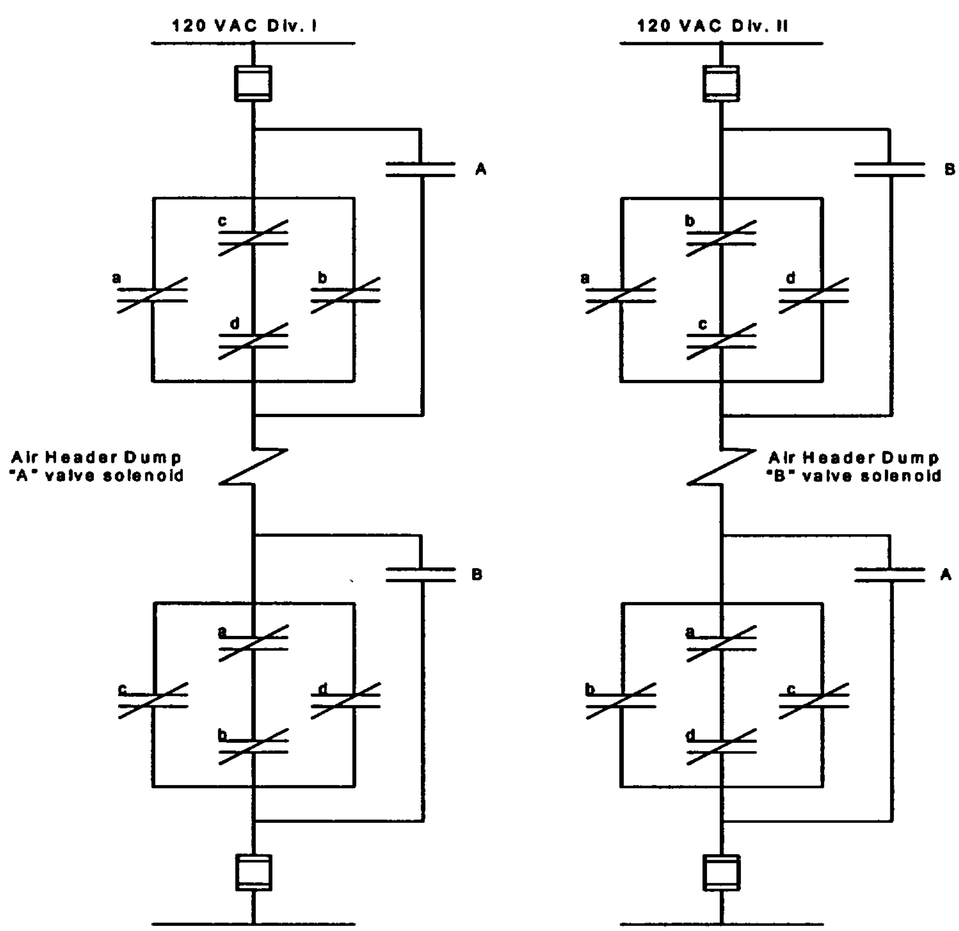
There are no changes to DCD required by this response.

NRC RAI 7.2-43

In DCD, Tier 2, Revision 1, Section 7.2.1.2.4, "Divisions of Trip Actuators", normally open relay contacts are described for the ESBWR, for energization of the air header dump valve solenoids to energize. Provide a Power Distribution Diagram which shows the normally closed scheme for that design.

GE Response

The backup scram logic circuitry performs RPS backup scram functions by operating air header dump valve solenoids. The power distribution diagram showing normally closed load drivers (a through d) arranged in 2-out-of-4 logic is provided in the following figure. The load drivers are located between the air header dump valve solenoids and 120 VAC class 1E power source so that, on a reactor trip (coil de-energized), the load driver contacts close to energize the air header dump valve solenoids. Holding contacts A and B keep the solenoids energized till the backup scram logic circuitry is reset.



DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-44

In DCD, Tier 2, Revision 1, Section 7.2.1.2.4, "Divisions of Trip Actuators", a brief hardware description of the load drivers explains it as an isolating feature of the system. Explain how this device performs the isolation function in the safety-related protection system.

GE Response:

As shown in figure 7.2-1 of DCD, Tier 2, Rev. 2, each of the two RPS Load Driver (LD) assemblies, one each in Divisions I and II, contains four load driver cards. Each of the four load driver cards controls the 120 VAC to one of the four scram groups. The Load Driver switch logic is hardwired, i.e. switches are arranged in series and parallel in order to accomplish the desired logic function. The final logic is accomplished by switching the 120 VAC power to the scram solenoids.

The load drivers normally operate in the "closed" state (conducting) and open (interrupt current) to provide a scram trip input to the final load driver hardwired logic. The Load Driver contains a microcontroller with firmware that implements the self-test function and controls the status indication devices on the front panel. The isolation function of the load driver is achieved by coil contacts so that any firmware fault does not impair the safety related function of the Load Driver Module.

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-45

In DCD, Tier 2, Revision 1, Section 7.2.1.2.4.2, "Initiating Circuits", in order to understand the statement "... and Manual Scram outputs, which are provided directly to the RPS by dedicated fiber optics or hardwire signals, the rest ...", reword the statement to identify which outputs are fiber optic and which are electric wired.

GE Response

ESBWR DCD, Tier 2, Subsection 7.2.1.2.4.2 was revised to identify which outputs are fiber optic and which are hard-wired in Revision 2. The MSIV closure, turbine stop valve closure, turbine control valve fast closure, loss of power generation bus, manual scram outputs and main condenser pressure high signals are provided to the RPS through hard-wired connection while the NMS outputs and signals are provided to the RPS through fiber optic connection.

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-46

As in DCD, Tier 1, Revision 1, Section 2.2.7, Reactor Protection System, the conditions "Short period power increase" and "Main Condenser Vacuum Low" are listed. These conditions are not listed in Section 7.2.1.2.4.2 which causes the RPS logic to initiate a reactor scram. Clarify the discrepancy between Tier 1 and Tier 2 information.

GE Response:

Main condenser pressure high discussed in DCD, Tier 2, Revision 1, Subsection 7.2.1.2.4.2 is the primary scram signal for the main condenser vacuum low of DCD, Tier 1, Revision 1 Section 2.2.7.

The item "NMS-monitored SRNM and APRM conditions exceed acceptable limits" listed in DCD, Tier 2, Subsection 7.2.1.2.4 includes the SRNM Short Period Trip listed in Table 7.2-2. This limit/trip corresponds to the "Short period power increase" of DCD, Tier 1, Revision 1, Section 2.2.7.

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-47

In DCD, Tier 2, Revision 1, Section 7.2.1.2.4.2, Initiating Circuits, "Outputs to Main Control Room Panels", Displays, Add or please explain why Condenser Pressure and NMS outputs should not be added to the list of RPS scram variables.

GE Response

Revision 2 of ESBWR DCD, Tier 2, Subsection 7.2.1.7.1.2 incorporated a change to include condenser pressure and NMS outputs for the main control room panel display.

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-48

In DCD, Tier 2, Revision 1, Section 7.2.1.2.4.2, Initiating Circuits, "Outputs to Main Control Room Panels", Alarms, page 7.2-12, please identify which alarms, related to RPS status, are dedicated and which are soft alarms.

GE Response

The following list identifies which alarms related to RPS status described in DCD, Tier 2, Revision 2, Sub section 7.2.1.7.1.2 are dedicated to RPS status and which are soft alarms.

- Alarms related to RPS status:
  - RPS NMS trip (generated in NMS)
  - Reactor vessel pressure high
  - Reactor water level low (≤ Level 3)
  - Reactor water level high (≥ Level 8)
  - Containment (drywell) pressure high
  - MSIV closure trip
  - TSV closure
  - TCV fast closure
  - Main condenser pressure high
  - Loss of Power Generation Bus (Loss of Feedwater Flow)
  - CRD HCU accumulator-charging-header-pressure low
  - Suppression pool temperature high
- Soft Alarms:
  - RPS divisional automatic trip (auto-scram) (each of the four, i.e., Div. I, II, III, IV automatic trip)
  - RPS divisional manual trip (each of the four, i.e., Div. I, II, III, IV manual trip)
  - Manual scram trip (two: both Manual A and/or Manual B)
  - Mode switch in SHUTDOWN
  - SHUTDOWN mode trip bypassed
  - NON-COINCIDENT NMS trip mode in effect (in NMS)
  - NMS trip mode selection switch still in NON-COINCIDENT position with plant in RUN mode (in NMS)

- Division of channel A (or B, C, D) sensors bypassed (four);
- Tripped conditions in Channel A (or B, C, D) and Channel A (or B, C, D) sensors bypassed (four)
- Division I (or II, III, IV) TLU out-of-service bypass (four);
- Bypass of CRD accumulator-charging-header-pressure low trip;
- Any CRD accumulator-charging-header trip, bypass switch still in BYPASS position with plant in STARTUP or RUN mode; and
- Auto-scram test switch in TEST mode (manual trip of automatic logic) (four).

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.2-49

Please explain if the following alarms should be included for providing RPS status, in DCD, Tier 2, Revision 1, Section 7.2.1.2.4.2, "Outputs to Main Control Room Panels", Alarms, page 7.2-12:

Neutron Flux High High

Control Rod Not Inserted

Suppression Pool water level

Drywell Temperature High

GE Response

The Neutron Flux High High alarm is part of the Neutron Monitoring System (NMS) trip alarm. The Startup Range Neutron Monitor (SRNM) and Average Power Range Monitor (APRM) trip signals are generated in NMS to prevent fuel damage in the event of any abnormal reactivity insertion transients including high high neutron flux level or excessive neutron flux increase rate.

The Control Rod Not Inserted alarm is not part of RPS. There are two RCIS alarms for post scram - one is that all rods are not at zero and the other is that all rods are not inserted past X (where X is no possibility of criticality). The alarms are in the plant alarm system and also on the main mimic. Therefore, indication of an abnormal condition is provided in the control room.

The Suppression Pool Water Level alarm signal is not part of RPS. The suppression pool temperature high alarm is credited in RPS for the suppression pool water level alarm. When water level drops below selected temperature sensors, RPS gets an alarm due to inoperable temperature detection. Therefore, indication of an abnormal condition is provided in the control room.

The drywell temperature high alarm is non-safety related and is provided in the control room by Containment Inerting System (CIS).

DCD/LTR Impact

There are no changes to DCD required by this response.

NRC RAI 7.3-3

DCD, Tier 2, Revision 1, Figure 7.3-1A, "SRV Initiation Logics, "indicates diverse means to actuate Safety Relieve Valve. However, three circuits look the same. Please identify the diversity characteristics between the ECCS-SSLC circuitry and the DPS circuitry in Figure 7.3-1A.

GE Response

Figure 7.3-1A has been revised in DCD, Tier 2, Revision 2 and a new figure (Figure 7.3-1C) has been added to clarify the DPS circuitry. The logic for the ECCS-SSLC and the DPS portions of the SRV initiation logic/circuitry is essentially the same. However, the diversity between the two is that each is implemented on different hardware platforms using different software specific to each platform. Each platform is designed and built by a different manufacturer and has different architectures. This meets the Design Diversity and Equipment Diversity criteria in Guideline 2 of NUREG/CR-6303, Section 3. Each of these systems uses similar RPV water level sensors yet they are different redundant sets of sensors powered from different sources of power. This meets the Signal Diversity criteria in Guideline 2 of NUREG/CR-6303, Section 3.

DCD Section 7.8.1.2.2, Tier 2, Revision 2 describes the ESF portion of the DPS.

DCD Section 7.3, Tier 2, Revision 2 describes the primary ESF system.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.3-4

DCD, Tier 2, Revision 1, Section 7.3.1.1.3, "Safety Evaluation," stated that ECCS initiating instrumentation must respond to the potential inadequacy of core cooling regardless of the location of the breach in the reactor coolant pressure boundary. Identify the instrument location and the equipment qualification requirement of the reactor vessel level and drywell pressure instrumentation that will perform the mitigation function. Are these sensors qualified to function in harsh environment? Discuss the response time of these instrument channels in response to various pipe break locations.

GE Response

The design of the ESBWR has been changed to add additional inventory to deliver more water to the vessel during a LOCA and to avoid ADS/GDCS initiation for LOFW or SBO events. As a result only the L1 setpoint is required to initiate ECCS. The RPV level L1.5 and 15 minute time delay and the level L1.5 and high drywell pressure initiation parameters are no longer applicable. DCD, Tier 2, Revision 2, Section 7.3 has been revised to remove any reference to level L1.5 and drywell pressure as ECCS initiating parameters. Drywell pressure instrumentation is no longer used for ECCS initiation.

RPV level instruments are located outside containment as stated in Section 7.3.1.1.3.4, "Regulatory Guides (RGs)", under the bullet for RG 1.118 of DCD, Tier 2, Revision 2.

Safety-related RPV level instruments are qualified for the environment in which they must perform their safety function as stated in Section 7.7.1.1.1, "Safety (10 CRF 50.2) Design Basis", and Section 7.7.1.3, "Safety Evaluation", of DCD, Tier 2, Revision 2.

The response times for the level channels are in the order of magnitude of hundreds of milliseconds, much faster than a change in the reactor level due to a pipe break in any location. The response of the ECCS to design basis LOCA is discussed in Sections 6.3.3.4 and 6.3.3.7.4 of DCD, Tier 2, Revision 2. Additionally, there is a 10 second delay following receipt of a voted L1 signal to confirm the ECCS initiation signal as noted in Table 6.3-1 of DCD, Tier 2, Revision 2. This delay is very large in comparison to the level instruments response time regardless of the instrument locations.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.3-5

Address 10 CFR 50.34(f)(2)(vii), TMI item II.K.3.18, "Perform a feasibility and risk assessment study to determine the optimum automatic depressurization system (ADS) design modifications that would eliminate the need for manual activation to ensure adequate core cooling." This item was not listed on DCD, Tier 2, Revision 1,Table 1A-1, TMI Action Plan Items. If this TMI Action Plan item is not applicable to ESBWR design or is addressed in other DCD section, then DCD Table 1A-1 should provide justification or reference section number for this item.

GE Response

TMI item II.K 3.18 – Optimum ADS, is addressed in Table 1A-1 on Page 1A-4 of DCD, Tier 2, Revision 2.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.3-6

Address 10 CFR 50.34(f)(2)(x), TMI item II.K.3.28, "Perform a study to ensure that the ADS valves, accumulators, and associated equipment and instrumentation will be capable of performing their intended functions during and following an accident situation, taking no credit for non-safety related equipment or instrumentation, and accounting for normal expected air (or nitrogen) leakage through valves." This item was not listed on DCD, Tier 2, Revision 1, Table 1A-1, TMI Action Plan Items. If this TMI Action Plan item is not applicable to ESBWR design or is addressed in other DCD section, then DCD Table 1A-1 should provide justification or reference section number for this item.

GE Response

TMI item II.K 3.28 – ADS requirements, is addressed in Table 1A-1 on Page 1A-6 of DCD, Tier 2, Revision 2.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.3-8

DCD, Tier 2, Revision 1, Section 7.3.1.2.2, GDCS System Description stated that once the initial start signal is given to both ADS and GDCS (starting the various timers), the sequence is sealed in and cannot be aborted by the plant operator. It is also possible for the operator to manually initiate the equalizing valves or to individually fire the various squib initiators independently by injecting trip signals to the automatic logic. Please provide a logic or schematic diagram to illustrate the provisions of both automatic and manual control of the squib valves in the GDCS.

GE Response

A GDCS system simplified logic diagram was submitted by MFN 07-001.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.3-9

During July 26 and 27, 2006 I&C meeting, the applicant presented the proposed ECCS/ESF Platform Family. A topical report describing the detailed hardware configuration that implements the instrumentation and control architecture for the ESBWR ECCS/ESF Functions should be provided. The report should address how the ESBWR ECCS/ESF actuation system design is in conformance with IEEE Std 603-1991.

GE Response

A Licensing Topical Report is currently being developed for the ECCS/ESF platform that will contain a more detailed description of the platform and how the platform conforms to IEEE Std 603. Additionally, NEDO-33294 is currently being developed to address overall compliance of the ESBWR instrumentation and control systems to IEEE Std 603. These LTRs will be submitted in accordance with the schedule described in MFN 07-004.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.7-2

In DCD, Tier 2, Revision 1, Section 7.7.1.4, it is stated that various sensors "are located outside the drywell so that calibration and test signals can be applied during reactor operation." To what level of involvement will this require the technician or operator at the sensor location and if this would be done any differently than current outage calibrations which include the sensors.

GE Response

Sensor calibrations will be performed once per Refueling Cycle in accordance with Technical Specification surveillance requirements for Channel Calibration. We have the capability and the desire to calibrate instruments for their TS requirements during operation.

Sensor calibration will not be done any differently during reactor operation. The channel of sensors will be bypassed and the appropriate TS Action Statements will be entered for the duration of the bypassed condition.

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.7-5

In DCD, Tier 2, Revision 1, Section 7.7.4.2, the simple statement is made that the fault-tolerant digital controllers (FTDC), and the redundant system controllers perform the Plant Automation System (PAS) control functional logic. Explain the different functional scope of the FTDC versus the redundant system controllers which both perform the PAS functional logic."

GE Response

The primary objective of the Plant Automation System (PAS) is to coordinate operation of certain Balance Of Plant (BOP) systems required for plant start-up, operation, and shutdown and to set reactor temperature, pressure, power and neutron flux to those values required by the automation scheme. The PAS also has the ability to pull the reactor critical and heat it to rated temperature and pressure from either a cold or hot standby condition. The PAS can also bring the reactor down to cold shutdown conditions.

The PAS consists of both dual and triply redundant process controllers; these receive information from the various plant sensors and issue commands to the BOP system controllers and to RCIS to position control rods and to the Steam Bypass And Pressure Control (SB&PC) System to set pressure. While triply redundant controllers provide commands to the main reactor control systems, the dual controllers provide other Nuclear Island and BOP automation functions by providing the set-points of lower level controllers and commands to various BOP equipments for normal plant startup, shutdown, and power range operations.

In general, the key ESBWR boiler control systems such as the feed-water control, turbine control, automatic power regulator and reactor pressure regulator systems are based on the triplicated, microprocessor-based Fault Tolerant Digital Controllers (FTDCs). The remaining important BOP control systems are based on dual redundant FTDCs.

It should be noted that system control is only in that system's logic and the PAS only issues "supervisory" commands to be carried out by system controllers; all automatic and manual reactor protection and BOP protection functions are always operative and cannot be bypassed by any automation control.

Table One below contains a list of the plant control systems that are interfaced to the PAS. It also stipulates which are based on the triplicated, microprocessor-based FTDC and which are based on dual redundant FTDCs.

	System Name	Minimum Redundancy Level
1.	Plant Automation System (PAS) – Power Generator Control System (PGCS)	Dual Redundant

System Name		Minimum Redundancy Level
2.	Plant Automation System (PAS) – Automatic Power Regulator (APR)	Triply Redundant
3.	Chilled Water System (CWS)	Dual Redundant
4.	Condensate & Feed-Water (C&FS)	Dual Redundant
5.	Heater Drain And Vent System (HDVS)	Dual Redundant
6.	Electric Power Distribution System (EPDS)	Dual Redundant
7.	Feed-Water Control System (FWCS)	Triply Redundant
8.	Make-Up Water System (MWS)	Dual Redundant
9.	Neutron Monitoring System (NMS)	Safety – Four Divisions
10.	Essential Distributed Control Information System (E-DCIS)	Safety – Four Divisions
11.	Non-Essential Distributed Control Information System (NE-DCIS)	Dual Redundant
12.	Reactor Protection System (RPS)	Safety – Four Divisions
13.	Reactor Water Clean-Up and Shutdown Cooling System (RWCU / SDC)	Dual Redundant
14.	Rod Control And Information System (RC&IS)	Dual Redundant
15.	Steam Bypass And Pressure Control System (SB&PC)	Triply Redundant
16.	Turbine Component Cooling Water System (TCCWS)	Dual Redundant
17.	Turbine Control System (TCS)	Triply Redundant
18.	Generator	Triply Redundant
19.	Utility Grid Management System	Redundancy Level To Be Specified By Owner

Additional information for the Plant Automation System shown on DCD, Tier 2, Rev. 2 Figure 7.7-4, "Plant Automation System Simplified Functional Diagram."

DCD/LTR Impact

No DCD changes will be made in response to this RAI.

NRC RAI 7.9-15

Alarm management is critical under plant upset, transients, and other conditions when a large number of simultaneous alarms may be generated. Large numbers of alarms can be confusing to an operator. The alarm system filtering, prioritization, and group should be handled in such a way that it enhances operator actions. A brief description of the alarm & annunciation is provided in Section 7.9.2.1 of the DCD, Tier 2, Revision 1 document. Please describe the philosophy of alarm management system, keeping in mind the human factor considerations. Is color coding of the alarms defined to enhance operator actions? Is determination of the first out alarm as a means of trip or transient analysis a part of the system design? Is the time tagging carried out at the millisecond level as part of the sequence of events (SOE) recording?

GE Response

The alarm management system is developed as an integral part of the Human Factors Engineering process (DCD, Rev 2, Chapter 18). The HFE process follows NUREG-0700, Revision 2, which states that the basic functional requirements of the alarm management system is to alert the operator to deviations, informing the operator of its priority, guiding the operator's response, and confirming whether the response was effective. To fulfill these basic functions, the system must:

- Detect and, perhaps, predict the occurrence of changes in the plant
- Alert operators to changes important for the current operating situation such that
  - Only operationally relevant changes are alarmed
  - The demands imposed on users' attention to recognize the changes fit with the demands of other concurrent control room tasks
- Point users to additional plant information to understand and respond to changes

To accomplish the above, the ESBWR alarm management system uses the following design bases described in DCD, Rev 2, 7.9.2.1.2:

- Alert the operator to off-normal conditions in a timely manner, which require them to take action
- Reduce the number of alarms effectively to reduce the operator's workload
- Guide the operators to the appropriate response
- Assist the operators in determining and maintaining an awareness of the state of the plant and its systems or functions
- Integrate with other information systems to facilitate the operator's tasks

The alarm management human factoring provides several functions to enhance the alarm presentation, minimize the burden to and enable the operator to make intelligent decisions based on the best available information.

Alarm definition, processing, prioritization, display, control and management are fundamental to the design philosophy and will follow the guidance given in NUREG-0700, Section 4. The ESBWR Human Factors Guidance Manual discussed in the response to RAI 18.8-1 will provide the detailed guidance for alarm color coding and presentation.

Time tagging at the millisecond level is a function of sequence of events recording and includes the capability of first-out determination and event analysis. The resolution of time tagging will be determined, based on the speed of the monitored process variable, the origin (NE-DCIS, E-DCIS or other gateway), and the available technology. This function is described in Section 7.9.2.1.2 of the DCD, Tier 2, Revision 2, under the headings of Historian and Transient Recording and Analysis (TRA) and Sequence of Events (SOE) Recording.

DCD Impact

Revision 3 of the DCD, Tier 2, Section 7.9.2 will provide more detail of the architecture and philosophy of the ESBWR alarm management design requirements.